30 April 2014

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Dear John McLaren

Issues paper 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 "*Default price-quality paths from 1 April 2015 for 17 electricity distributors: Process and Issues paper*" (**Issues paper**) published on 21 March 2014.

WELL's submission covers the following:

- The Commission's approach to the 2015-20 Default Price-quality Path (**DPP**) reset;
- Forecast operating expenditure;
- Forecast capital expenditure;
- Forecast constant price revenue growth;
- Term credit spread differential allowance;
- Quality standards and incentives;
- Uncertainty and risk; and
- Incentive schemes.

2. Commission's approach to the 2015-20 DPP reset

The Issues paper indicates that the Commission intends to apply the same methods to determine the 2015-20 DPP as it applied for the 2012 mid-period reset of the DPP, unless new information is submitted through consultation. The Issues paper does not show any analysis of the performance of the existing methods, propose any developed new approaches or indicate any refinements to the existing methods.

WELL considers that each time the DPP is reset the Commission should be analysing the performance of its existing methods and considering and consulting on potential new methods and/or incremental improvements or revisions to existing methods. This process is important for ensuring the DPP evolves through time and the best available forecasting approaches are applied, given all the available data. Such an approach also limits the likelihood of modelling anomalies and errors compounding over time.

The Issues paper currently suggests that the onus is on stakeholders to develop and propose any changes to the existing models. WELL considers that the onus should be on both the stakeholders and the Commission to ensure that the best possible approaches are employed at each DPP reset. WELL therefore strongly encourages the Commission to assess the performance of its current models, review its models given the additional data available and engage closely with the stakeholders through the DPP reset process as it undertakes the development of any new models or any changes to the existing models.

3. 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.

3.1. 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 and current regulatory obligations.

WELL supports using the 2013/14 opex data only as the base year for forecasting future opex requirements. The opex for 2013/14 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. EDB's 2013/14 opex may be higher than prior years' historical opex due to a number of factors including:

- Increased input costs reflecting the rebound in the New Zealand economy. It is unclear from the Issues paper whether the Commission has escalated prior years' opex to 2013/14 dollars using the labour and materials input cost escalators. The Electricity Gas Water and Wastewater Labour Cost Index increased 2.6% in the year to December 2013 and the all industries Producer Price Index increased by 2.8% over the same period;[1]

- Changes in network condition and scale leading to increased operating and maintenance expenses;

- Increased regulatory compliance obligations, including:

    - The 2013/14 year included the first year of implementation of the new Information Disclosure Requirements (**IDRs**) which were first due in August 2013. Implementation of these new obligations resulted in WELL engaging additional resource on a permanent basis to manage the implementation and ongoing reporting and compliance with the new IDRs. These costs are ongoing and should be reflected in the base year opex used for forecasting future opex; and

    - Increased costs for compliance with Public Safety Management Systems and the new *WorkSafe New Zealand Act 2013* which require higher levels of resources and administration;

- Specifically in WELL's case, the 2013/14 year marks five years from the acquisition of the network and establishment of the business by new management. Over prior years WELL has been growing its knowledge about the business requirements and the condition of network assets, and is now reaching a level of maturity. Therefore the most recent opex for 2013/14 is the best basis for forecasting WELL's future opex requirements.

The Commission is also consulting separately on applying an opex incentive scheme for the 2015-20 DPP. An opex incentive scheme, such as the Incremental Rolling Incentive Scheme (**IRIS**) relies on the penultimate year being used as the base year to set the opex forecasts in the next regulatory period. As demonstrated in attachment A, using the penultimate year to set future allowances is necessary to maintain neutral incentives for EDBs to seek efficiency gains across the regulatory period. Using a historical averaging approach to set future opex allowances distorts the incentive properties of an IRIS scheme. Consequently, if there is any doubt that the Commission will use the penultimate year to set future opex forecasts then under an IRIS EDBs will be dis-incentivised from making efficiency improvements prior to year 4 (penultimate year) of the regulatory period. This would be contrary to the purpose of an incentive scheme designed to smooth incentives across the regulatory period so that consumers benefit from efficiency improvements as soon as these are identified and able to be implemented by EDBs.

[1] Sourced from Statistic New Zealand.

It is clear from this analysis that if the Commission intends to implement an IRIS for the 2015-20 DPP, it needs to provide a commitment to using the penultimate year as the base year. As there is no Input Methodology (**IM**) relating to opex forecasting, WELL considers that the best way the Commission can achieve this, is by applying the 2013/14 year as the base year for the 2015-20 DPP reset. In doing so would establish a consistent approach to setting the base year through multiple DPP resets.

Notwithstanding the above, if the Commission does utilise a historical averaging approach to set the base level of opex then it must adjust all prior years' costs to reflect:

- Actual 2013/14 network condition and scale;
- Actual 2013/14 input costs using labour and materials input cost escalators (not CPI which reflects output prices rather than input prices);
- Increased regulatory compliance costs;
- Appropriate allowance for demonstrable cost changes from the start of the historical period to the end of the period; and
- The 2013/14 term credit spread differential allowance since this is most reflective of the EDB's current debt portfolio (subject to the refinements proposed in section 6 of this submission to deal with the absence of the Bloomberg New Zealand 'A' fair value curve).

Given the above adjustments required if a historical averaging approach is applied, it is clearly more efficient for the Commission to set the 2013/14 year as the base year for opex.

3.2. Input cost escalation

For the 2012 mid-period DPP reset the Commission 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 therefore are not necessarily reflective of input cost changes specific to the electricity distribution industry.

In particular, the growth in labour costs in the electricity distribution sector exceeds that of the general economy because:

- Highly specialised labour is required and is in short supply in New Zealand;
- Over time labour rates are common due to the 24 hours 7 days a week nature of the work and over time labour rates are rising to ensure sufficient labour is available during out of business hours.

This is demonstrated in table 1 below, there is a substantive difference in the annual average labour cost growth recorded for the general economy by the all industries LCI compared with:

- Labour cost growth recorded for the Electricity Gas Water and Wastewater (**EGWW**) sector; and
- Labour cost growth recorded by Strategic Pay remuneration consultants which is based on a representative survey of approximately 25 transmission and distribution networks in New Zealand.

Table 1: 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	3.08%

Source: Statistics New Zealand, Strategic Pay

While the Commission has raised some concerns regarding the volatility of sub-indices, the EGWW LCI is developed through surveys which include approximately 50% of EDBs in New Zealand and EDBs make up approximately 50% of the employers sampled to develop the index. The EGWW LCI is therefore a more representative index than the all industries LCI. Furthermore, as demonstrated by Frontier Economics[2] the volatility appears to be more related to intra-quartile volatility, rather than annual volatility, which most likely reflects the timing of pay reviews in the sector.

WELL recommends that the Commission apply the EGWW LCI for the 2015-20 DPP. This index is more representative of the labour cost changes in the electricity distribution sector than the all industries LCI which includes sectors of the economy which have vastly different skill sets and different labour demand and supply conditions to the electricity distribution sector.

3.3. Scale escalation

Consistent with the suggestions made by Frontier Economics[3], WELL considers that the Commission should review its scale escalation model to:

- Include updated data available for 2013 and 2014;
- Include at least two size variables in each of the network and non-network opex models, where at least one of those variables enters the model in density form in order to mitigate potential multicollineraity problems[4]; and
- Test whether additional explanatory variables should be included.

WELL looks forward to engaging further with the Commission as it develops an updated scale escalation model.

3.4. Step changes

WELL considers that there are two key step changes in opex requirements for the 2015-20 DPP period that are not reflected in historical opex. Each of these step changes should be incorporated into EDBs opex forecasts for the 2015-20 period. To validate the magnitude of the step changes the Commission should request that EDBs provide forecasts which have been subject to independent verification. EDBs could have a choice not to receive a step change if they do not consider the cost increases to be material for their network.

Resilience opex

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 90 notifications from the Wellington City Council, at least 1/3 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.

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2 Frontier Economics, *Output 1 Top down approaches to forecasting EDB costs under a DPP framework*, April 2014, page 93.

3 Frontier Economics, Output 1: '*Top-down approaches for forecasting EDB costs under a DPP framework*', report prepared for the Electricity Networks Association of New Zealand, April 2014.

4 In econometric analysis when multiple independent variables are highly correlated with each other it can create difficulties in identifying the causal link between each of the independent variables and the dependent variable. This is known as multicollinearity.

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 is cost efficient for consumers as 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 aspect of this programme will be undertaken and completed during the 2015-20 DPP period. WELL forecasts that the assessment activity will require additional opex of $1.4M (nominal) during the 2015-20 DPP period. 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 Parliament is passed into law. 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 event.

Allowance for catastrophic risk – lost revenue

As noted in section 8.2, WELL does not agree with the Commission's position that EDBs should not be compensated for managing catastrophic risk. As stated by Professor Yarrow, the costs of managing catastrophic risk must be compensated through the regulatory regime either ex ante or ex post.[5]

The Commission has determined, through its final decision on Orion New Zealand (**Orion**) Customised Price Path Proposal (**CPP**) that it will not provide ex post recovery of Orion's lost revenue following catastrophic events such as earthquakes. This decision sets the precedent for future decisions that the Commission will make and reflects the Commission's position in the Issues paper. Therefore it is necessary for the Commission to provide ex ante compensation to EDBs for the costs of managing the risk of potential revenue losses resulting from catastrophic events.

WELL therefore recommends that the Commission provide a step change in the opex forecasts for the costs to EDBs of managing the risk of revenue losses associated with catastrophic events. Failure to provide such an allowance would result in EDBs not being permitted to recover expected costs, particularly for those EDBs with high exposure to catastrophic events.

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

4. Forecast capital expenditure

4.1. Capex forecasts

WELL considers that the Asset Management Plans (**AMP**) produced by EDBs should continue to be relied on by the Commission for forecasting capital expenditure (**capex**), including network and non-network capex. AMPs are developed through 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 consider it appropriate for the Commission to set forecast capex based on an arbitrarily chosen cap above historical expenditure. WELL's historical expenditure is not representative of its capex requirements over the 2015-20 period. As noted above, WELL has only operated in its current form since 2009 and it takes time to build knowledge about the condition of network assets.

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.[6] 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 will be 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.

As noted in section 3.4, WELL is undertaking seismic assessment and upgrade (where required) of substation buildings to ensure compliance with the Building Code and enhance the resilience of the network in the event of a major earthquake. The majority of WELL's seismic strengthening capital works programme will also be undertaken during the 2015-20 DPP period. WELL has approximately 320 pre-1976 buildings to assess and has already received approximately 90 council notifications at least 1/3 of which indicate that the building may be earthquake-prone. WELL's 2014 AMP capex forecasts include a total of $33 million (nominal) for seismic strengthening work, $17 million (nominal) of which is forecast for the 2015-20 DPP period. This earthquake resilience capex will improve the security of supply into Wellington, reduce restoration times for vulnerable cable assets and enable substation buildings to remain operational following an earthquake. Resilience capex is necessary to meet the Building code requirements and ensure that social welfare and economic activity is not unduly impacted due to prolonged supply outages as a result of damage to strategic assets following a major earthquake.

Importantly, WELL's 2014 AMP only includes the capex required to meet the current legislative requirements relating to earthquake prone buildings which related to pre-1976 buildings only. However, if the *Building (Earthquake-prone Buildings) Amendment Bill* currently before parliament is passed into law, additional costs would be incurred. This is because the Bill would require pre-2005 buildings to be assessed and strengthened to at least 34% of the 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 5 years, if this applies to electricity network assets then WELL's seismic strengthening capex currently planned for post-2020 would 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.

While WELL acknowledges the Commission's concern that EDBs AMPs are subject to potential for forecasting error, it is important for the Commission to keep in mind the relative impact of potentially over-estimating capex requirements in the context of the overall price path, compared with the impact of under-estimating capex requirements.

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

WELL considers that the consequences of potentially over-estimating capex is limited because, unlike opex forecasts, any over-estimation is not passed directly through to consumers as the price path only allows for the recovery of the return on forecast capex and depreciation of forecast capex over 45 years. Second, any over-estimation of the capex forecast is automatically corrected for each time the DPP is reset because only actual capex is rolled into the RAB.

Conversely, the impact of under-forecasting capex requirements could have significant costs to both consumers and EDBs, particularly if capex allowances are insufficient to maintain network performance and consequently reliability is reduced. Empirical studies show that the customer value of reliability is very high due to the large economic losses resulting from interruptions to supply. Consequently, under-investment has large economic costs. Furthermore, additional costs would be incurred if EDBs must undertake CPP applications to ensure sufficient capex forecasts are provided to maintain network performance.

WELL therefore considers it appropriate that the Commission rely on EDB capex forecasts prepared in the AMPs as the primary method for forecasting capex for the 2015-20 DPP. The Commission could develop models/approaches which provide a cross check on the reasonableness of EDB AMP forecasts.

4.2. Age-based replacement capex models

The Issues paper indicates that the Commission intends to develop age-based replacement capex models. WELL supports the development of category-level capex models which can be used as a cross check on EDBs AMP forecasts. WELL is concerned, however, that the Commission has not allowed sufficient time to develop these models for implementation for the 2015-20 DPP reset. The Commission should develop age-based replacement models, and any other type of category-level capex models, through a thorough consultation process with the industry. Importantly category-level capex models require high quality data over an extended period of time to ensure that the outputs of the model can be relied upon for assessing EDBs capex forecasts.

If the Commission does develop age-based replacement models for the 2015-20 DPP reset then these should only be used as a reasonableness check on EDBs AMP forecasts and should not be used deterministically to directly set capex forecasts for the DPP.

4.3. Depreciation of non-network assets

Under the current DPP all assets are depreciated assuming a 45 year asset life. This creates a disincentive to invest in shorter life non-network assets, such as IT, as the costs of these assets are not fully recovered through the return of capital building block. This is because under the IDRs assets with shorter lives will be depreciated in accordance their actual expected asset life and the IDR RAB is then used for setting the opening RAB value for the next DPP period. Consequently, EDBs cannot recover the full value of depreciation for shorter life non-network assets as these are largely depreciated through the IDRs with very little recovered in the regulatory depreciation allowance. For example:

- A non-network asset valued at $1M with an asset life of 5 years is forecast to be purchased in year 1 of the regulatory period.
- The regulatory depreciation allowance provided under the DPP is $22K per annum ($1M/45) and $111K over 5 year regulatory period.
- For the purposes of the IDRs the asset is fully depreciated at the end of year 5 of the regulated period. The depreciation under the IDRs is $200K per annum and $1M over the regulatory period. The closing RAB value for the asset in year 5 is nil.
- For the next DPP period the RAB value of the asset is nil (as it is based on the IDR RAB) and therefore the depreciation allowance is nil.
- Consequently, the EDB only recovers $111K of the total $1M in depreciation and never recovers the remaining $889K.

To address this issue, WELL recommends that the Commission calculate forecast depreciation for non-network assets based on a shorter asset life assumption by providing key non-network asset category allowances e.g. software consistent with Inland Revenue Department depreciation rates.

4.4. Input price escalation

For the 2012 mid-period reset the Commission applied the all industries Capital Goods Price Index (**CGPI**) to determine the nominal capex forecasts. The all industries CGPI price index is based on the general economy and includes a very large proportion of commodity prices that do not relate to the electricity distribution sector and therefore does not reflect changes in capital input costs experience by EDBs.

WELL recommends that the Commission investigate replacing the all industries CGPI with either:

- A weighted average of a set of sub-indices of the CGPI which are more relevant to the electricity distribution industry. Specifically the Electricity distribution and control apparatus CGPI, Electrical works CGPI and the Insulated works and cable; optical fibres cables CGPI; or

- A weighted average materials index which reflects the key material inputs contributing to EDBs capital expenditure including copper, aluminium and steel. Such an approach would be similar to that developed by Orion for its CPP and Transpower for its Individual Price Path. The Commission could source forecasts for NZ dollar based materials prices from an expert consultant.

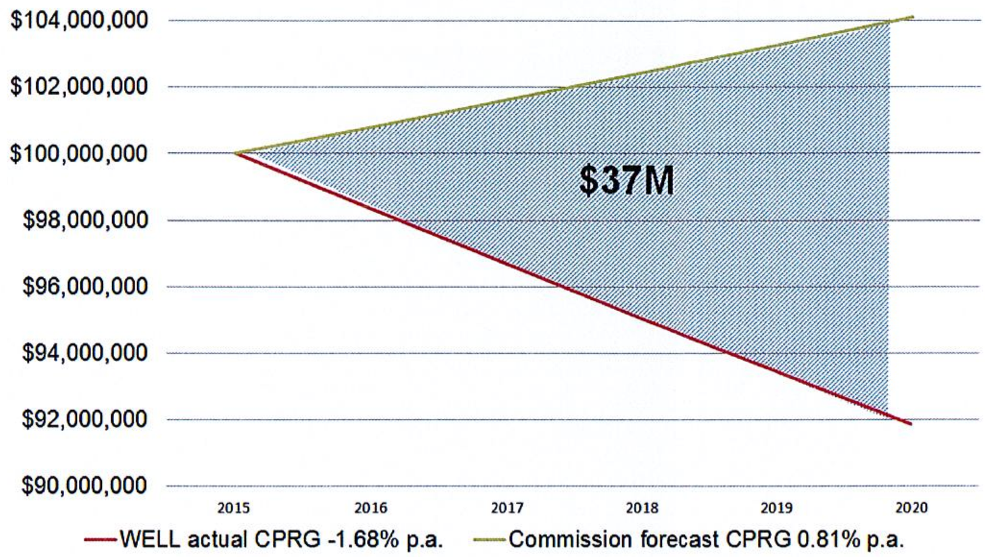
For the purposes of the 2015-20 DPP, the Commission could apply a simple approach to determine the weights to apply to combine the different indices, and could apply the same weights to all EDBs. The weights could be developed by engaging an engineering adviser and/or through industry consultation as part of the DPP reset process. Such an approach would be an improvement on the all groups CGPI which is economy wide and not reflective of industry specific cost changes.

5. Forecast constant price revenue growth

5.1. Demand risk associated with constant price revenue growth forecasts

For the 2012 mid-period DPP reset the Commission's constant price revenue growth model significantly over-estimated WELL's constant price revenue growth for the 2010-15 DPP period. The Commission applied a constant price revenue growth forecast of 0.81% per annum. Wellington's average actual constant price revenue growth for the first four years of the regulatory period was -1.68% per annum. Consequently, the Commission's model over-estimated constant price revenue growth by 2.5% per annum. As demonstrated in figure 1 below, over a five year period, a difference of this magnitude would lead to a loss of 7.4% of revenue, equivalent to $37 million (M).[7]

Figure 1: Impact on revenue of difference between actual and forecast constant price revenue growth over five year regulatory period



WELL strongly disagrees with the Commission's position in the Issues paper that EDBs can manage demand risk associated with differences between actual and forecast constant price revenue growth for the following reasons:

- EDBs cannot, and should not try to, influence the volume of energy consumed by its customers. Such a position would have an economically inefficient impact across the electricity supply chain and would be contrary to public policy objectives of improving energy efficiency;
- EDBs cannot, and should not try to, influence the number of customers that move into or out of the network area. The demand for connections is primarily driven by underlying economic conditions which encourage or discourage residential, commercial and industrial customers to locate in specific geographical locations;
- EDBs are limited in the ability to increase the share of distribution revenue recovered through fixed charges for residential customers. The *Electricity (Low Fixed Charge Tariff Option for Domestic Consumers) Regulations 2004* explicitly prohibit increasing the fixed charge for low users above $0.15 per day. This rate has been fixed since 2004 and therefore the share of revenue collected through fixed charges from these residential customers is declining. Approximately 64% of WELL's domestic customers are eligible to apply for the low fixed charge. Additionally, fixed charges cannot manage customer number risk; and

[7] For simplicity this example assumes that starting distribution revenue is $100M and there are no other factors contributing to changes in revenue across the period.

- EDBs cannot control or manage the extent to which the Commission's model over-estimates constant price revenue growth. For the 2012 mid-period reset the Commission's forecasts exceeded WELL's internal forecast of future growth and well exceeded WELL's actual growth. The impact of this forecasting difference over a five year period is demonstrated in figure 1 above.

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 constant price revenue growth forecasts. WELL considers that such an approach can be incorporated through the DPP determination without an amendment to the Input Methodologies. For example, a simple volume wash-up, known as the Q-factor, was applied by the Essential Services Commission of South Australia to the South Australian electricity distributor for the 2005-10 regulatory period.[8]

For future resets, the Commission should amend the IM's to replace the weighted average price cap with a revenue cap. This approach is consistent with regulators in other jurisdictions, including Australia and the United Kingdom, that 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.

5.2. Commission's constant price revenue growth model

For the mid-period DPP reset, the Commission developed a constant price revenue growth model which assumed that:

- Residential ICP growth is directly proportional to population growth;
- Residential demand growth was 0% per annum;
- The growth in revenue from industrial and commercial customers combined was a function of GDP growth.

The Commission then applied regional forecasts of population growth and GDP growth to estimate constant price revenue growth for each EDB.

Impact of model

WELL has analysed its actual data and compared this with the Commission model assumptions. There are two types of forecasting methodology flaws in the Commission's model which contributed to the over-estimation of WELL's constant price revenue growth. The first relates to forecasting of model inputs, specifically population growth and GDP growth. GDP growth in particular was significantly over-estimated for WELL. The Commission's model assumed 2.19% GDP growth per annum while actual GDP growth per annum was 0.70% over the first four years.[9] Furthermore, the Commission applied GDP forecasts for the entire Wellington region, however WELL's network does not cover all areas of the Wellington region including Featherston, Carterton, Masterton and the Kapiti Coast which have experienced different economic growth over the current regulatory period than WELL's network area due to their different economic drivers e.g. agricultural production.

WELL has re-calculated the Commission's model by replacing the forecast of population and GDP for the first four years of the regulatory period with the actual values where available and estimated values sourced from NZIER. The difference between the forecast and actual model inputs (population and GDP growth) contributed to 0.8% of the total 2.5% per annum difference between the Commission's forecast and WELL's actual constant price revenue growth. This leaves 1.7% per annum of difference, the majority of the difference, which was a result of the model not the inputs.

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[8] http://www.efa.com.au/Library/ESCOSA2005ElectricityDistributionPriceDetermination.pdf refer section 12.8.1.
[9] Wellington region GDP estimates sourced from NZIER.

Given that such a large proportion of the difference in the Commission's constant price revenue growth forecasts and WELL actual results was as a result of the model rather than the inputs, WELL considers that it is essential that the Commission revisit the assumptions behind its forecasting model to assess where the model assumptions are inconsistent with the data. It is important that the Commission test the model to ensure it is fit for purpose as the impact of over-estimating constant price revenue growth by say only 1% per annum would result in an under-recovery in revenue of 3% over five year regulatory period, valued at approximately 15M[10] for WELL.

Residential revenue growth

The Commission's model assumes that residential ICPs grow at the same rate as population growth. For WELL the annual average ICP growth over the four year period to 31 March 2014 was 0.16% while annual average population growth rate was 0.87% over the same period. WELL does not have access to the information for other EDBs to assess whether this is an industry-wide trend. Nevertheless, the Commission could request this residential ICP information from EDBs and use this data to estimate region-specific historic growth rates in ICPs. WELL considers that a region-specific historic average approach would provide a more accurate forecast of future residential ICP growth.

The Commission's model assumes that residential demand growth is flat at 0% growth per annum. For WELL, residential electricity consumption declined by an annual average of -2.83% per annum over the last four years. The trend in declining household consumption is being driven by increasing use of more energy efficient household appliances (e.g. LED lights) and increasing penetration of insulated housing and smart meter platforms allowing visibility of consumption. This reflects 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.[11] 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. Warmer ambient temperatures are also reducing the time residential properties are using electric heating. The trend in declining energy use per household is expected to continue through the 2015-20 DPP period as households continue to become more energy efficient. To ensure that this trend is adequately reflected in the constant price revenue growth model, the Commission should request information from EDBs to investigate the historical trends in household energy use by region and should apply these trends to estimate future residential consumption growth per household.

Industrial and commercial revenue growth

When the Commission modelled the relationship between GDP growth and industrial and commercial revenue growth for the 2012 mid-period reset it excluded:

- Information on the 13 Distributors that are not subject to DPP regulation. WELL considers that there is no theoretical or empirical reason to deliberately exclude exempt EDBs when the purpose of the analysis is to estimate relationships between GDP and revenue growth and these EDBs make up approximately 18% of New Zealand total ICPs and energy volumes; and

- Information on Vector, WELL and Orion. As a result the analysis excluded information on New Zealand's three major cities which make up approximately 44% of ICPs and 45% of total energy volumes in NZ.[12] Consequently the estimated relationship between GDP and commercial and industrial sector growth does not reflect the relationships observed in major cities.

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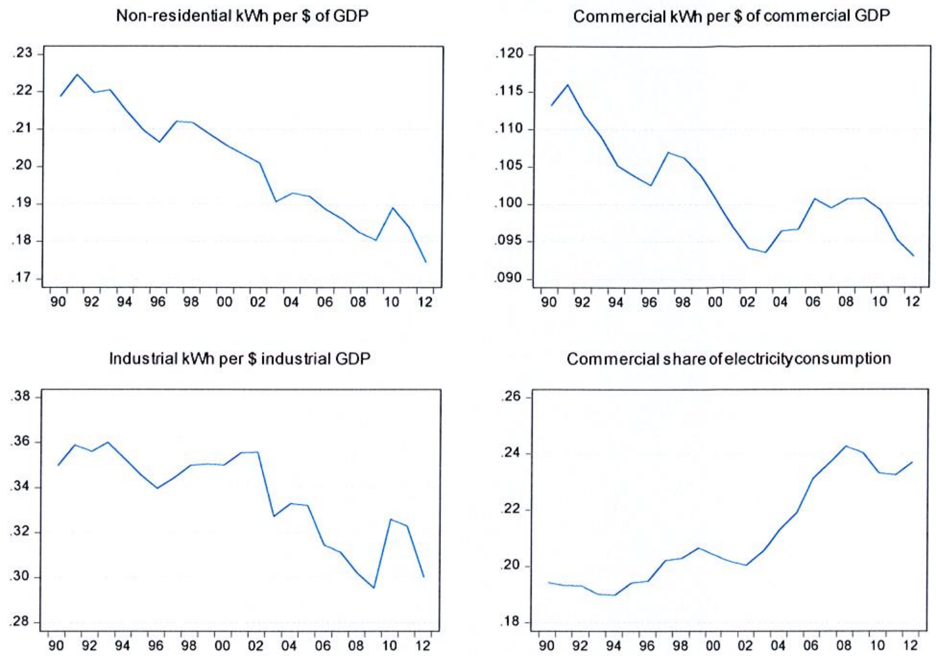
[10] Based on a starting level of distribution revenue of $100M per annum.

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

[12] Based on data reported in EDB's 2013 Information Disclosures.

The Commission's model does not take account of any forecast compositional shift between industrial and commercial activity. There is a long-term compositional shift in economic activity away from industrial activity towards commercial activity, and commercial customers are not a direct substitute for industrial customers. As shown in figure 2, 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 2, the relationship between the non-residential sector energy demand per $ of GDP is declining.

Figure 2: Energy consumption in Industrial and Commercial sectors



Source: Statistics NZ and Ministry of Business Innovation and Employment

<u>*Approach for 2015-20 DPP*</u>

For the 2015-20 DPP, WELL recommends that the Commission:

- Investigate the relationship between residential ICP growth and population growth by EDB region and apply to its constant price revenue model the EDB-specific historic average trend over the past five years;

- Investigate the trends in residential consumption per user by EDB region and apply to its constant price revenue model the EDB-specific historic average trend over the past five years;

- Investigate the relationship between commercial revenue growth and commercial GDP growth using regional data and apply to its constant price revenue model the EDB-specific historic average trend over the past five years;

- Investigate the relationship between industrial revenue growth and industrial GDP growth using regional data and apply to its constant price revenue model the EDB-specific historic average trend over the past five years.

To undertake this analysis the Commission should request information from EDBs on historical revenue by customer group (residential, commercial and industrial separately), ICPs by customer group and energy volumes by customer group. The Commission would also need to normalise the historical revenue data for the 2013/14 starting price adjustment. Alternatively the Commission could examine MWh growth as a proxy for real revenue growth, this would provide a reasonable approximation of the relationships given the large share of revenue which is sourced by EDBs through variable charges.

6. Term Credit Spread Differential Allowance

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 term credit spread differential allowance (**TCSDA**) disclosed by suppliers as an expense.

The IMs require that the TCSDA is calculated with reference to bond yields from the Bloomberg New Zealand 'A' fair value curve. This curve was not available in January and August 2013 when WELL issued debt which qualifies for a TCSDA, and the IMs do not contemplate the unavailability of this curve. It is important that the Commission address this issue prior to EDBs submitting the 2014 IDRs to ensure that the Commission has the correct information to include in the assessment of EDBs profitability for the 2015-20 DPP reset. The profitability of EDBs would not be assessed in accordance with the IMs if no expense was recognised in respect of debt which qualifies for a TCSDA.

WELL recommends that the same approach which applies to estimating the debt premium also apply to estimating the TCSDA where the Bloomberg New Zealand 'A' fair value curve is not available. This would mean estimating the terms V and X by applying IM clauses 2.4.4(3), 2.4.4(4) and 2.4.4(5) except that the tenor of debt for estimating the term V would be the tenor of the qualifying bond rather than five years. WELL would be happy to provide a worked example of how this approach could be applied for the purpose of WELL's 2013/14 IDR.

7. Quality standards and incentives

The Issues paper introduces the concept of replacing the current pass/fail mechanism for meeting the reliability standards with a financial incentive scheme. The issues paper also discusses how the reliability targets should be set and the normalisation process.

WELL considers that decisions regarding an incentive scheme, the reliability target and the normalisation process are a package and must be considered in combination. Importantly WELL considers that it is necessary to ensure that the quality targets and normalisation process are set appropriately before an incentive scheme can be applied. In particular, WELL considers that for the 2015-20 DPP:

- Quality targets should be based on SAIDI and SAIFI only. These measures are most valued by consumers and there is currently insufficient consistent data across EDBs to enable other quality metrics to be assessed in the 2015-20 period;

- Quality targets should be based on the historical SAIDI and SAIFI data over the past five years. WELL considers that the most recent past, i.e. past five years, provides the best estimate of EDBs currently achievable quality standards. This reflects current network performance and current expenditure levels required to meet the current level of performance. The application of an incentive scheme from 1 April 2015 would then move EDBs toward an efficient level of quality standards over time. WELL does not support quality targets based on the current limits for the 2010-15 DPP reset. The current limits were derived based on quality performance over the 2004-09 period which is no longer representative of the current state of the network, current expenditure levels, and current weather patterns;

- Quality targets should be based on the mean plus one standard deviation using historical SAIDI and SAIFI data over the past five years. WELL does not agree that the current approach incentivises poor reliability. WELL notes that the increase in outages on the WELL network over the past five years has been as a result of external extreme weather events beyond WELL's control and is not a result of poor asset management and does not reflect a reduction in the underlying performance capability of the WELL network;

- Quality targets should place more weight on unplanned relative to planned outages to reflect the greater impact on customers from unplanned compared to planned outages;

- The normalisation process should be simplified such that it does not inadvertently penalise suppliers with a large number of zero outage days. WELL's current boundary value is disproportionately high compared to its limits as demonstrated in table 2 below. As a result of the current normalisation rules, which require replacement of daily values which exceed the boundary with the boundary value, WELL has been unable to achieve the reliability limits during the current period primarily as a result of repeated extreme weather events. The Commission should review the normalisation method such that daily SAIDI and SAIFI values which exceed the boundary value are replaced with either a zero value or average daily value; and

Table 2: WELL's current SAIDI and SAIFI limit and boundary value

Reliability measure	Limit	Boundary value
SAIDI	40.74	9.72
SAIFI	0.60	0.24

- The normalisation process should also be amended to ensure that major events which span multiple days causing multiple individual outages are able to be normalised and treated as a single event. This is particularly important when the daily impact of the outages fails to meet the boundary value on each day of the multi-day event. This is necessary to ensure that EDBs are not penalised multiple times for the same extreme event. In Australia should an event exceed the boundary, the entire event is excluded from the performance assessment.

Ensuring that the normalisation process is working effectively and the targets are set to reflect current network performance based on current weather conditions is particularly important as weather events become more frequent and extreme. A study by Climate Central of US power utilities demonstrates that outages in the US are rapidly increasing due to extreme weather events occurring more frequently and with greater intensity. The study shows between 2003 and 2012 weather related outages have doubled and caused 80% of all outages over the same period.[13] Refer to attachment B of this submission.

Subject to the quality targets and normalisation process being set to address WELL's concerns noted above, WELL would support further exploring the introduction of a financial incentive scheme which replaces the current pass/fail mechanism. In developing a quality incentive scheme the Commission should take into account the following:

- The introduction of a quality incentive scheme should be implemented at a relatively low incentive level initially to enable testing of the appropriateness of the scheme before applying a strong incentive which results in EDBs having a higher level of revenue at risk. A lower revenue at risk is also more appropriate if reliability outcomes relative to the targets are driven primarily by adverse weather events rather than underlying network performance;

- Given a particular percent of revenue at risk, applying a large (smaller) incentive rate would only have the effect of reducing (increasing) the range of reliability outcomes which are captured within the incentive scheme. Therefore the appropriate incentive rate to apply depends very much on the level of risk applied. The incentive rate could relate to a national value of lost load which can simply be applied across all EDBs and all customer types;

- Any quality incentive scheme should include a banking scheme which allows EDBs to recover/return the financial gains/losses incurred under the scheme through line charges either 2 or 3 years after the year in which the gain/loss is realised.[14] This type of banking scheme is employed under the Service Target Performance Incentive Scheme (**STPIS**) in Australia and is necessary to enable smoothing of electricity prices to consumers and to assist EDBs to manage revenue fluctuations;

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[13] Climate Central, '*Blackout: Extreme Weather, Climate Change and Power Outages*', 2014.

[14] Gains and losses cannot be recovered/returned in the year directly after being realised due to the next years prices being set in advance of the final reliability outcomes being known.

- It is appropriate to apply the WACC as the time value of money applying to the delay in recovery/return of losses/gains realised under the scheme. The WACC should be the WACC that applied in the regulatory period during which the gain/loss was realised;

- It is not necessary to include an enforcement threshold as well as an incentive scheme. This is because the incentive scheme results in automatic financial penalties on EDBs that exceed the quality targets. The financial penalties will provide 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 Australian Energy Regulator's (**AER**) STPIS regime does not include an enforcement threshold and six years after the scheme was introduced the AER has not found it necessary to consider introducing an enforcement threshold. WELL recommends that the Commission not include an enforcement threshold for the 2015-20 DPP. The Commission could review this position during the following DPP reset if experience demonstrated that an enforcement threshold was necessary; and

- A simplified version of the methodology employed in the AER's STPIS scheme should be applied. The STPIS was introduced in 2009 and is continuing to be applied by the AER as it progressively resets the five yearly regulatory determinations applying to EDBs in different states across Australia.

WELL considers that the Commission should undertake further consultation on its proposed incentive scheme once it is more developed but prior to publishing the draft decision on the DPP. This is necessary to provide stakeholders with a better opportunity to contribute to the development of the scheme.

8. Managing uncertainty and risk

8.1. Forecasting pass through and recoverable costs

The current DPP formula requires EDBs to forecast third party costs including transmission charges, levies payable to the Commission, Electricity Authority, Electricity and Gas Complaints Commissioner Scheme, rates payable to local councils and Avoided Costs of Transmission payments (collectively known as pass through and recoverable costs). These charges contribute to approximately 38% of WELL's total line charge revenue.

The current DPP does not allow for any true-up of forecasting error in these third party costs. Consequently, EDBs are at risk of either breaching the DPP price path if these costs are over-forecast or failing to adequately recover third party costs if the costs are under-forecast.

In response to WELL's price path breach in 2011/12, which resulted from unintentional over-forecasting of third party costs, the Commission required that WELL compensate customers for the over-recovery based on the actual value of the over-recovery plus the time value of money based on the Weighted Average Cost of Capital (**WACC**).[15] The Commission stated that it would not take into consideration EDBs prior years under-recoveries due to under-forecasting of third party costs. As previously advised to the Commission, such an approach to compliance results in an asymmetric forecasting risk to EDBs in relation to third party costs. Particularly since the Commission has stated that it is likely to take court action against EDBs that breach a second time.

WELL considers that it is inappropriate for EDBs to bear the asymmetric risk of mis-forecasting third party costs. Third party costs are beyond the control of EDBs and some third party costs do not change at a predictable rate over time, which makes forecasting difficult. For example some third parties have amended their methods for calculating charges and/or periodically invoiced wash-ups from subsequent year over or under-charges.

True-up arrangements for forecasting error in relation to third party costs are applied by the AER and by the Commission in the DPP applicable to gas distribution networks.

[15] In 2011/12 WELL over-recovered $117K due to over-forecasting third party costs. This is equivalent to 0.1% of revenue or $0.71 per customer connection. In accordance with its settlement agreement with the Commission WELL reduced its 2014/15 revenue by $148K to compensate consumers for the unintentional over-recovery plus the time value of money based on the regulated WACC of 8.77% per annum.

WELL recommends that the Commission introduce a simple true-up mechanism into the DPP formula which:

- Provides for an automatic adjustment to the allowable revenue two years subsequent to the year in which either over or under-forecasting of third party costs occurred. A one year delay is necessary due to the prices for the following year being set before all third party costs for the current year are finalised;
- Sets the adjustment equal to the value of the over- or under-recovery resulting from the mis-forecasting of third party costs plus the time value of money; and
- Applies the WACC as the time value of money for both under- or over-recoveries. If any other time value of money is applied then there will be perverse incentives to systematically either over- or under-forecast third party costs which WELL considers contrary to the purpose of a true-up mechanism. The WACC should be the WACC applied in the regulatory period during which the gain/loss was realised.

WELL does not support the true-up mechanism applied in the gas distribution DPP. This mechanism is complicated as it requires determining which costs are ascertainable and some which are initially considered ascertainable can still change. It also results in an ongoing delay and consequential permanent under-recovery of one year of third party costs which are not ascertainable. For EDBs, third party costs are significantly larger than for gas pipelines and therefore it is necessary to apply a simple approach which ensures all third party costs are fully recovered but not over-recovered.

8.2. Managing demand and catastrophic risk

The Issues paper states that the Commission does not consider that EDBs should be compensated for lower than forecast revenue resulting from either lower than forecast energy demand or catastrophic events.

In relation to energy demand risk resulting from anomalies in the Commission's constant price revenue growth model, as discussed in section 5, EDBs cannot and should not attempt to, influence energy demand by customers or the geographic location of customers in order to mitigate forecasting differences in the Commission's constant price revenue growth model. These decisions will be driven by underlying economic and social conditions. Furthermore, network costs are not related to total energy throughput and energy efficiency should be promoted not discouraged by the regulatory regime in accordance with section 54Q of the *Commerce Act 1986*. Therefore, WELL considers that the Commission should introduce a wash up into the price-path formula to correct for significant variances in its constant price revenue growth forecasting.

WELL considers that the basis for the Commission's 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 states that well 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.[16] However, 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;

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16 Issues paper, page 40.

- Catastrophic risk borne by regulated suppliers must either be compensated for ex post or ex ante. This is consistent with competitive markets where risks are managed by suppliers through insurance policies or self-insurance and suppliers pass on the costs to customers. Professor Yarrow noted that:[17]

  "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."

- The WACC does not include compensation for asymmetric catastrophic risk. In the final reasons paper for its final WACC IM Determination the Commission stated that: [18]

  "The IM does not make any adjustments to the cost of capital for Type 1 asymmetric risk."

EDBs must be compensated for catastrophic risk and since the Commission did not allow an ex post recovery for Orion, the Commission must provide an ex ante allowance to cover the costs to EDBs of mitigating catastrophic risk. As noted in section 3, WELL recommends that this is achieved through an increase in the opex allowance for the 2015-20 DPP.

9. Incentive schemes

9.1. Expenditure incentives

WELL supports the introduction of symmetrical financial incentive schemes for both opex and capex for the 2015-20 DPP. WELL considers that including expenditure incentive schemes as part of the DPP framework is an important step for giving additional confidence to the Commission that EDBs costs are efficient. Incentive schemes should be designed to provide sufficient incentives for EDBs to seek cost efficiencies at any time during the regulatory period as they will share in the benefit of making these efficiencies through temporarily retaining the value of the cost savings. WELL looks forward to participating in the Commission's consultation on the introduction of incentive schemes for the 2015-20 DPP.

9.2. Energy efficiency incentives

For the 2015-20 DPP, WELL supports the introduction of energy efficiency initiatives including a scheme that includes:

- A mechanism to offset revenue losses resulting from energy efficiency initiatives, similar to the D-factor applied in Australia but which provides for ex ante assurance of revenue recovery;

- An ex ante allowance for investigating energy efficiency initiatives, similar to the Demand Management Incentive Allowance that is employed in Australia. Any unutilised allowances could be returned in the following regulatory period;

- A clear provision for non-network solutions to be included in the regulatory asset base. The non-network solutions would be those that provide lower cost mechanisms for managing demand and replace or defer traditional network investments. Large scale non-network solutions could be implemented by EDBs if the impact of such investments on revenue was neutral;

- Ensuring that the depreciation allowance reflects the expected life of these assets rather than the current 45 year life assumption which dis-incentivises investment in shorter-life assets. This is discussed in more detail in section 4.3 in relation to non-network assets.

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

[18] Commerce Commission, '*Input Methodologies (Electricity Distribution and Gas Pipeline Services) Reasons Paper*', December 2010, paragraph H12.13.

WELL considers that it is essential that the Commission implements an energy efficiency scheme which addresses the current disincentives for EDBs to participate in energy efficiency and demand management initiatives for the 2015-20 DPP. A delay in introducing such a scheme would result in missed opportunities for New Zealand to become more energy efficient.

As discussed in section 5 and in WELL's letter to the Commission dated 21 February 2014, WELL recommends that a revenue cap is introduced during the IM review in 2017 and applied for future DPP resets. If a revenue cap is introduced then the D-factor scheme would no longer be required.

10. Closing

WELL appreciates the opportunity to provide a submission on the Issues paper and would welcome the opportunity to discuss with the Commission any of the matters raised in this submission.

WELL encourages the Commission to maintain an open dialogue with stakeholders regarding its progress in assess and developing the methods it intends to apply for the 2015-20 DPP reset.

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

Yours sincerely

G Skelton

Greg Skelton
CHIEF EXECUTIVE OFFICER

Attachment A

The following scenarios demonstrate that when an opex incentive scheme is in place, applying a historical average approach to set base opex allowances for future regulatory periods will distort EDBs incentives regarding when in the regulatory period to make opex efficiency savings.

These scenarios assume:

- An incentive scheme similar to the IRIS applicable to CPPs is in place;
- For simplicity, there is no escalation to opex allowances for input costs, scale changes or step changes.

Scenarios 1-5 demonstrate that when the average of actual opex in years 3 and 4 of period 1 is used to set period 2 opex allowances, the total profit from making efficiency gains is higher if EDBs wait until year 4 to make the efficiency gain.

Scenarios 6-10 demonstrate that when only actual opex in year 4 of period 1 is used to set period 2 opex allowances, total profit from making efficiency gains is the same in every year of the regulatory period.

Scenarios 1-5 demonstrate the total allowance including IRIS benefit when the average of actual opex in years 3 and 4 in period 1 is used to set period 2 opex allowances											
Scenario 1: Efficiency saving in year 1											
	Period 1					Period 2					Total Profit
Year	1	2	3	4	5	1	2	3	4	5	
Allowance	100	100	100	100	100	90	90	90	90	90	
Actual spend	90	90	90	90	90	90	90	90	90	90	
IRIS benefit						10	0	0	0	0	
Opex allowance plus IRIS benefit	100	100	100	100	100	100	90	90	90	90	
Revenue less actual spend	10	10	10	10	10	10	0	0	0	0	60

Scenario 2: Efficiencysaving in year 2											
	Period 1					Period 2					Total Profit
Year	1	2	3	4	5	1	2	3	4	5	
Allowance	100	100	100	100	100	90	90	90	90	90	
Actual spend	100	90	90	90	90	90	90	90	90	90	
IRIS benefit						10	10	0	0	0	
Base allowance plus IRIS benefit	100	100	100	100	100	100	100	90	90	90	
Revenue less actual spend	0	10	10	10	10	10	10	0	0	0	60

Scenario 3: Efficiency saving in year 3											
	Period 1					Period 2					Total Profit
Year	1	2	3	4	5	1	2	3	4	5	
Allowance	100	100	100	100	100	90	90	90	90	90	
Actual spend	100	100	90	90	90	90	90	90	90	90	
IRIS benefit						10	10	10	0	0	
Base allowance plus IRIS benefit	100	100	100	100	100	100	100	100	90	90	
Revenue less actual spend	0	0	10	10	10	10	10	10	0	0	60

Scenario 4: Efficiency saving in year 4											
	Period 1					Period 2					Total Profit
Year	1	2	3	4	5	1	2	3	4	5	
Allowance	100	100	100	100	100	95	95	95	95	95	
Actual spend	100	100	100	90	90	90	90	90	90	90	
IRIS benefit						10	10	10	10	0	
Base allowance plus IRIS benefit	100	100	100	100	100	105	105	105	105	95	
Revenue less actual spend	0	0	0	10	10	15	15	15	15	5	85

Scenario 5: Efficiency saving in year 5											
	Period 1					Period 2					Total Profit
Year	1	2	3	4	5	1	2	3	4	5	
Allowance	100	100	100	100	100	100	100	100	100	100	
Actual spend	100	100	100	100	90	90	90	90	90	90	
IRIS benefit											
Base allowance plus IRIS benefit	100	100	100	100	100	100	100	100	100	100	
Revenue less actual spend	0	0	0	0	10	10	10	10	10	10	60

Scenarios 6-10 demonstrate the total allowance including IRIS benefit when only actual opex in year 4 in period 1 is used to set period 2 opex allowances											
Scenario 6: Efficiency saving in year 1											
	Period 1					Period 2					Total Profit
Year	1	2	3	4	5	1	2	3	4	5	
Allowance	100	100	100	100	100	90	90	90	90	90	
Actual spend	90	90	90	90	90	90	90	90	90	90	
IRIS benefit						10	0	0	0	0	
Opex allowance plus IRIS benefit	100	100	100	100	100	100	90	90	90	90	
Revenue less actual spend	10	10	10	10	10	10	0	0	0	0	60

Scenario 7: Efficiency saving in year 2											
	Period 1					Period 2					Total Profit
Year	1	2	3	4	5	1	2	3	4	5	
Allowance	100	100	100	100	100	90	90	90	90	90	
Actual spend	100	90	90	90	90	90	90	90	90	90	
IRIS benefit						10	10	0	0	0	
Base allowance plus IRIS benefit	100	100	100	100	100	100	100	90	90	90	
Revenue less actual spend	0	10	10	10	10	10	10	0	0	0	60

Scenario 8: Efficiency saving in year 3											
	Period 1					Period 2					Total Profit
Year	1	2	3	4	5	1	2	3	4	5	
Allowance	100	100	100	100	100	90	90	90	90	90	
Actual spend	100	100	90	90	90	90	90	90	90	90	
IRIS benefit						10	10	10	0	0	
Base allowance plus IRIS benefit	100	100	100	100	100	100	100	100	90	90	
Revenue less actual spend	0	0	10	10	10	10	10	10	0	0	60

Scenario 9: Efficiency saving in year 4											
	Period 1					Period 2					Total Profit
Year	1	2	3	4	5	1	2	3	4	5	
Allowance	100	100	100	100	100	90	90	90	90	90	
Actual spend	100	100	100	90	90	90	90	90	90	90	
IRIS benefit						10	10	10	10	0	
Base allowance plus IRIS benefit	100	100	100	100	100	100	100	100	100	90	
Revenue less actual spend	0	0	0	10	10	10	10	10	10	0	60

Scenario 10: Efficiency saving in year 5											
	Period 1					Period 2					Total Profit
Year	1	2	3	4	5	1	2	3	4	5	
Allowance	100	100	100	100	100	100	100	100	100	100	
Actual spend	100	100	100	100	90	90	90	90	90	90	
IRIS benefit											
Base allowance plus IRIS benefit	100	100	100	100	100	100	100	100	100	100	
Revenue less actual spend	0	0	0	0	10	10	10	10	10	10	60