Submission to the Commerce Commission

on

Default price-quality paths from 1 April 2015 for 17 electricity distributors: Process and issues paper

PwC submission on behalf of group of 20 EDBs

30 April 2014

Made on behalf of 20 Electricity Distribution Businesses

Table of contents

Submission on DPP Reset: Process and Issues Paper

1. This paper forms our submission on the Commerce Commission's (Commission) paper, "Default price-quality paths from 1 April 2015 for 17 electricity distributors: Process and issues paper" released on 21 March 2014 (the Paper). This submission has been prepared by PricewaterhouseCoopers (PwC) on behalf of the following 20 Electricity Distribution Businesses (EDBs or distributors):

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

2. Together these businesses supply 28% of electricity consumers, maintain 46% of total distribution network length and service about 73% of the total network supply area in New Zealand. They include both consumer owned and non-consumer owned businesses, and urban and rural networks located in both the North and South Islands.

3. The Paper addresses the process for resetting the DPP applying to 16 non-exempt EDBs from 1 April 2015, and a number of topics relevant to that reset. It is proposed that Orion New Zealand is not included in the DPP reset at this time, due to its recent CPP Determination.

4. It is proposed that similar methods are applied in resetting the price path as applied in the 2012 DPP decision[1], while targeting improvements in certain areas, if the price path is to be set with reference to current and projected profitability. It is proposed that potential areas for consideration include the approach to determining:

- expenditure forecasts
- revenue growth forecasts
- rates of change in prices
- enhanced incentives for performance improvement
- treatment of uncertainty and catastrophic risk
- recovery of outstanding claw-back arising under the 2012 DPP Determination
- treatment of assets purchased from Transpower.

5. Quality paths were not reset in 2012, and the current approach has applied for the full five year regulatory period. The Paper proposes a new approach to setting the DPP quality paths.

6. We agree in principle that improvements and refinements could be introduced for the next regulatory period, in particular to address issues which have emerged or learnings from the current regulatory period. We are cautious, however, about introducing substantial changes, where these have not been fully tested or where insufficient or inadequate information is available to implement them, or to understand the likely consequences of them during the next regulatory period.

7. This submission presents the views of the 20 EDBs listed above, on the issues identified in the Paper.

8. We also note and support the Electricity Network Association's (ENA's) submission on the Paper. In addition, we support the ENA's working group initiatives which have contributed considerable research to key issues for the DPP reset, and encourage the Commission to fully consider the working group recommendations as it proceeds with the development of the approach to resetting the DPP for the next regulatory period.

[1] Electricity Distribution Default Price-Quality Path Determination 2012

Expenditure forecasting

9. The Paper sets out a number of proposals for forecasting operating and capital expenditure for the purpose of resetting the price path. Our specific comments in relation to the proposals are set out below.

10. We also note and support the work of the ENA opex and capex forecasting working group, including the three output papers that Frontier Economics has produced on behalf of this group. We note that the working group's recommendations include both short and long-term options, recognising that there is limited time before the next regulatory period commences, and that some of the options are not considered practical to implement at this time. We support this cautionary recommendation.

Opex forecasts

11. In the Paper it is proposed that a similar forecasting approach to that applied in the 2012 DPP reset is used for determining opex allowances for each EDB. That is, opex forecasts will be set with reference to base year expenditure escalated forward for changes in network scale, partial productivity and input prices.

12. We support the proposal to adopt a similar approach to forecasting opex. However, we make a number of comments as to how this may be implemented in the following paragraphs.

Base year opex

13. One of the key issues identified with the proposed approach is whether more than one year of data should be used to determine base year opex. As a general principle, we submit that base year data should include recent opex information because it better reflects current operational and structural arrangements, recent productivity improvements, actual input costs and current network scale. For these reasons, we submit that FY14 information should be used as this is the most recent view of opex.

14. FY13 data could also be used by combining it with FY14 data, to potentially offset abnormalities that may exist in a single year of data. However, if FY13 data is to be used it needs to be adjusted for scale effects and input cost inflation.

15. We do not consider data prior to FY13 to be relevant, as it is not current enough, and there is a disjoint in the disclosure dataset prior to FY13, particularly in regard to related party opex and cost allocation.

Network scale effects need to be tested

16. The Paper provides little insight into the econometric modelling approach which may be adopted to project forward opex allowances for each EDB. We submit that in order to improve the robustness of network scale assumptions, ex-post analysis should be undertaken to determine how effective the approach adopted in 2012 was at predicting actual opex.

17. We also consider that installed capacity is a critical indicator of network scale. A number of networks, particularly in rural areas, are experiencing demand for increased connection capacity, with little or no change in network length or the number of connections.

18. These additional demands on the network translate into higher opex as customer needs become more sophisticated and larger capacity assets are subject to more frequent inspection and maintenance regimes. We consider that the 2012 approach disadvantages these networks, relative to those who experience the majority of their growth via network extensions and new connections.

19. The Paper proposes that step changes in opex (similar to the insurance allowance permitted in 2012) could be introduced if certain criteria are met. We do not consider that there are discrete and quantifiable opex costs across the sector that meet the thresholds proposed. Notwithstanding this, we

do consider that there are on-going pressures on opex which require increased budgets and refinements to systems and processes. Health and safety, risk management (including insurance and seismic strengthening), traffic management, compliance reporting (including Part 4 obligations), and industry regulation (ie changes to pricing and use of system agreement regulations) are all examples of areas where additional resources are currently being directed.

20. We also note that some networks experience very little growth. The current model implies opex allowances are effectively constant in real terms, before any productivity adjustments for networks with little growth. We consider that the above cost pressures are particularly difficult for the networks with little growth, as revenues are static, and accordingly funds must be diverted from other activities in order to meet these new demands. The proposed opex forecasting approach perpetuates this cycle.

Capex forecasts

21. The Paper proposes that the approach to forecasting capex is revised in favour of either:

    a) low cost econometric models to independently forecast capital expenditure

    b) a cap on supplier forecasts, similar to that applied in setting the current GDP DPP price path.

22. With regards to a), it is suggested that different approaches could be applied to different categories of capex, and the cap approach could also potentially be applied to residual categories where no alternative approach is developed. If option a) is applied it is proposed that the categories of capex that are the most material will be the key focus for independent modelling.

Low cost models are unlikely to be capable of replicating robust AMP processes

23. We have several reservations on the use of econometric models for forecasting capex under option a).

24. In particular, this presupposes that a top-down econometric model is materially better at forecasting future expenditure than the bottom-up AMP processes undertaken by the engineers with intimate knowledge of their own networks.

25. While we understand the intent to develop alternative models, particularly in relation to either asset replacement and renewal, system growth or consumer connection capex, we consider that it is too late to develop these models. The Draft Decision stage is too late to make these models available for the first time for consultation.

26. If alternative models are to be developed, then we consider that the outputs should only be used as cross checks on EDB capex forecasts for this next regulatory period or to inform the selection of a capex cap (as discussed below).

27. We understand that the proposed replacement and renewals model is to use the expanded dataset disclosed under the 2012 IDD. Much of the relevant data was disclosed for the first time in conjunction with AMPs for the planning period commencing 1 April 2013 (by the end of March 2013) with supplementary data disclosed prior to the end of August 2013.[2] Updated forecast data has since been disclosed prior to the end of March 2014. We assume disclosure data will also provide the key inputs into the proposed modelling of system growth and connection capex.

28. Thus we do not consider that data availability could have constrained the development of the proposed models.

---

[2] We note some EDBs disclosed slightly later than the 31 August 2013 deadline, however the latest disclosures were made by exempt EDBs, ie: not subject to the DPP.

29. The Paper highlights a number of challenges for developing top down capex forecasting models of the types proposed. We include comments on these topics in the following paragraphs.

Replacement capex models

30. Age based survivor models require unit replacement costs by asset type. The asset types currently reported in ID disclosures are aggregated asset categories, each comprising a number of different 'types' of asset (eg: cable or conductor by size, transformers or switchgear by size and with different functionality). If unit costs were derived, they would need to be an amalgam of the different assets captured within each 'type' and the mix would differ for each EDB, and across different years (based on age profiles). Further, our experience with developing valuation handbooks shows that it is a complex process to derive unit replacement costs which are fit for purpose. The 2004 ODV Handbook consultation ran for about a year, and one of the key challenges was developing the unit costs, and relevant locational adjustment factors.

31. The ODV Handbook replacement cost data is not an appropriate basis for replacement cost modelling because it reflects estimated costs for wholesale replacement of the network, with deductions to actual unit costs for hypothetical efficiencies associated with large scale replacements. Further the 2004 Handbook is now ten years old. The ENA prepared a more up to date version in 2010, however this was prepared using the same valuation principles as the 2004 Handbook. These valuation handbooks also have a different way of categorising asset classes to the ID datasets.

32. Based on the description provided we assume that the replacement capex model would assess each asset type independently, and would be independent of planned maintenance or system growth, or asset relocation activity. In reality, where possible, EDBs optimise their lifecycle costs by co-ordinating their replacement projects with other projects, and by avoiding piecemeal replacements which are high cost and disruptive.

33. Asset age information reflects the information currently available to EDBs, and as disclosed there are instances where information is missing and/or default or estimated ages have been applied. Thus the recorded age may differ to the actual age, and the service potential of the asset is not likely to be fairly represented by its calculated remaining life. This is why assets are generally inspected before a decision to maintain or replace is made.

34. Distribution planners don't typically use normal distribution curves when considering asset failure, as typically demonstrated in AMPs.[3]

35. There will be variability between networks and over time, and as acknowledged in the Paper, this may be more pronounced for smaller networks. We therefore consider it is useful to assess from an industry wide perspective (ie incorporating data from exempt and non-exempt EDBs) what the forecast renewals capex (and related opex) is expected to be, how this relates to historical levels, and what the age and condition data now disclosed tells us about industry wide renewals forecasts. However, we consider this should be limited to information purposes for the foreseeable future, with a view to possibly influencing the 2020 DPP reset. Any such analysis completed prior to the DPP Draft Decision should only be used as a cross check on the EDB's own forecasts, for the purpose of evaluating a capex cap.

System growth capex models

36. We consider that the case for building a top down model to predict future system growth capex is significantly weaker than for asset replacement for the reasons set out paragraphs B30-B42 of the Paper. This applies to both DPP price path setting purposes, and in relation to ID summary and analysis. The complexity, number of assumptions that would need to be made, variability within networks and over time, and unique solutions that are developed to address each network constraint

[3] For example, failure rates often follow a 'bathtub curve' profile, meaning failure rates are the greatest at the beginning and end of the life of an asset.

are reasons this type of modelling does not appear to be a cost effective option in the New Zealand context.

37. We note that, similar to our comments in relation to replacement cost models above, the ODV Handbook unit costs were not developed for this type of predictive capex forecasting. Further, given the unique nature of capacity investments, unit costs are not included in the ODV Handbooks for core assets such as zone substations.

38. We consider a far better approach is to consider the information provided in support of system growth capex plans in AMPs, which we observe is generally the most detailed component of the capex plan in an AMP. This is because AMPs identify the problem or constraint, and consider the options for solving the constraint.

Consumer connection capex models

39. The Paper proposes that predictive models are developed using forecasts of population growth and demand. It is not clear why it is considered in paragraph B47 that future demand growth is likely to be relatively constant. EDBs provide demand forecasts in their disclosures. We consider that this is a better option than arbitrarily assuming all demand growth is constant.

40. As stated earlier, we consider investment in new and upgraded capacity are also important considerations as existing customers may choose to increase the capacity of their existing connections.

41. Further, the level of capital contributions would need to be assessed, as it is the net capex which is relevant for the price path.

42. Given the relatively minor nature of net connection capex, we do not consider that development of a top down model for this category of capex is a priority for this reset.

Support for use of caps on supplier AMP forecasts

43. Given the time available we support the proposal to use supplier's own forecasts derived from AMP forecasting and planning processes (which now include both network and non-network expenditure). We support a cap to set an upper limit on variation from historical levels of capex. However, in applying this cap we consider that adjustments should be made for network scale and changes in input prices.

44. In setting GDB price paths, a 120% cap on average network and non-network capex was applied to the four and a quarter year forecast DPP period relative to average actual capex from 2008-2011. The rationale for the cap was set out in Attachment B of the accompanying Reasons Paper, as follows:

> *"For distribution businesses the 20% limit reflects the typical year-on-year fluctuations in capital expenditure. The 20% cap is equivalent to the combined effect of an increase of 5% per year for each of the four years of this regulatory period...In our view the 20% limit will generally provide for 'business as usual' levels of investment, but not large scale investments."*[4]

45. Applying a similar approach to non-exempt EDBs implies a cap of approximately 135%, or 130% excluding Orion. These figures are derived as follows:

    - 2010-2013 capex (nominal) is sourced from schedule 5h(v) and 6a(i) of 2013 information disclosures for each non-exempt EDB
    - disclosed amounts are expressed in constant 2013 dollars using the capital goods price index

[4] Paragraph B10, Setting Default Price-Quality Paths for Suppliers of Gas Pipeline Services, 28 February 2013

- the average annual change in total annual capex (ie of all non-exempt EDBs) within this period is calculated to be 7%, or 6% excluding Orion
- this is multiplied by 5, consistent with the 5 year DPP regulatory period to determine an implied capex cap.

46. See appendix A for working. We believe that the cap could be set with reference to actual average variation across the 2010-2014 period using information disclosures.

47. Non-network capex is much less significant relative to network capex (ie only 5.4% of forecast total capital expenditure for all EDBs between FY14-FY23). Despite this, non-network capex is often lumpy, and one-off investments in major non-network assets such as land, head office buildings, or IT systems is not uncommon. These one-off expenditure items can represent a large proportion of non-network capex within a particular year, an issue that is likely to disproportionately affect smaller EDBs. As an example, Orion New Zealand and MainPower have both been required to build new head offices resulting from damage to existing sites incurred during the Canterbury earthquakes. In both cases, these costs quadruple non-network capex in the relevant year. While this expenditure relates to an extreme event, it highlights the magnitude of variation that can legitimately occur. Given these features, we submit that a cap should be applied to aggregate network and non-network capex.

Other forecast assumptions

Input price indices

48. We refer to Frontier Economics' Output 1 and Output 3 reports, submitted on behalf of the ENA, which include consideration of input price information for deriving expenditure forecasts. In particular, we note the availability of more relevant sub-sector input price indices, which we have previously submitted are more relevant than economy wide indices, for setting price paths.

49. We also note that the global economy is undergoing unpredictable recovery from the GFC, which potentially creates greater uncertainty in many of the underlying inputs relevant to electricity distribution input price indices (eg the exchange rate and raw material prices). Given this uncertainty we submit that input price inflation data is selected that is:

    - sourced from robust analysis
    - sourced from the most recent information available
    - corroborated by more than one independent source, where possible
    - relevant to the input price pressures that electricity distributors face.

Allowable rates of change

50. It is proposed that the X-factor is updated for the next regulatory period, and is to be derived using total factor productivity analysis. In addition, opex and capex partial productivity estimates are to be derived for the purpose of establishing opex and capex forecasts using the current and projected profitability option. Economic Insights has been engaged by the Commission to determine these estimates.

51. We note and support the work of the ENA on this topic, who have engaged an independent expert to conduct parallel analysis to Economic Insights.

52. For the 2012 DPP price path, an opex partial productivity factor of 0% was adopted. In the Paper it is suggests that there has been a temporary decline in opex partial productivity, due to a temporary decline in demand.

53. We acknowledge the recent decline in both electricity peak demand and consumption. This trend started in 2008 around the same time as the GFC. While this may appear to be a temporary response to falling economic output, we note that electricity consumption is continuing to fall, even as New Zealand's real GDP rebounds. This suggests a structural change in electricity usage since 2008 which may go beyond a simple response to the economic downturn. We consider that one possible explanation is that electricity demand growth may remain persistently low.

54. Anecdotally it has been suggested that this is partly due to investments in energy efficiency initiatives (eg home insulation schemes and more efficient appliances) and more energy efficient building practices for new homes. Continuing retail energy price increases have also incentivised users to find ways to conserve energy.

55. Accordingly, we suggest that any structural changes in electricity usage need to be accounted for, and not unduly dismissed, in any modelling of partial productivity.

56. Further, we submit any recommendations for productivity adjustments to capex and opex allowances should be tested against the quantum of the capex or opex allowance across the entire regulatory period. This is necessary to ensure that any assumed productivity changes are reasonable in light of the opex and capex contributions to BBAR, and MAR.

Quality paths

57. Section 4 of the Paper sets out high-level proposals for setting quality standards. In particular, it is proposed that a quality incentive scheme is introduced to replace the current pass/fail approach.

58. We note and support the work of the ENA's Quality of Supply and Incentives (QoSI) working group in assessing how quality may be assessed and measured and possible refinements to the quality path approach for the DPP. Our further comments are provided below.

Reliability measures

59. We support the continued use of Class A and Class B SAIDI and SAIFI as the primary measure of quality for the DPP. While we acknowledge that the QoSI working group also highlighted that customer service and power quality were highly valued by consumers, we note that:

    - Customer service is addressed in contractual terms, such as in non-standard arrangements (ie higher restoration standards) or in upfront capital contributions (ie for specialist equipment of connection redundancy). These arrangements are transparently disclosed under clause 2.4 of the IDD.
    - Other indicators of customer service are currently assessed in multiple ways across the sector, and there is no consistent and robust baseline data available which is suitable for DPP purposes.
    - Power quality is largely regulated at a system level by common quality standards under the Electricity Industry Participation Code as administered by the system operator. In addition, on investigation it is common for the source of power quality complaints to be outside the distribution network or outside the responsibility of the network owner or operator. Furthermore, many EDBs seek to reduce power quality issues on the network through their pricing structures (ie power factor charges).

60. There is also considerable history in disclosing SAIDI and SAIFI information which affords these metrics a number of advantages over other alternatives, including:

    - a long time-series of audited data for all non-exempt EDBs which can be used to establish an appropriate baseline
    - the development of robust internal processes and procedures for recording, calculating and reporting reliability performance.

61. We submit that if additional quality measures are to be introduced into the DPP that they first be adopted into information disclosures for a reasonable period so that the same advantages of history can be applied in setting quality standards. This is particularly important if there is to be a 'revenue at risk' mechanism included in the DPP.

Addressing the impact of extreme events

62. On the basis that reliability measures (SAIDI and SAIFI) are to be retained for the DPP, we submit that normalisation for extreme events remains important in setting quality standards because the occurrence and impact of these is largely outside the control of EDBs. Potential impacts of climate change over time also make extreme events less certain going forward and more difficult for EDBs to mitigate and manage.

63. We note that the IEEE 2.5 Beta approach to identifying extreme events was introduced for the first time at the beginning of the current regulatory period, and has also since been introduced into

information disclosures. Given the experience now with this approach in a New Zealand context, we submit it is timely to review the normalisation method, and if necessary refine and improve it. We note the QoSI group has also considered this issue and makes a number of recommendations in this respect.

64. In particular we support introducing improvements to the following features of the current normalisation approach:

- Extreme event days are currently replaced with a boundary value which is 2.5 beta above the mean. This means EDBs are exposed to a large proportion of the event even though it may be outside the control of the EDB. Alternative options include replacing the daily value with the mean, or zero (ie removing the day altogether – which is an approach adopted in other jurisdictions).

- Boundary values are significantly higher (as a proportion of the annual limit) for EDBs that have a greater number of zero event days. EDBs that are affected include those with a high proportion of underground cables and/or are small networks with few events. This means the normalisation is less effective, because if a major event is experienced, the boundary value applied on that day contributes a disproportionately high outage result to the annual result.

- Extreme events are assessed within 24 hour windows (ie calendar day), and capture all events (ie outages) which commence within that 24 hour period. Often there are a number of related outages which commence on subsequent days, but the impact of these within each subsequent 24 hour period is insufficient to exceed the boundary value. Thus it is often the case that only a relatively low proportion of the impact of a major storm is normalised, and the total impact of a major event (after normalisation) is severe enough for the quality standard to be breached.

- SAIFI extreme event days may only be normalised if there is a corresponding SAIDI extreme event day. Given the DPP quality standard is breached if either the SAIDI or SAIFI limits are breached two out of three years, this limitation is not justified, in our view.

65. Other alternatives to normalising for extreme events could be adopted to avoid these issues. For instance:

- Event days are excluded in different jurisdictions depending on various criteria:

  - In the UK an event threshold of 8 times the daily average fault rate is applied to faults on higher voltages to indicate an extreme event.

  - The IEEE 2.5 beta method is used in Australia to exclude events altogether (the boundary value is only used to highlight which faults to exclude).

- As part of its RCP2 proposal, Transpower is proposing to adopt a P90 longest duration metric. Under this approach, interruptions are ranked by duration and the highest 90% of interruptions are included in this metric. For EDBs, this could be reversed to select the shortest unplanned interruptions (ie by days or individual interruptions) to remove the effect of extreme events.

66. We also note and support further consideration as to how planned events are treated. Planned events are necessary to enable the network to be built, maintained and operated. We understand that these outages are less disruptive to consumers, given they are notified in advance, and where possible are scheduled to minimise disruption to consumers. Currently planned outages have the same status as unplanned outages in the DPP quality standard. We suggest they should have a lesser status, in particular to remove the disincentive to undertake planned work where an EDB may be at risk of breaching its quality limit.

Incentive scheme

67. We are supportive of a move to a revenue linked quality incentive scheme based on a cap and collar, similar to that currently applied in Transpower's Individual Price-Quality Path (IPP).

68. Tying the quality standard to a portion of the price path revenue explicitly recognises the price quality trade-offs that are inherent in the provision of electricity distribution services. This may provide incentives for EDBs to meet, if not out-perform, quality standards.

69. We note however, that overwhelmingly consumers have indicated to their network owners and operators that they are comfortable with current reliability performance, and do not wish to pay more for improved reliability, or would be willing to accept lower reliability.

70. Accordingly we suggest that before any incentive scheme of any significant magnitude is adopted, it needs to be tested with consumers, and the likely impacts on the prices they may pay, must be well understood and communicated to them.

71. The key features that will need to be determined include the:

    - the base level of reliability
    - cap and collar
    - incentive rates
    - revenue at risk
    - whether the incentive is applied symmetrically.

72. We welcome further analysis and consideration of these parameters. However, at this stage:

    - we support a symmetrical incentive (ie consumers' gain or loss is equivalent for the same rate of over/under performance). Asymmetric incentive rates are likely to add unnecessary complexity and we do not see that there is a justification for an incentive bias either way.
    - the revenue at risk should be a percentage of maximum allowable revenue (MAR) but exclude pass-through and recoverable costs. This is the most relevant incentive basis for a distributor and is consistent with the exclusion basis for defining recoverable and pass through cost. For the reasons set out above, we consider that the percentage of MAR should be a low percentage for the next regulatory period.
    - that SAIDI and SAIFI performance is weighted (possibly 50:50 for the next regulatory period for simplicity) in terms of the revenue incentive, but further consideration could be given to which measure consumers value more or less.
    - it is necessary to consider whether each non-exempt EDB should be subject to the same incentive rate or same cap/collar. Currently there is considerable divergence in SAIDI/SAIFI performance across the sector. Therefore we suggest that comprehensive analysis of the reliability datasets which have been provided to the Commission is required to test the likely range of the various parameters for all of the non-exempt EDBs subject to the DPP.
    - we support the inclusion of an option to suspend the incentives scheme where there are significant adverse events requiring greater use of planned outages to repair the network (eg such as for recent wind storms in the South Island).

Pass/fail regime

73. The Paper summarises the following issues with the current pass-fail regime, to which we respond:

- **The statistical allowance in the reliability limit may provide scope for a material deterioration in reliability over time without EDBs being non-compliant.** It is possible that the statistical allowance could lead to higher average reliability over time without there being a breach of the quality standard. However, the point of the allowance was to avoid the opposite; a breach of the quality standard where there had been no deterioration in long-term reliability. That is, a reliability limit based on the average would have resulted in more breaches where there was no long-term deterioration in reliability, simply due to normal year on year variation. This is, because annual reliability is expected to be greater than the average roughly half the time, all other things being equal. While the DPP quality limit is one reliability measure, it is not the only one, and as demonstrated in EDB asset management plans, and through annual statistical reporting, there is no evidence to suggest that the DPP limit has resulted in material deterioration in reliability performance, or that EDBs are forecasting such deterioration.

- **The two years out of three compliance assessment rule may incentivise distributors to exceed their reliability limit once but not two times in a row.** We are not convinced this is a material issue. Firstly, the two out three year rule is necessary to facilitate the efficient operation of a pass/fail regime, which focuses breach investigations on material deteriorations in reliability, as opposed to one off breaches due to natural variation in performance outside of the control of EDBs. Secondly, EDBs actively seek to avoid breaching the reliability limit in every year, and as noted above this is not the only measure against which EDBs set their performance targets. While a breach of the reliability limit in one year increases the pressure on the business to not breach the next year, there is no incentive to breach in the first year. The uncertainty surrounding the timing and severity of weather events creates too much risk to adopt such a strategy. It is also fundamentally contrary to the commitments made to consumers and published annually in AMPs and Statements of Corporate Intent.

- **The quality regime may have created an inefficient timing incentive for planned work, as EDBs delay planned works to provide more headroom for unplanned interruptions.** We agree that it may not be in consumers' best interests that planned work is delayed where EDBs are close to breaching the reliability limit. However, this could also be addressed under the cap and collar approach through disaggregation of the quality standard into planned and unplanned reliability and the adoption of a wider cap and collar and lower revenue at risk for planned outages. Alternatively, as suggested above, the two could remain aggregated but a lower weighting given to planned interruptions in the reliability target.

- **The Commission currently has discretion over the enforcement action that may be taken where the quality standard is breached, creating uncertainty for EDBs.** We agree that too much uncertainty exists regarding enforcement actions that the Commission might adopt, however this issue can be addressed through a number of ways, including enforcement guidelines and precedent.

74. Regardless of these reasons, we believe the introduction of a cap and collar approach could be a useful improvement to the current pass/fail approach. For example, no further action would be required where an EDB breaches its collar as it is already penalised through revenue reduction, passed on to consumers through prices.

75. If EDBs continually breach the collar then this may signal that the collar is too tight, the quality target is not appropriate for that business, or alternatively that the revenue at risk component is not sufficient to incentivise the company to invest in and operate their network in a way that improves reliability. In any case, the parameters can be refined over time over successive DPPs (including through the adoption of menu regulation which allows regulated companies to elect the strength of incentives).

Other performance-related incentives

76. The Paper identifies two further areas where there may be scope to enhance the DPP price path, namely by introducing:

- incentives to control expenditure during the regulatory period under an incremental rolling incentive scheme (IRIS) mechanism
- incentives for energy efficiency, demand side management and the reduction of losses.

IRIS mechanism

77. The Paper indicates that a draft decision on possible expenditure incentive mechanisms will be published in late April, with a final decision due before the next regulatory period. We have previously submitted on this proposal, and look forward to the draft decision in due course.

Energy efficiency, demand side management and reduction of losses

78. This topic was signalled in the 2012 reset decision, as one area for further development prior to the next regulatory period. The Paper indicates that due to the technical nature of these issues, it is proposed to rely largely on industry recommendations for mechanisms to provide incentives for energy efficiency, demand side management and the reduction of losses. The ENA's Energy Efficiency Incentives working group has developed a suite of recommendations, and we understand their report is to be submitted as part of this consultation. Accordingly, if necessary, we will provide further comment on this issue via cross-submission.

79. However, the following comments are also relevant to this topic:

- Section 54Q places responsibility on the Commission to demonstrate how its regulatory decisions incentivise, and also importantly, do not disincentivise, energy efficiency, demand side management and reduction of energy losses. Accordingly, while the industry may assist in developing mechanisms for the DPP, it is the Commission's responsibility to explicitly and transparently consider this obligation in all of its Part 4 decisions for EDBs.
- EDBs have undertaken effective demand side management activities for many years. While the technology may be changing, the opportunity and desire to control demand at peak times is not new. For example, we note that section 6 of the Electricity Authority's (EA's) Model Use of System Agreement (MUoSA) sets out that EDBs have the right to use load control to manage system emergency events or at the request of the system operator. The ENA is also working with retailers on principles for use of load control[6], based on the MUoSA. EDBs may use their own load control assets or may secure rights to use load control from other parties for other reasons to (eg peak demand management), although it is acknowledged that customers ultimately own the right to load control.
- It has been historical practice to use a combination of fixed and variable charges for distribution pricing. Variable charges often contribute a significant portion of total revenue, particularly for mass market consumers, partly as a result of the low fixed charge

[6] ENA, Load Management Principles (final draft), 30 August 2013

regulations and the complexities in complying with these at the 8000kWh and 9000kWh reference points. Thus the portion of revenue which may be affected by these initiatives may be significant. We therefore support consideration of ways to ensure that EDBs are able to achieve the recovery of their allowable revenues, while seeking to operate and invest consistent with the objectives of s54Q.

- Connection of small scale distributed generation is becoming more prevalent as this technology develops. This trend creates some uncertainty for volume and peak demand forecasts, future network capacity requirements, and recovery of network costs over time.
- Furthermore, EDBs may be exposed to greater volume risk than has historically been the case as the low fixed charge regulations combined with falling volumes places upwards pressure on variable charges, in order for EDBs to recover their fixed costs.

Treatment of uncertainty and risk

80. Section 6 of the Paper outlines several topics related to the treatment of uncertainty and risk, particularly in relation to:

- uncertainty over revenue and expenditure forecasts
- uncertainty and risk associated with pass-through and recoverable costs
- catastrophic risk.

81. We comment on these topics below.

Uncertainty associated with revenue and expenditure

82. The Paper highlights submissions made during the 2012 DPP consultation for an additional allowance to be included in the DPP price path in recognition of forecast uncertainty. One of the drivers for this proposal was the cost of potential forecast error, with no other recourse for an EDB, other than to apply for a CPP. It was argued at the time that a CPP was a costly and complex error correction mechanism.

83. The allowance (or wash up mechanism) was not accepted for the 2012 price path reset, and it is not proposed for the forthcoming regulatory period.

Demand forecasts

84. With regards to demand forecast risk, it is proposed that distributors manage this risk within a regulatory period as this is a key feature of a weighted average price cap[7]. However, we believe that the critical demand related issue in the context of the DPP reset is not about the weighted average price cap, but rather whether the demand forecast approach adopted contains errors, or unreasonable assumptions. EDBs are unable to control this risk because it is a regulatory setting risk not a business risk. We consider that at the very least the approach to forecasting real revenue growth adopted in 2012 should be assessed against actual results, before it is adopted for the next regulatory period.

Expenditure forecasts

85. There is also risk associated with errors in parameter projections relevant to expenditure. As discussed earlier, we believe forecast error can be minimised through the use of robust forecasting disciplines, including subjecting forecasts to rigorous ex-post testing and corroborating these with independent experts. We recognise though that even the best forecasts will diverge from real world outcomes and that some forecasting error is to be expected. However, we agree with sentiment expressed in submissions on the earlier 2012 DPP determination that a CPP is a 'high risk' and 'costly' error correction mechanism if starting prices are set too low[8]. We therefore support further consideration of whether or how a wash up mechanism could be applied to DPP resets to correct for forecasting errors in macro variables that are outside of the control of EDBs (such as CPI).

---

[7] Paper, paragraph 6.6

[8] *Ibid,* paragraph 6.3

Pass-through and recoverable costs

86. The Paper highlights issues raised in relation to uncertainty associated with forecast pass-through and recoverable costs. It is proposed that a similar approach to that applied in schedule 5 of the GDB DPP might be adopted[9], where only ascertainable pass-through and recoverable costs may be recouped within an assessment period, with deferred amounts recouped in future periods, once known, with a time value of money adjustments.

87. As a general principle, we consider that EDBs should not be exposed to pecuniary penalties under s87(3) of the Act for inadvertent and non-material breaches of the price path, including from uncertainty surrounding pass-through and recoverable costs. This, in our view, is not the intent of the price path regime.

88. The Paper acknowledges that EDBs often include DPP compliance buffers when setting prices in order to avoid unintentional breaches of the price path. Compliance buffers are used due to uncertainty over recoverable and pass-through costs but also to account for any unforeseen consequences when setting prices. While allowable notional revenues are restored in subsequent assessment periods through the differential term, compliance buffers represent foregone revenue in the current assessment period, which is never recovered. This represents a sub-normal return relative to the price path determination and is contrary to the expectation that non-exempt EDBs are able to earn at least a normal return over the regulatory period.

89. We submit that the DPP should not create situations where EDBs are forced to accept lower revenues than those determined in the DPP price path to avoid breaching the price path. Accordingly, we support further consideration of alternative mechanisms to address uncertainty in setting prices. This could include the introduction of:

- A similar approach to that under schedule 5 of the GDB DPP. We note the concerns raised by the ENA about the "ascertainable cost" solution and suggest that better alternatives should be considered for the EDB DPP particularly as the quantum of recoverable cost is much larger for EDBs than it is for GDBs.

- A wider wash up mechanism, which amongst other things, seeks to adjust for under or over-recoveries in a particular assessment period in future assessment periods. This is different to the current revenue differential term, as it is not seeking to restore the allowable notional revenue but rather allow for recovery of foregone revenue or pass back excess revenue.

- The development of enforcement guidelines which allow for under/over adjustments where price path breaches are inadvertent and not material.

Catastrophic risk

90. The High Court recently directed the Commission to amend the input methodologies to allow for a DPP re-opener in response to a catastrophic event[10]. In the Paper, it is suggested that a CPP is a more appropriate mechanism to address catastrophic risk because Part 4 only permits claw-back for a CPP. Furthermore, consistent with the Orion CPP decision, it is proposed that claw-back will not be provided to compensate for lower than forecast revenue resulting from a catastrophe, prior to a new price path taking effect.

91. We support the decision of the High Court directing the Commission to amend the IMs to re-open a DPP where there has been a catastrophic event. We do not consider that it is reasonable for a CPP to

[9] Gas Distribution Services Default Price-Quality Path Determination 2013, [2013] NZCC4, 28 February 2013

[10] Wellington International Airport Ltd & Ors v Commerce Commission [2013] NZHC, 11 December 2013.

be the only option for an EDB in this situation, and note the CPP IM does not explicitly accommodate the special circumstances facing a supplier following an event of this type. In our view, re-openers should initially focus on providing immediate temporary relief from the constraints of the DPP, where necessary. This could include:

- Temporary suspension of, or modifications to, the quality standard
- Recovery of immediate abnormal (net) costs associated with responding to the catastrophe which were not provided for in the price path
- Consideration of other impacts, including demand effects.

92. Temporary relief is particularly important to allow EDBs to focus on their immediate response to the catastrophe. We do not consider that a claw-back tool is necessary for making adjustments within a regulatory period, within the same regulatory mechanism (ie: the DPP).

93. A decision on whether to apply for a CPP is better made once the immediate response tasks are complete and planning for longer term restoration and rebuild, including understanding consumer needs, is able to be undertaken. This may reveal that a CPP is unnecessary, particularly following the next DPP reset.

94. Accordingly, it is important that the immediate impacts are able to be addressed via a DPP re-opener. In making these points, we do not suggest that an EDB's opportunity to apply for a CPP is diminished as a result of a DPP reopener.

Outstanding claw-back amounts

95. The Paper sets out a proposal to address the following outstanding claw-back amounts:

- Under recovery of 2012/13 allowable revenues due to the application of alternative X factors. This applies to five EDBs (Alpine Energy, Centralines, The Lines Company, Top Energy, and Unison)
- The NPV-negative impact resulting from the application of the alternative X factor. This applies to four EDBs (Alpine Energy, Centralines, The Lines Company, and Top Energy)

96. Key issues for further consideration include how claw-back amounts are to be calculated and recovered over the next regulatory period. It is proposed that:

- Claw-back amounts associated with any under recovery of 2012/13 MAR will be calculated in a similar way to that applied to other EDBs under the 2012 DPP as follows:
  - the difference between 2012/13 assessed MAR and disclosed line charge revenue net of pass-through, recoverable and indirect transmission costs is recovered
  - adjusted for the time value of money to 1 April 2015 terms
- Claw-back amounts related to the NPV negative rates of change will be determined:
  - as the amount of under-recovery in 2014/15 resulting from the application of alternative X-factor
  - adjusted for the time value of money to 1 April 2015 terms
- These claw-back amounts will be:
  - smoothed over each year of the regulatory period in present value terms
  - recovered through the recoverable cost term.

97. We support this proposal. Smoothing claw-back over the five year pricing period will limit price shock to consumers.

98. We note that alternative rates of change may also need to be applied for the forthcoming regulatory period, depending on the price reset calculated for each EDB. If that occurs, then recoverable costs associated with claw-back may need be adjusted for some EDBs.

Treatment of assets purchased from Transpower

99. Transpower has in recent years sought to focus on its core grid assets and as a result has sold spur lines and associated assets to distributors. Upon transfer of these assets, transmission charges have decreased but distribution costs (eg depreciation, operations and maintenance, capex and return on investment) have increased. Interruptions on the distribution network may also increase as a result of transferring these assets.

100. Clause 3.1.3(1)(e) of the IMs defines recoverable costs to include the pass-through of Transpower charges that the EDB has avoided liability to pay as a result of purchasing Transpower assets. This avoided cost of transmission (ACOT) charge is permitted for a period of 5 years. The rationale for including these ACOT payments in recoverable costs is:

> *"...to provide incentives for EDBs to undertake efficient investments that reduce the total cost of supplying electricity lines services, where all or part of those services are currently supplied by Transpower" - IM Reasons paper 2010, paragraph J2.24*
>
> *"As with any efficiency gain, this type of saving should be shared with consumers. EDBs should retain the full gain from the efficient investment for a period of five years, following which the gain will accrue in its entirety to consumers." - IM Reasons paper 2010, paragraph J2.26*

101. Several non-exempt EDBs are planning to purchase spur line assets in the next regulatory period. These purchases will impact transmission charges, expenditure and reliability.

102. The Paper responds to requests for clarification of the regulatory treatment of the purchase of Transpower assets for the DPP reset, in relation to:

- asset values
- forecasts of opex and capex in relation to these assets
- the recoverable cost allowance applying to asset transfers
- the extent to which asset transfers affect the DPP quality standard.

103. We discuss these topics below.

Asset transfer expenditure forecasts

104. The Paper discusses expenditure forecasts in relation to assets purchased prior to and after the commencement of the next regulatory period.

105. We note that information relevant to purchases that take place prior to 1 April 2014, will be included in information disclosures (eg RAB, tax, actual and forecast expenditure) and reliability data will include related interruptions from the purchase date. However, unless the assets were transferred prior to 1 April 2013, then it is likely that this information will not include a full year of opex and reliability data and that the DPP will be reset based only on part year information. This suggests that expenditure related to asset transfers should be based on either specific information requests or on AMP disclosures. This also highlights the benefit of using at least FY14 as a base year (supplemented by additional disclosures), as less recent data will exclude more of these transactions.

106. We are aware that the Commission has sought additional actual and forecast information regarding spur asset transfers, which may be included in disclosures, including AMPs. The Paper highlights that

information may not be available regarding assets which are transferred in 2014/15, after the date for providing responses for information gathering requests.

107. In this respect we support the proposal that EDBs could provide information on transfers (consistent with information disclosures) prior to the final determination. We also propose that EDBs are able to submit information for transfers that take place between this date and 1 April 2015 (the start of the next DPP period).

108. To facilitate this, it is proposed that estimates of these costs are included with subsequent corrections for any differences arising as part of the final transfer settlement (including no transfer taking place). We support this wash-up proposal.

Incentive mechanism and interaction with quality standard

109. The Paper proposes:

- That assets forecast to be transferred during the regulatory period would not be included in the RAB roll-forward as an incentive is already created by being able to treat related ACOT charges as recoverable costs.
- An adjustment to the quality standard is made to reflect the historical performance of the transferred assets.

110. We support these proposals. The recoverable cost allowance includes recovery of new investment charges. These should also be included where investment is undertaken in the assets, post transfer, as if Transpower had made the investment. Otherwise there is a strong disincentive against transferring assets which require capex investment in the short term, but where significant benefits are available through the lower investment costs able to be achieved by distributors. Currently the DPP Determination (not the IMs) prevents new (notional) New Investment Agreement (NIA) charges being included as a recoverable cost.

111. Adjustments to the quality standard are particularly important in setting a revenue linked cap and collar, otherwise this would mean EDBs would be exposed to lower average revenue due to lower reliability as a result of the new assets.

Treatment of asset transfer operating and capital expenditure

112. The Paper proposes that operating and capital expenditure associated with asset purchases in 2014/15 would not be included in the DPP reset as additional expenditure would be funded via the ACOT recoverable cost incentive.

113. We disagree with this proposal. The IM Reasons Paper stated:

> *"...[transfer] assets would be added to the RAB from the date of purchase, and the supplier would be able to recover the capital and operating costs of such assets from the date of the first reset following purchase" - - IM Reasons Paper 2010, paragraph J2.27*

114. Thus, there is a reasonable expectation that opex and capex associated with spur asset purchases would be included in the DPP reset if settlement took place prior to the reset. Accordingly, we submit that any relevant expenditure information that is included in Section 53ZD information notices relevant to purchases to be completed prior to the next regulatory period should be included in the DPP reset.

Distributor incentives to purchase Transpower assets

115. We acknowledge concerns regarding the different incentives that are created to purchase transmission assets in different years of the DPP regulatory period[11]. We welcome further discussion on how IMs

[11] Paper, Paragraph C30-C31

could be amended to equalise incentives throughout the regulatory period, and we consider this should be undertaken at the seven year review.

116. We also note a risk associated with the current incentive regime in relation to the EA's current review of the Transmission Pricing Methodology (TPM). The existing IMs only permit the recovery of ACOT payments set with reference to Transpower charges or new investment contracts. However, the current DPP provides further guidance that recoverable costs in years 2-5 of the 5 year incentive period should be set with reference to the TPM. There is a risk that the current TPM review could result in significant change.

117. For instance, the EA is currently considering a proposal to charge retailers instead of distributors for certain transmission costs. This could significantly reduce the recoverable costs associated with the transfer assets altering the incentives to purchase transmission assets part way through a DPP period.

118. We submit that the Commission should work with the EA to ensure the impact of any TPM changes do not create adverse incentives for distributors or consumers. We also consider that significant TPM change may be grounds for re-opening the DPP to address any re-alignment of incentives.

Concluding statement

119. We submit that for the purpose of resetting the price path, should the current and expected profitability option be used:

- opex forecasts are based on the existing DPP approach using recent information disclosures including FY14 data, subject to rigorous testing of network scale assumptions and incorporation of network capacity as a cost driver.
- capex forecasts are based on suppliers' 2014 AMP forecasts, subject to a cap on significant variation from historical norms. We have included analysis of historical capex in this regard to ascertain the magnitude of what a capex cap would be based on the GDB DPP approach.
- low cost models should not be relied upon to set capex as it is too late to develop these models with adequate consultation and they are unlikely to be superior to supplier forecasts based on robust AMP practices. Such models could potentially be used as a cross check, such as to inform the development of a cap.
- estimates of opex and capex partial productivity need to take account of any potential structural changes in the use of electricity and should be rigorously tested.

120. For the purpose of resetting the quality paths:

- we submit that SAIDI and SAIFI are appropriate measures. However, we believe it is timely to review the current approach to normalisation and to potentially adjust how planned interruptions are treated.
- we support consideration of the possible introduction of a revenue-linked quality incentive scheme. Any potential incentive scheme could:
    - be incrementally introduced to avoid price shock
    - be tested with consumers, to consider their willingness to pay for improved quality
    - incorporate a revenue at risk term based on a percentage of required revenue, symmetrically applied around a cap and collar
    - weight SAIDI and SAIFI, potentially with less weight placed on planned interruptions
    - consider an option to suspend the incentive scheme for significant adverse events
    - replace the current pass/fail regime.

121. We support consideration of the ENA's Energy Efficiency Incentives working group recommendations to better address incentives under the DPP relating to energy efficiency, demand side management and reduction of losses.

122. Uncertainty and risk surrounding key DPP inputs could be reduced through:

- the use of more robust forecasting and testing techniques
- the adoption of wash-up mechanisms, which seek to mitigate forecasting error in DPP parameters outside of the control of suppliers.

- the ability to re-open the DPP in response to a catastrophic event in order to provide immediate relief from the quality standard, to recover immediate costs associated with responding to the catastrophe, and to consider other impacts such as event effects.

123. We support further consideration of the Paper's proposed approach to spreading outstanding claw-back amounts over the next regulatory period.

124. With regards to the treatment of Transpower asset purchases, we submit that:

- Expenditure forecasts relating to the purchase and on-going operation and maintenance of Transpower spur line assets transferred prior to the next DPP should be included in the DPP price path.

- The treatment of avoided costs of transmission in the current determination be amended going forward to include notional new investment agreement charges as a recoverable cost as if the expenditure have been undertaken by Transpower, consistent with clause 3.1.3 of the IMs.

- Incentives under the DPP may be eroded in relation to Transpower asset purchases as a result of the EA's current review of the TPM. We urge the Commission to work closely with the EA to address these issues and submit that a material change in the TPM is grounds to re-open the DPP.

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

126. The primary contact for this submission is:

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

Appendix A: Calculation of capex cap based on GDB DPP approach

Non-exempt EDB total capex 2010-2013 (rebased to 2013 dollars)

$2013 million	Alpine Energy	Aurora Energy	Centralines	Eastland Network	EA Networks	Electricity Invercargill	Horizon Energy	Nelson Electricity	Network Tasman	Orion New Zealand
2010	11.3	14.8	5.6	5.1	20.7	2.7	2.8	1.5	4.9	38.1
2011	14.1	18.3	5.3	4.9	16.0	3.7	4.4	2.0	5.9	35.4
2012	3.2	10.4	2.6	4.9	14.1	3.6	4.8	1.2	4.3	49.8
2013	28.2	14.6	3.1	4.5	24.4	3.8	6.0	4.8	6.9	60.7

								Incl Orion		Excl Orion	
$2013 million	OtagoNet	Powerco	The Lines Company	Top Energy	Unison	Vector	Wellington Electricity	Total Capex	Annual Change (%)	Total Capex	Annual Change (%)
2010	7.0	77.3	8.4	8.6	36.8	107.4	31.3	**384.4**		**346.2**	
2011	9.6	76.7	7.6	14.0	29.8	135.5	25.3	**408.6**	**6.3%**	**373.1**	**7.8%**
2012	8.9	80.3	8.2	18.9	27.2	104.7	19.6	**366.9**	**-10.2%**	**317.2**	**-15.0%**
2013	8.6	83.5	8.1	31.0	22.5	124.3	23.1	**458.0**	**24.8%**	**397.3**	**25.3%**

Average annual change in total capex	**7.0%**		**6.0%**
Implied change over five year period	**34.9%**		**30.1%**

Notes:

a) 2010-2013 capex (nominal) sourced from schedule 5h(v) and 6a(i) of 2013 information disclosures for each non-exempt EDB
b) disclosed amounts are expressed in constant 2013 dollars using the capital goods price index
c) the average annual change in total annual capex (of all non-exempt EDBs) within this period is calculated as 7%, or 6% excluding Orion
d) the annual average change is multiplied by 5, consistent with the 5 year DPP regulatory period, to determine an implied cap.