Vector Limited
110 Carlton Gore Road
PO Box 99882
Newmarket
Auckland 1149
+64 9 978 7788 / vector.co.nz

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Ben Woodham
Electricity Distribution Manager
Commerce Commission
44 The Terrace
Wellington 6140
By email: infrastructure.regulation@comcom.govt.nz

Vector cross-submission on DPP4 Issues Paper

1. This is Vector's ('our,' 'we,' 'us') cross-submission on the Commerce Commission's (Commission) Issues Paper for the default price-quality path (DPP) reset. No part of this submission is confidential, and it can be published on the Commission's website. All quotations, unless referenced, are from responses to the DPP4 Issues Paper.

The sector is unanimous about the future investment required for electrification.

2. The sector does not always agree on many aspects of the regulatory regime, but there is growing consensus and broad support for the scale of the investment required in the distribution sector. The report The Future is Electric[1] by the Boston Consulting Group (BCG) is quoted in many submissions. This report recognises the $22 billion needed to be invested in distribution infrastructure to enable electrification in the 2020s. Including preparing networks for rapid electrification and multi-directional flows of electricity in the 2030s. The total investment needed in 2026–2030 is forecast to be 30% higher than 2021–2025.

3. The Energy Sector group describes the challenge ahead:

[1] BCG, The Future is Electric, October 2022 https://web-assets.bcg.com/b3/79/19665b7f40c8ba52d5b372cf7e6c/the-future-is-electric-full-report-october-2022.pdf

"There is widespread recognition that the scale of the investment challenge facing the electricity sector over the coming decades is unprecedented – in particular investment in transmission and distribution network infrastructure. The Commerce Commission's acknowledgement that the size of investment is significantly larger than in the past and an adapted capex forecasting approach is required - must be fully facilitated in the DPP4 allowances and approach."

4. The widespread recognition of the investment required must be backed by regulatory settings which enable electricity distribution businesses (EDBs) to fund the level of investment that electrification (and society) demands. The Part 4 Purpose Statement (s52A(a)) of the Commerce Act states that it is in the long-term interests of consumers that suppliers have incentives to innovate and to invest, including in replacement, upgraded, and new assets. Never has it been more critical that the Commission ensures there are strong incentives for EDBs to innovate and invest and more importantly there are no strong disincentives. Short term thinking must be avoided if New Zealanders are to get the future electricity system they need, and Aotearoa is to achieve its climate objectives. The remaining sections in this cross- submission outline how the Commission can unlock the settings required (with reference to viewpoints and ideas from stakeholders' responses to the DPP4 Issues Paper).

Financeability needs to be addressed with urgency.

5. Vector remains adamant that financeability and investability[2] (that is, appropriate levels of cashflow to support the debt and equity capital required to support infrastructure investment), be central to decision-making for the DPP reset. Decisions made for the 1 April 2025 reset must be tested by the Commission to ensure its regulatory settings will deliver the cash flows to support the attraction and reward of the capital required to fund the scale of investment and innovation discussed above. Without the right cashflows that support existing and attract new capital, EDBs will have no choice but to under invest and slow down New Zealand's electrification. This will see New Zealand slip behind other nations in the electrification of its energy system and put at jeopardy achieving net zero 2050. We consider it a significant lost opportunity that the Commission chose not to incorporate financeability testing and assurances into its recently undertaken review of the finding and foundational regulatory principles known as the Input Methodologies (IMs). However, it is not too late as those tests can be now inserted as part of the process the Commission undertakes in setting the default price paths for EDBs for 1 April 2025. The incentive to invest (encompassing the ability to invest) is paramount to the Part 4 Purpose statement governing the Commission's task.

[2] In Ofgem's open consultation on the RIIO-3 Sector Specific Methodology for the Gas Distribution, Gas Transmission and Electricity Transmission Sectors, they outline in paragraph 2.35: *We plan to develop the notion of 'investability', alongside our existing financeability assessment, to better understand whether the allowed return on equity is sufficient to retain and attract the equity capital that the sector requires.* https://www.ofgem.gov.uk/sites/default/files/2023-12/RIIO-3%20SSMC%20Overview%20Document.pdf

6. As explained by Electricity Networks Aotearoa (ENA):

> *"The deferral of revenue recovery beyond the DPP4 regulatory period would have material impacts on the ability of EDBs to fund the investment and ongoing expenditure needed to ensure that their networks can deliver the services expected and demanded by consumers. A curtailment or deferral of this necessary spending would be contradictory to the Commission's obligation to work for the long-term benefit of consumers."*

7. Horizon Networks considers the Commerce Commission should be considering the financial and financeability risks of this work to ensure EDBs can recover enough revenue to cover unforeseen cost escalation and the ever-increasing cost of borrowing. Unison is also supportive of a financeability test and equity issuance test to better provide for EDBs' interests as long-term infrastructure owners. They elaborate:

> *"Applying an alternate rate of change to minimise price shocks to consumers, without adequate protection against undue financial hardship, is where the DPP4 decision risks inconsistency with an ex-ante expectation of earning normal returns, consistent with the Commission's economic framework for Part 4. This would occur where non-exempt EDBs are unable to achieve borrowing costs consistent with the cost of debt allowance in the WACC due to insufficient cash flows. If EDBs are unable to meet debt covenants, their cost of borrowing may increase above the benchmark level. This would be contrary to the s 52A objective of providing incentives to invest."*

8. Retailers Flick and Contact Energy (Contact) acknowledge the funding difficulties facing EDBs and the tension this creates with the long-term benefit of consumers.

9. Flick describes "a difficult time for EDBs and for the Commission's efforts to regulate" but continues by noting that "the Commission's view that the threshold must be a high one before an EDB warrants accelerated revenue."

10. We emphasise that it is not "accelerated revenue" but "revenue due" to EDBs in accordance with a detailed regulatory model that the Commission has developed and refined over many years. But we do agree with Flick when they query:

> *"[…] if the Commission will be able to react quickly enough to avoid some harm to consumers as an EDB's financial position deteriorates."*

11. We share this concern resurfacing our disappointment with the IM review final decision not to introduce a financeability test into the regime. The Commission's refusal to appropriately address funding requirements within the IMs and provide the ability for EDBs to, with some degree of confidence, forecast cashflows means the regime now lacks a fundamental aspect of regulatory certainty. The Commission's retention of full discretion on how it may assess cashflow funding post the production of 2024 AMPs which will be used for the reset makes no sense. This undermines the regime at a critical time where there will need to be a step change

in electricity network investment. The Commission's approach can only be described as "the cart before the horse".

12. As it stands today, EDBs are expected to produce 10-year forecasts for the Commission so it can set the DPP on 1 April 2025 without EDBs having any certainty on the revenue caps the Commission will set for that DPP and/or what smoothing the Commission may do when determining starting prices. Vector questions how any Board can be reasonably expected to endorse such forecasts without knowing it will likely have the financial resources to undertake the forecast work. The Commission's answer to date has been "trust us" and statements suggesting the Commission already undertakes financeability testing. However, Vector submitted a report from Oxera (alongside our original submission) that characterised past financeability testing by the Commission as substantially lacking in many areas. It is now incumbent upon the Commission to provide suppliers, investors and other stakeholders with details of the financeability testing they will undertake to provide the confidence needed that the cashflows in the next DPP will support the debt and equity capital required for the levels of investment and innovation to support the long-term interests of consumers.

13. Contact disagreed with the Commission's position on a financeability test, and they called for such a test to be introduced into the DPP. However, while their submission focussed on better information, the key aspect of financeability is providing the confidence and certainty of the levels of cashflow required to support and fund the required levels of investment and expenditure:

    "To ensure that this investment is possible, we support calls for the Commission to undertake a financeability test as part of the draft decision. Applying such a test will provide better information to the Commission, the wider government and other stakeholders about the challenges of the next period."

14. We look forward to engaging with the upcoming consultation on 'revenue path and financeability.' We suggest that the Commission prioritises this workstream. Without certainty on regulatory settings EDBs are limited in their capacity to forecast their cashflows through to 2030. This means that the financeability decisions need to be brought forward so that the forecasts in EDBs' 2024 AMPs are derived with regulatory certainty which promote incentives to invest and innovate.

Capital contributions are essential to mitigate the financeability risks.

15. A key mitigation to financeability risks undermining investment are capital contributions which enable EDBs to recover the new investment costs of new connections by charging the connecting parties. Those connectees can include large data centres, EV charging stations and embedded solar and wind farms. Capital contributions policies that are designed around sound pricing principles ensuring there is no cross subsidy from existing consumers to new connecting parties. An added benefit is they help fund growth capex reducing the need to borrow as well as keeping the asset base lower than the counterfactual effectively lowering prices for all consumers.

16. Any regulatory changes that impact capital contribution policies by limiting the ability of EDBs to recover the incremental capital costs of connecting parties would have undesirable outcomes.

17. Firstly, if connection costs are not met by connecting parties, this has the undesirable consequence of 'smearing' connection costs caused by one party across others through lines charges, i.e., connection charges cease to be 'cost-reflective,' thereby departing from one of the defining principles of efficient pricing and also further lifting forecast price increases for consumers.

18. Secondly, they will require a greater level of investment in the network at a time when there is already forecasted to be a significant uplift in investment to meet the need of electrification. If suppliers already are faced with challenges in funding that investment, then capital contribution regulatory changes could make those challenges even greater. Possibly to the extent where a supplier may be unable or lack the incentive to make the required investments that are in the long-term interests of consumers.

19. We note the submissions by Drive Electric (with their Charge Point Operator (CPO) subgroup in mind), Infrastructure New Zealand (INZ) and Major Electricity User Group (MEUG) which have each called for a standardised or consistent approach to applying capital contributions by EDBs.

20. For example, Drive Electric states:

> *"Drive Electric CPO preferences here are that the risks and incentives around connection capex be carried by the party that is best placed to manage them. If capital contributions are retained as part of the network connection landscape, however, then the approach to their estimation should be consistent across EDBs, reflect efficient costs and account for the revenue contribution that the connecting customer will make into the future. This is the 'standard' approach employed under the regulatory systems in Australia and the UK."*

21. EDBs cannot price connections in a consistent manner due to:

    a. Cost reflectivity: It is in fact the diverging costs and local network characteristics that are the primary driver of an EDB's pricing. Drive Electric should instead be concerned if the tariffs were *not* cost-reflective, and there was a risk they were subsidising others' connections; and

    b. Access to capital: We have already noted that the Commission does not undertake a comprehensive financeability test when it sets the DPP, therefore it should not be assumed that EDBs will always be able fund investments in its network. To invest an EDB needs to obtaining funding. If cashflows under the DPP are insufficient to support credit metrics or returns and cashflows are insufficient to reward and attract equity, then required investments may not be able to be made. Access charges are a critical source of funding for EDBs. Any changes to access charging made through regulation may have unintended consequences, especially given lack of financeability testing in the Commission's current DPP setting process.

22. Any change in approach to connection pricing requires regulators to be extremely mindful of intergenerational equity issues. For existing customers who have paid upfront for their connections, a change in approach risks new consumers benefiting from the contributions of existing consumers without making a contribution of their own. Vector is concerned that the Commission could explore or entertain suggestions that EDBs should explicitly subsidise access seekers at the expense of existing customers.

Caps are a hindrance to decarbonisation.

23. Another aspect of the DPP which remains unresolved but would add to enhanced certainty of the financeability settings, are having details on revenue capping and any P0 revenue smoothing adjustments. For DPP3, the revenue cap was set at a 10% limit. These caps and any smoothing of starting price changes goes to the heart of financeability as deferring revenue increases the capital requirements of the supplier. This issue has become a focus for many submitters to the Issue Paper as the IM review has not provided any certainty or even guidance on how the Commission would look at these matters when setting a DPP.

24. Whilst we agree with Contact that the Commission has to do further work on defining what is a price shock, we disagree with their conclusion that "suggests that the 10%+CPI price shock threshold is at the higher end of a price shock estimate". Interestingly Contact provides little evidence, analysis or expert opinion on why this would be the case other than an old survey on levels of savings that could trigger a customer to switch retailers. At such a critical time for distribution network investment it is important that any quantification of what constitutes a price shock is determined by the Commission from robust analysis with stakeholders given the opportunity to consider and comment on that analysis.

25. The Commission should also take into account the contractual relationships EDBs have with retailers and end consumers when considering price shocks to consumers. On the whole EDBs do not bill end consumers they bill electricity retailers. Most electricity retailers do not pass EDB line charges on to end customers but instead bundle those charges with energy charges and other costs. Vector has advocated strongly in the past for mandatory retailer pass through of line charges along with separate disclosure on consumer bills. Retailers have largely campaigned against this, and it has not found favour with the Electricity Authority. As noted by Electric Kiwi retailers in the past have not in the past passed DPP starting price reductions on to consumers:

"The concerns are borne out by MBIE residential price monitoring which shows that while residential prices did go down following the last reset, the bulk of the network price reductions were absorbed in the energy (retail/wholesale) component of consumer bills. This highlights wider questions about how competitive the electricity market is and the

extent to which it can be relied on to ensure consumers get the full benefits of network price regulation."

26. No doubt retailers will have reasons for not passing on previous line charge reductions however what this behaviour does show when coupled with no mandatory requirement to pass through line charges is it cannot necessarily be assumed by the Commission that starting price changes will result in a straight flow through to end consumers. We are aware that retailers in the market offer fixed term arrangements for end users[3]. Therefore, akin to mortgages, retail energy is a competitive market, if end users are able to fix their costs and manage their price risk is there any requirement for the regulator to smooth price increases to manage price risk when a market is available for consumers to choose to do so or not.

27. Retailers have positioned themselves as the key interface with end consumers and this positioning has been reinforced by the Electricity Authority through regulation such as the Default Distributor Agreements (DDA). Retailers therefore play a key role in mitigating price shocks for end consumers. They currently do this for wholesale energy costs. Line charges should be no different. It is a failing of the retail market if products are not available in that market for consumers to manage their price risk. Banks are exposed to price volatility on international markets. They manage this volatility for their customers by offering products that enable those customers to manage their price risk if they choose to do so. The retail electricity market should be no different.

28. Section 53P(8)(a) is clear the Commission must consider price shocks to consumers and not price shocks to electricity retailers. We therefore consider it would be extremely difficult for the Commission to gauge price shocks to consumers without having a detailed and comprehensive understanding of the retail electricity market. Engagement with the Electricity Authority may assist here as we are aware that the Authority did previously have retailer pass through of line charges on its work programme. We encourage the Commission if they are considering implementing an alternative rate of change under 53P(8)(a) to smooth impacts of the change in prices for DPP4 that they are transparent on how they arrived at that rate of change given EDB prices largely related to ICP billing to electricity retailers and not end users.

29. The magnitude of the increases in risk-free interest rates from the reset in April 2020 alone will warrant starting price increases well above 10%. Limiting the increase in starting prices to smooth the impact will simply exacerbate the funding risks we described earlier in this submission. The expected starting price increases will predominantly not be the result of supplier behaviour but rather the regulatory model updated to new market-determined inputs. The lion share of starting price increases at the next reset will actually be driven by increases in interest rates and inflation – determinants out of the control of EDBs.

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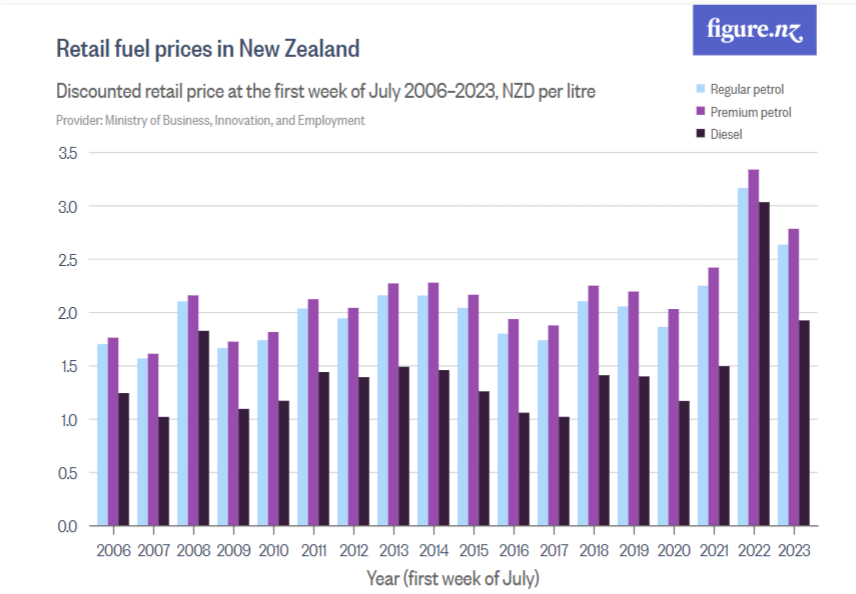
[3] Contact Energy makes reference to fixed term contracts in their submission.

30. The Commission may also be underestimating New Zealand's customers' ability to absorb price increases as is the case in workably competitive markets. The graph below from Figure.NZ[4] shows the increasing costs of fuel from 2006-2023, with the most notable increase of 40% from 2021-2022.



31. Other examples of recent price increases for consumers include:

    a. The price of food: NZ Stats marked a 22% increase on fruit and vegetables from June 2022 to June 2023[5]; and

    b. Mortgage rates: the graph below shows the stark increase in an average 2-year fixed mortgage rate in New Zealand[6].

[4] Copied directly from the Figure.NZ website without making any changes: https://figure.nz/chart/lSYJzICrinlIOY7p

[5] https://www.stats.govt.nz/news/food-prices-increase-12-5-percent-annually/

[6] From interest.co.nz: this series is based on our archived records for all banks, as at 5pm Friday 12th January 2023. It is a simple average of all retail offerings of each bank brand available here: https://www.interest.co.nz/charts/interest-rates/mortgage-rates

32. We recognise the burden of the cost-of-living crisis felt across the country in recent years. In contrast, lines charges have effectively been capped at a relatively low level with the current DPP being set for a five-year period from April 2020 when interest rates where at an all-time low. The distribution element of a consumer bill also only accounts for less than a third of the total bill. Additionally, the changing context of inflation and interest rate rises will not hit electricity consumers until the April 2025 reset and turn, passed on to consumers by retailers. (see our comments in paragraph 25 in relation to Electric Kiwi's submission).

33. Meanwhile, the Commission's reasoning behind applying a 10% cap on the P0 adjustment at the most recent Gas DPP reset was based on a judgement call and precedence from DPP1[7]:

> *"The 10% cap was a judgement call and reflected a balance between ensuring prices reflect the costs of providing the service, including the impact of shorter economic lives of assets, and minimising price shocks to consumers. The value of 10% has been used in a number of previous resets, for example in the 2010 to 2015 reset for Alpine Energy Limited, Centralines, The Lines Company, and Top Energy Limited where a 10% cap on price increases was applied."*[8]

34. Also, it is important to observe that within previous resets, when prices were falling, no caps were applied.

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[7] In the Electricity DPP1 final decision they described the CPI+10% "as a guide", paragraph 6.3, DPP1 final decision paper available here: [Final-determination-on-resetting-the-2010-15-default-price-quality-paths-for-16-electricity-distributors-30-November-2012.pdf (comcom.govt.nz)]

[8] Paragraph 4.41, Gas DPP3 Reset final reasons paper available here https://comcom.govt.nz/ data/assets/pdf_file/0025/284524/DPPs-for-gas-pipeline-businesses-from-1-October-2022-Final-Reasons-Paper-31-May-2022.pdf

35. If the Commission decides to smooth or cap price increases, the levels must be based on compelling evidence and analysis - not the light touch manner that has been used previously. The Commission also needs to ensure all revenues are returned within the regulatory period. In DPP1 the Commission stated:

"As a general rule, we have sought to minimise any price shocks by spreading the price adjustment over the regulatory period in an NPV-equivalent manner within the regulatory period. This is because we generally aim to set prices that are consistent with the amount of revenue that suppliers require to be able to earn a normal return over time."[9]

36. There is no regulatory precedence for cashflows not to be recovered beyond the regulatory period that revenues are due via the building blocks allowable revenue (BBAR) model. Our current indicative modelling shows that if the Commission smooths starting price impacts (like they did in the recent GPB DPP decision) and leaves current within period revenue caps in place at 10%, then EDBs will have to have to wait until the next regulatory period to recover revenue that has been deferred by the revenue cap mechanism and the P0 smoothing.

37. The need to cap and smooth EDBs' revenues is a consequence of the Commission's own regime, whereby past decisions have exacerbated revenue volatility. Vector has commissioned Competition Economists Group (CEG)[10] to perform a comparison of the volatility of the cost of debt using:

   a. The Commission's current estimation methodology (the prevailing risk-free rate at a 5-year tenor plus a five-year average debt risk premium (DRP) on 5-year tenor BBB+ bonds); and

   b. A simple ten-year trailing average of the yield on 10-year tenor BBB+ bonds.

38. We have attached their analysis with this submission and summarise the results below.

39. CEG estimates that the Commission's current method is 3.5 times (55/15) more volatile than the trailing average method, as measured by the average (absolute) percentage change in the cost of debt between each regulatory period.

40. Figure 1 below presents the two different methodologies since 2004 and table 1 presents the volatility of the cost of debt between regulatory periods in percentage terms.

*Figure **Error! No text of specified style in document.**: Cost of debt under reproduced NZCC method and trailing average method (where TA = trailing average cost of debt method)*

[9] Paragraph 6.4, DPP1 final decision paper available here: [Final-determination-on-resetting-the-2010-15-default-price-quality-paths-for-16-electricity-distributors-30-November-2012.pdf (comcom.govt.nz)]

[10] CEG, Relative volatility of cost of debt estimation methods, 26th January 2024.

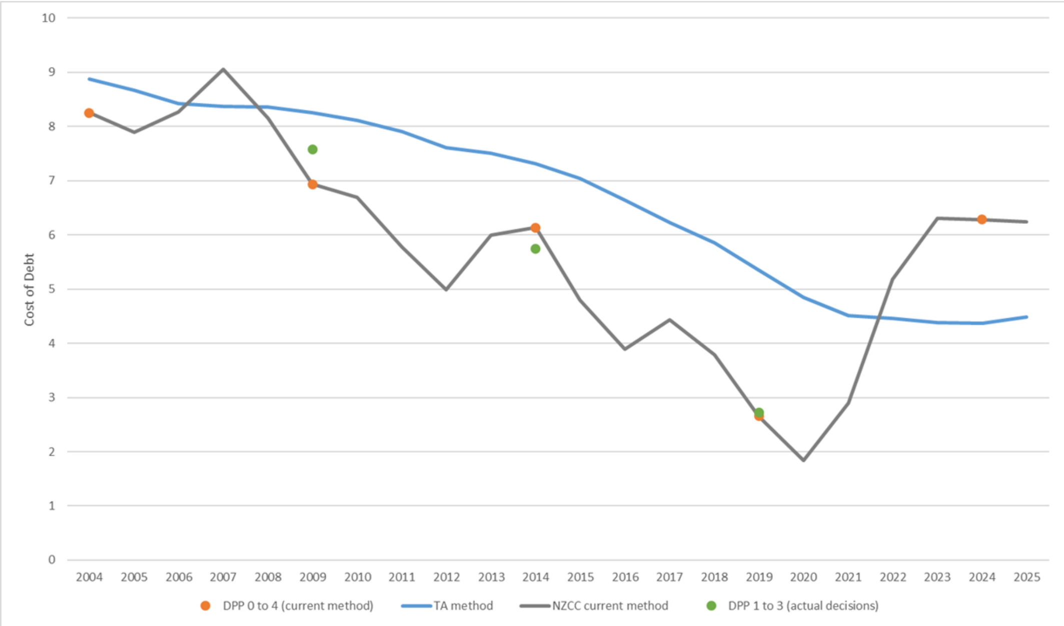

*Table **Error! No text of specified style in document.**: Volatility of cost of debt between regulatory periods*

Regulatory period	**NZCC current method**	**TA proposed method**
DPP0 to DPP1	-16.0%	-6.9%
DPP1 to DPP2	-11.5%	-11.3%
DPP2 to DPP3	-56.8%	-26.4%
DPP3 to DPP4	136.7%	-18.1%
Average change (absolute value)	55.2%	15.7%

41. Vector agrees with Unison:

> *"The fact that EDBs moved from DPP2, to an abnormally low DPP3 revenue path, has worsened the impact of a period of high inflation and growth and significantly increased regulatory uncertainty. To mitigate poor outcomes, it is essential that there are significant starting price increases to restore cashflows and certainty through the next period, consistent with providing incentives to invest in electricity distribution infrastructure. A continued 10% cap on revenue increase (the 'revenue movement cap') will not rebalance the potential inequity for consumers over time. It risks undermining investment on a 'least cost life-cycle basis', preventing innovation, and creating an industry wide issue of 'undue financial hardship'."*

42. Finally, the ENA recommends that the cap be lifted. Vector believes this could be a possible solution if the P0 adjustment is capped. But the decisions on the revenue smoothing and P0 must be made in tandem, methodologically with robust analysis and with supporting evidence. The Commission must factor the electrification and climate resilience challenges which lie ahead for EDBs; caps could hinder the funding requirements for suppliers pushing cashflows into the future when they are needed imminently.

The tension between avoiding price shocks and addressing supplier financial hardship should generally be resolved in favour of addressing financial hardship.

43. Section 53P(8)(a) of the Act which declares that the Commission must balance between avoiding price shocks and addressing supplier financial hardship, has provoked a lot of debate in the responses to the Issues Paper.

44. On one hand submitters favour increasing prices at the level required despite potential price shocks on consumers.

45. INZ recommends:

> *"[…] creating a more permissive investment environment for EDBs, by increasing the prices that they can charge to consumers, for the purposes of network upgrades. While we acknowledge that this will have a negative impact on household budgets, we consider that the missed opportunity in not investing in the required network infrastructure to be too great to miss, and that wider government policy can be used to address household income challenges."*

32. Electricity Retailers Association New Zealand (ERANZ) concedes that the Commission's task ahead must be pragmatic:

> *"ERANZ agrees with the Commission's assessment that the context for electricity consumers is changing. Over the past 15 years, households have benefited from declining electricity bills in real terms. Average household bills have gone from $2,261 in 2008 to $2,213 in 2023, a decline of 2.1% in real terms. But we are entering a pivot point where the costs of an economy-wide transition to predominantly renewable electricity coincides with the costs discussed in this document. Combined, such costs will put pressure on consumers and the Commission is right to have close consideration for how it can manage these bill shocks within the workings of the regime. Any revenue increases for distributors will ultimately end up being passed on to consumers."*

46. The tension is certainly real; the Commission observes that the standard price path may result in both a price shock and undue financial hardship, in which case the Commission proposes to exercise its judgment in resolving that trade-off.

47. The requirement to give effect to the s 52A purpose statement places a limit on the Commission's ability to defer revenue under s 53P(8)(a). That limit also does not reflect a trade-off between supplier and consumer interests; it is a limit rooted entirely in the long-term interests of consumers. If deferring revenue would undermine incentives to invest, ultimately consumers will be harmed as a result of that under-investment. Similar to the Commission's approach to WACC percentile, the long-term adverse impacts on consumers from under-investment in the network exceed the short-term impacts of paying higher prices.

48. In our view, in almost every circumstance a proper application of the Act will favour resolving undue financial hardship even if that exacerbates the price shock in the short term. This is because price shocks and supplier hardship do not represent a choice between consumer and supplier interests. Consumer interests are implicated in both situations. While consumers benefit in the short term from lower prices, their long-term interests are harmed if suppliers are not incentivised to adequately innovate and invest. Given the Act's prioritisation of the long-term benefit of consumers, per s 52A, in our view the tension in s 53P(8)(a) should generally be resolved in favour of relieving supplier financial hardship.

49. In the appendix to this submission, we outline how we come to this conclusion in relation to the DPP reset.

The Commission should refocus its lens for DPP decision-making.

50. Vector and others believe that the Commission's siloed focus on the distribution network sector for decision-making does not benefit the long-term interest of consumers.

51. Electric Kiwi has spelled out concerns around price changes which overlap the distribution and the retail sector:

> *"The concerns are borne out by MBIE residential price monitoring which shows that while residential prices did go down following the last reset, the bulk of the network price reductions were absorbed in the energy (retail/wholesale) component of consumer bills. This highlights wider questions about how competitive the electricity market is and the extent to which it can be relied on to ensure consumers get the full benefits of network price regulation."*

52. A solution to this issue which Vector has long advocated is for the Commission (or indeed policy makers) to look at consumer impact from an 'energy wallet' perspective.

53. We are not alone advocating for this. MEUG explains:

> *"What is missing from the framework is consideration of the overall impact of electricity prices and whether the total level of investment into the electricity system results in affordable prices for both consumers and businesses. We recommend that this issue be addressed as part of the Government's work on an Energy Strategy and its priorities around ensuring "there is sufficient electricity infrastructure to ensure security of supply and avoid excessive prices", separate to this current regulatory process."*

54. This is also one of Wellington Electricity's (WELL) astute suggestions to the Commission:

> *"Considering the household energy wallet: Electricity prices will increase as EDBs build and purchase (i.e., non-traditional services) more capacity. The impact of these changes needs to be considered in the context of the corresponding reduction in another energy cost. New*

household energy cost measures will need to be developed to demonstrate the savings provided by electrification."

55. There are clear issues with assessing industry requirements in silos. For example, beyond the retail and wholesale sector, the Commission is currently reviewing Transpower's RCP4 proposals which are predicted to increase prices by circa 25%[11].

56. There are also the intergenerational factors which need to be factored in such as adopting dynamic efficiency rather than static efficiency as a means of reviewing suppliers' productivity performance.

57. The argument about when EDBs should invest is also important. We support WELL's call upon the Commission to review their current position on the asymmetric consequences of investment:

    "We think the asymmetric impact of investing too early vs investing late should be re-qualified to include the wider economic consequences of investing late. We think this would provide important context to the price-setting process."

58. IEGA supports this view by sharing the results of a recent KPMG 30 Leaders report:

    "A recent survey of energy sector leaders revealed several saying that NZ won't get to our 2030 international commitments. The current cost of underachieving domestic emission reductions is estimated by The Treasury to be $23.7 billion (ie purchasing emission reductions from overseas projects)."

59. This is also backed up by the BCG report The Future is Electric which states:

    "The importance of forward planning and long lead times has been exacerbated by recent current supply chain headwinds, meaning that investing in transmission and distribution ahead of time is even more critical. In the future, the need for network investment to support decarbonisation is significant, but the timing of this investment is less certain. The above analyses suggest that the consequences of investing in networks too late significantly outweigh the additional costs of investing too early."[12]

60. The Commission has not done enough to disprove BCG and WELL's assertions that investing early benefits the long-term interests of consumers. In fact, we would encourage the Commission to review modelling which has already been produced by BCG in New Zealand (and other consultancies abroad), in order not to miss the opportunity here to allow for anticipatory investment when it comes to decarbonisation projects. At the least it must consider it within its draft capex framework workstream in early 2024.

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11 [Our proposed five-year workplan | Transpower]

12 BCG The Future is Electric, p.97

CPPs and reopeners will not provide the flexibility required in the regime.

61. The IMs review final decision was not to introduce any new flexibility mechanisms into the regime, such as use-it-or-lose-it allowances or trigger mechanisms. Vector hopes there is still an opportunity for new ones to be introduced part of the DPP4 reset.

62. Unison, PowerCo, Alpine Energy, and PowerNet all share their concerns around relying on customised price-quality paths (CPP) and/ or reopeners for the ability to adjust supplier allowances within the regulatory period.

63. Firstly, having gone through an identical process with the Commission on the catastrophic event reopener provisions, we concur with Unison.

> *"[…] Unison has suffered from the inadequate catastrophic event provisions that have been cumbersome and uncertain in the wake of Cyclone Gabrielle. […] The Commission should move to minimise adverse impacts on EDBs of provisions that are proving inadequate - both by adopting a purposive interpretation in DPP3 and restoring certainty in their utility for DPP4 by careful amendment to promote their intent."*

64. Vector reached out to the Commission in May 2023 to ensure our understanding of the catastrophic reopener provisions were correct. We are still in discussions with our respective legal teams at present.

65. Whilst it is positive that the Commission has rectified the issues to the reopener provisions in the recent IM review process, the outlook for Vector is that we will not have our allowances adjusted for the full expenditure incurred in reaction to the devastation caused by the Auckland flooding and cyclone Gabrielle in early 2023. On top of that we will also bear the legal costs for the ongoing interpretation discussions with the Commission (as will they).

66. Vector supports the views shared by other EDBs about CPPs and reopeners.

67. PowerCo acknowledges:

> *"[…] that a CPP may serve as a potential alternative to address financial hardship issues. However, it is crucial for the DPP to remain a low-cost option that is applicable to the majority of non-exempt EDBs. This means the DPP must adapt to the current context that requires increased levels of investment by EDBs. Additionally, it's important to recognise that implementing a CPP is a resource-intensive endeavour, consuming substantial EDB and Commission resources. Therefore, when resetting the DPP, careful consideration should be given to the potential volume of EDBs that may need to apply for a CPP. Many suppliers seeking CPPs may pose challenges for the Commission in processing them in a timely manner."*

68. Alpine Energy explains:

> *"Overall, whilst we acknowledge the low-cost nature of the DPP process, it would be inefficient for the end customers and EDBs to proceed along the route of DPP re-openers or CPPs to secure additional allowances. This would be massively disruptive, costly, and counterproductive. We are also concerned that the Commission will not have the capacity to process multiple reopeners and / or CPPs in a single year which causes concerns that the benefit from successful applications will not be timely."*

69. Horizon Networks describes:

> *"The reopener process risks delaying investment until it is too late, and consumers are forced to shift to alternative energy sources to meet their needs because the network is not ready for them."*

70. And PowerNet acknowledges that:

> *"[…] reopeners are available, whereby allowing changes to be made to the five-year plan, however, they are costly, slow and resource hungry to engage in. Decarbonisation customers want to consider a variety of options and expect prompt decisions and turnarounds. The regulatory regime is not conducive to their needs. Allowing more flexible assessments and adjustments to regulated expenditure would allow for the adaptation and evolution of the energy industry that is required as we transition to a more renewable electricity system."*

71. Beyond the EDBs there is acceptance of the serious issues, timing challenges and costs associated with CPPs. Drive Electric explains:

> *"For instance, we acknowledge that while the CPP option is available to EDBs, CPPs are simply uneconomic for all but the largest EDBs. DPP reopener rules and processes result in expensive and intense pieces of work for only small improvements. It would be prohibitive for EDBs to seek a reopener for discrete connections that were not forecast."*

72. With financeability being a key concern for Vector, we remind the Commission that in our Section 53ZD forecast we removed both resilience and EV growth expenditure due to the uncertainty of the regulatory settings, but on the clearly stated assumption that the reopener provisions would be certain enough to be exercised should that be necessary. We look forward to engaging with the Commission ahead of AMP24 to confirm our interpretation/assumptions.

73. The reality of the reopener provisions embedded in the current regulations is that there are significant challenges for both the applicant and Commission when there is little or no historical precedent or learnings on their use. We set out in our submission a number of times when we have been an early adopter to apply for a flexibility mechanism or incentive and the time it took to work out the complexities with the Commission. We need certainty from the Commission on their reopener provisions for those two categories of expenditure above before we can commit to our final forecasts in our 2024 AMP. We suggest the Commission consider how to avoid the

earlier adopter challenges to ensure reopeners do not become a barrier or disincentive to invest which would not be in the long-term interests of consumers.

74. The importance of resilience expenditure in DPP4 surfaces in the majority of submissions.

75. INZ explains:

> *"Recent weather events are a reminder how much our climate is changing, and how vulnerable our critical infrastructure is. These weather events are going to increase in frequency and severity, putting further pressure on already strained infrastructure across the country."*

76. Vector agrees with Horizon Energy that the Commission:

> *"[…] should consider that resilience needs and consumer resilience expectations change over time and are influenced by recent events and changing standards. Consumers are aware of the impact of recent events such as cyclone Gabrielle and post-event have an increased willingness to support resilience investment. However, resilience investment provides the most benefit to consumers when it is made ahead of need when consumers do not necessarily see the benefit. This issue makes resilience investment and expectations difficult to manage, and difficult to justify, except after assets have already failed."*

77. Finally, the recent IM change, to include resilience expenditure within scope of the major capex reopeners, seems almost crucial at this stage given the widespread agreement on the importance of ensuring EDBs' networks are resilient to the growing adverse effects of climate change. However, we remain cautious about the future use of reopeners in relation to resilience given our experience with the catastrophic event reopener. Vector would like to see assurances from the Commission that future interpretation will not be an issue, and EDBs are able to recover allowances incurred for resilience unforeseen or foreseen major resilience projects.

Opex needs to be a serious focus ahead of the draft decision.

Step changes

78. Vector is of the firm view that the means for assessing opex needs to be clarified and improved. Opex expenditures are crucial for electrification with data, low voltage monitoring, digitalisation, software as a service (SaaS), customer engagement and distribution system operator (DSO) enablement costs, all falling under this category.

79. We support Aurora's description that not allowing for increased opex allowances could accentuate bias towards capex expenditure:

"We are concerned that if the Commission does not allow additional levels of expenditure in these areas, distributors will be encouraged to pursue traditional capex solutions which may not be in the best long-term interests of consumers."

80. We were not the only submitter to call for more guidance around the opex step change process. Now that the Commission has attempted to clarify the step change criteria, it must explain the process for applying for an opex step change. It is unrealistic to assume that EDBs would have already submitted their step changes either in their 2023 AMP or their s 53ZD forecasts, without knowing the assessment criteria. The recent s 53ZD information request asked for information on variances between AMP23 and provisional AMP24 information. This process will not capture a step increase if that increase was both in AMP23 and the provisional AMP24 data. The Commission have described the opex setting process as a base step and trend approach. How will an expected opex uplift in for example RY27 be captured by this process? That increase could have been reported in both AMP23 and the provisional AMP24 data so would not be highlighted in the s 53ZD process and would not be included in the RY24 base year for the base step and trend approach.

81. PowerCo elaborates:

"There is a lack of clarity regarding the application process for EDBs seeking step changes. Additional information on the procedural aspects of this process would be beneficial."

82. ENA and Alpine Energy go further by suggesting potential solutions for the Commission to consider.

"*ENA encourages the Commission to establish and publicly communicate the threshold it intends to apply and engage with EDBs on how best to coordinate information and evidence gathering on step changes, and the presentation of this to the Commission."*

83. Alpine has suggested the use of:

"[…] an appropriate template, including the precise artefacts the Commission would seek to review as part of its decision-making process to meet the proposed criteria."

84. We agree that the Commission must describe the next stage of the process for opex step changes, whilst the idea of a template is a good one, Vector believes the ENA could coordinate rather than relying on the Commission, especially given that one of the step change criteria is that a step change needs to be attributable to most EDBs.

85. The criteria themselves have come under scrutiny. PowerCo says:

"The Commission's criteria for assessing step changes are too stringent and do not provide for new expenditure categories that may emerge during a regulatory period. In particular, the criterion to 'be robustly verifiable' is overly onerous and not practically workable. This is evidenced by the Commission's decision to reject a step change for cyber security costs

in the DPP3 reset due to a lack of information. In practice, for a spend category to meet the robustly verifiable criteria the need would have to arise at the exact time of the DPP reset.

86. Vector agrees with this conclusion by PowerCo and submits that the Commission must work with the sector to understand how best to ensure step changes which are hard to forecast (such as insurance, cyber, flexibility services) will be entertained in the assessment phase.

87. We however disagree with Independent Electricity Generators Association (IEGA) on avoided cost of distribution (ACOD) payments not being a step change in opex.

"The increased focus on 'flexibility services' which includes distributed generation should result in increased payments of ACOD to distributed generation and all flexibility service providers. However, we agree that higher ACOD payments are not a 'step change' as they will reflect the most efficient solution to address network issues."

88. Avoided cost of distribution (ACOD) payments are scarce for EDBs at present. This means that they would not be captured in any of the suppliers' base year opex. New costs for DPP4 must qualify as step changes. The difficulty for this particular category (flexibility payments) of expenditure is the ability to forecasts the levels of expenditure. We elaborate further on this point in the section on new incentives where we explain the opportunity for a new incentive for flexibility services to advance the sector into this market.

Scaling factors

89. Another aspect of the opex allowance setting process which warrants attention are the trend factors which feed into the base step trend approach.

90. Vector is concerned that the scaling factors do not consider future growth (bound to occur due to electrification, but also infrastructure investment more broadly such as water, roading and public transport) because they are derived based on historic data and trends.

91. WELL explains this in detail:

"We are concerned that New Zealand's electrification of transport and process heat is changing how the networks will grow in the future. This could mean that the historic relationship between opex and the opex drivers used for the network scaling, may not reflect future growth. EV's and natural gas to electricity conversions will increase energy use from existing connections. ICP and line length cost drivers will not capture the reinforcement of the existing network and the costs to support these work programmes. The relationship between increasing opex costs and new growth from existing connections may not exist in the historic data set. The regression analysis provided in the Issues Paper, tests the fit of different cost drivers using historic data. The analysis will not capture how well new drivers change operating costs if that relationship is not already in the reference data."

92. The ENA points out that:

> *"The primary limitation is that econometric modelling can, by its nature, only consider historical trends and cannot capture forward looking trends. This is vital as the distribution sector works to enable electrification which will see growth in demand from existing customers becoming an ever more important cost driver."*

93. The trend factors need to be looked at by the Commission ahead of the draft decision to ensure that the relationship between growing opex and historic trends does not adversely distort EDBs' opex allowance setting.

Insurance

94. The Commission must explore alternative ways to assess insurance costs.

95. We agree with Horizon that insurance is a risk management tool which is in place for the benefit of consumers.

> *"Horizon In terms of incentives for EDBs to make risk management decisions; insurance is a risk management tool that benefits consumers by limiting the shock of major events on prices. It is inefficient to require individual consumers to manage the risk of outages due to extreme events, and a stable price that includes an element of insurance against extreme events will be more palatable to most consumers, as compared to increased price volatility due to the costs of major events."*

96. Insurance costs are increasing more rapidly than other costs in the sector; the Commission must consider what different scaling factors could be used. It should also explore the pros and cons of introducing insurance as pass-through costs as this could also be a viable option Vector would be willing to support.

97. The Commission should investigate the Australian Energy Regulator's process for insurance pass-through events as a reference.[13]

The Commission has limited remit when it comes to EDBs' deliverability…

98. Though the Commission raised deliverability as one of their issues for the DPP reset, Vector does not believe that the regulator's remit extends that far.

99. This has enabled calls from certain submitters for the Commission to act in this area.

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[13] The AER's guidance note for insurance coverage pass-through event applications can be found here: https://www.aer.gov.au/news/articles/communications/aer-releases-final-guidance-note-assessing-insurance-coverage-pass-through-event

100. MEUG is one of them; they encourage:

“[…] the Commission to consider what mechanisms it has available if EDBs face significant delivery issues and by mid DPP4, are disclosing that they are not delivering the proposed level of investment. It is not in the best interest for consumers to continue to pay higher distribution charges, where projects are not being delivered and benefits not realised.”

101. There is no historical precedent under the DPP for the Commission intervening in an EDBs’ operating practices. If this door is opened it could allow an intrusion which the Commission, an economic regulator, is simply unfit to perform. We would also question how an assessment of deliverability fits with the Part 4 purpose statement s52A(1).

102. Vector supports the detailed rationale put forward by Unison on deliverability:

“The quality path provides mitigation for underinvestment in network performance, and EDBs must meet customer demand for electricity distribution services – including capacity, connection, and transportation – which is a primary driver of delivering expenditure plans. Each EDB is responsible for maintaining services and executing planned work programmes. It is not the Commission’s place to pre-judge their ability to do that using an assessment of sector wide deliverability challenges, as suggested in Attachment E.

Section 5Q of the Climate Change Response Act 2002 is relevant to deliverability. There will be a circular impact if the Commission constrains opex and / or capex allowances because it is concerned about deliverability. That lack of funding will create the major constraint and prevent EDBs from delivering the infrastructure required to reach the net-zero target.

Providing sufficient recovery for the under compensation of EDBs in DPP3, through significant starting price increases and a fair annual increase cap will considerably alleviate the adverse longer-term impacts of under investment. Re-balancing settings to ensure deliverability of capex work programmes also requires adequate opex allowances, and efficient recovery of costs to reduce cash-flow constraints.”

103. There is also the legal argument which precludes the Commission from intervening this way, in particular with an assessment of whether deliverability is consistent with:

a. the s 52A purpose statement; and

b. the scheme of default price-quality regulation under Part 4 of the Commerce Act.

104. We have made this assessment in Appendix B which in summary concludes that:

a. an assessment of deliverability is consistent with the s 52A purpose statement; but

b. given deliverability requires a highly individualised assessment of each EDB's capacity to deliver capex, it is unlikely that an assessment of deliverability as part of capex forecasting would be compatible with the low-cost objective of DPP regulation; and

c. the Commission's Issues Paper discussion of deliverability highlights the risk that consumers are required to fund additional returns to EDBs due to non-delivery, whereas the greater risk to consumers is that prudent and efficient investments are not delivered. That suggests the Commission should instead be focusing on ensuring that the regulatory settings support EDBs in delivering their AMPs.

105. One viable solution which could limit the Commission's deliverability concerns is to provide more uncertainty mechanisms in DPP4, in particular use-it-or-lose-it (UIOLI) mechanisms. Unfortunately, the Commission did not accept UIOLI schemes in the IM review final decision, even though they are still in consideration for Transpower[14]. UIOLI schemes provide carved out funds for specific projects or programmes of work, which if not delivered ensure the related funds are returned to consumers.

…But it does in communicating price changes to consumers.

106. A role much more relevant to the Commission will be to communicate the upcoming price increases properly and effectively to consumers as a consequence of the IMs and the DPP reset.

107. Meridian explains:

"Network costs will increase to reflect cost drivers and the investment needed to happen to support increased electrification. Meridian's understanding is that in DPP4, the majority of the cost increases are attributable to changes in input costs, such as the cost of capital and inflation. These costs will flow through to consumers. It is important that the Commission helps consumers to understand what is driving this. Cost increases need to be communicated widely, effectively, and well in advance. Tools to assist consumers, such as smoothing to avoid price shocks, should also be used."

108. ERANZ describes the complexity of the task ahead:

"Electricity billing is complicated, and it is challenging for the public to understand the different component parts of their bill. Therefore, ERANZ supports the Commission's desire to communicate the drivers and causes of increasing costs flowing through as bill increases to consumers. The Commission, as an independent government regulator, has a reputation for neutrality and therefore is a credible voice for explaining their role. The earlier the Commission starts to communicate the likely impacts of DPP4 to the public, the earlier consumers can start to prepare. In addition, this communication to the public can start a

[14] Paragraphs 5.34 and 5.35 of the Commission's RCP4 Issues Paper, 25th January 2024

conversation about the need for mitigating policies which, if required, will take time to develop and implement – again, the sooner this process can begin the better."

109. We agree with ERANZ above; part of the messaging must include the fact that the Commission's own IM framework will contribute to the largest part of the price increase through the impact of interest rates on the WACC.

110. And the 'Energy sector' submission outlines the need for transparency, well-communicated and appropriately supported. They continue by suggesting:

"Part of that is understanding retail price impacts in the context of the 'energy wallet' , and understanding the risk of underinvestment in transmission and distribution networks which could have even higher cost and price impact for consumers in the longer term."

111. As expected, the retailers desire better communications to consumers around the price increases to maintain good relationships with their customers. Vector calls for a collective approach involving EDBs (via the ENA) in the messaging (despite EDBs being excluded from engaging with end users when it comes to pricing).

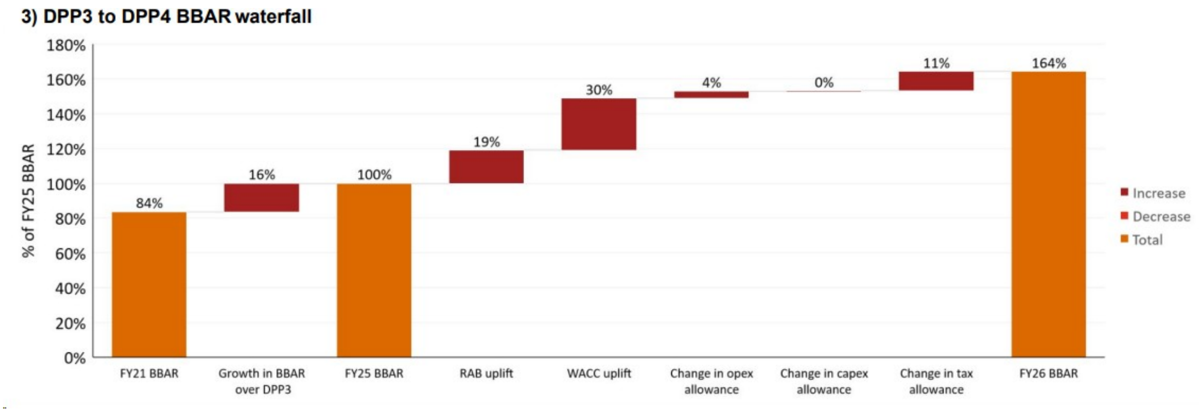
112. We support the Energy sector's view on the 'energy wallet' and the risks of underinvestment which we shared earlier on in our submission requesting that the Commission should refocus its lens on how it reviews the DPP.

"Consumer impact of the broader energy transition needs to be transparent, well-communicated, and appropriately supported. Part of that is understanding retail price impacts in the context of the 'energy wallet' , and understanding the risk of underinvestment in transmission and distribution networks which could have even higher cost and price impact for consumers in the longer term."

113. Another aspect of the price change that needs articulating is the elements of the increase that are uncontrollable by the EDB (such as interest rates and inflation) and the elements that are controllable (such as opex and capex required in delivering electrification and cyber security).

114. We refer to PWC's chart produced for PowerCo, whereby of the projected 64% BBAR increase between DPP3 and DPP4, only circa 4% (change in opex + change in capex allowances) is in fact under the EDB's control[15].

[15] Calculation for all non-exempt EDBs with all assumptions outlined in PowerCo's submission p.7.



And should in delivering Aotearoa New Zealand's climate objectives.

115. Another role which the Commission needs to start playing a larger role in, is delivering Aotearoa New Zealand's climate objectives.

116. We support the IEGA's call to understand the Commission's position on delivering New Zealand's climate change goals:

> *"The IEGA is interested to understand the Commission's view about what needs to happen in the distribution sector in the next 5-7 years to achieve NZ's climate change goals, especially our 2030 commitments? For example, should the Commission have oversight of the applications for new or expanded connections to distribution networks to understand the quantum, location and timeframes for this growth. If current EDB activity under the light-handed Price-Quality regime looks like it is not going to deliver the activity by regulated entities that is needed to deliver international climate change commitments would the Commission intervene / revise the regime to be more facilitative?"*

117. We would go further though and highlight that the IM decision making framework clarified that the Commission "may take into account the s 5ZN considerations (of the Climate Change Response Act 2002 (CCRA)) provided they are relevant and that doing so does not compromise our achievement of the s 52A purpose of Part 4".[16]

118. Decisions being made in this DPP reset will help deliver on New Zealand's climate change objectives (for example EV growth). We would argue that this consideration must be taken into account in both capex and opex allowance setting. Vector suggests this is raised part of the workshop on the draft capex framework.

[16] Clarification note dated 21 December 2021 available here: https://comcom.govt.nz/_data/assets/pdf_file/0022/302593/IM-Review-Decision-Making-Framework-Clarification-note-s-5ZN-of-the-CCRA-21-December-2022.pdf

The DPP does not have enough incentives to innovate.

119. There is (perhaps unsurprisingly) broad consensus that the innovation project allowance (IPA) is not an incentive enough to innovate in DPP3. Whilst there has been lots of focus on the Part 4 purpose around incentives to invest, the full text on s 52A is that suppliers have incentives to *innovate* and invest. Innovation, and the actual incentive to innovate, deserves much more attention from the Commission that has been explored to date. Given the scale of investment and value of electrification going forward, this is a critical part of the regime's statutory purpose for the Commission to deliver to.

120. We agree with Drive Electric:

"We observe that the enhanced incentives for EDB innovation that were included in DPP3 did not attract a successful application, suggesting to us that the wider EDB incentives require an urgent and complete review. In our view EDBs are coming under increasing pressure from electrification projects to make trade-offs between projects and across different priorities within their business. This means that the incentive arrangements for EDBs need to be considered as a "whole" so that they make the right decisions for their customers. This must be done for DPP4."

121. PowerCo's description is also accurate:

"We agree with the Commission's view that the current baseline incentives do not encourage distributors to innovate. Typically, the primary beneficiaries of innovation will be consumers, however the costs of innovation are usually borne by distributors in the form of IRIS penalties. This mechanism discourages distributors from pursuing non-network opex solutions and reinforces an inherent capex bias in the regulatory settings."

122. Meridian is incorrect to imply that EDB culture and capability are part of the problem. As regulated entities, EDBs are confined to the allowances awarded to them at the reset. PowerCo is right to point out that whilst IRIS should incentivise EDBs to be innovative and be efficient, the likelihood is that without better innovation mechanisms, EDBs will have to endure IRIS penalties to innovate, taking the financial risks of that innovation themselves.

123. Innovation trials and collaboration can be costly, but they can also be hugely rewarding for EDBs and consumers. However, the innovation project allowance is a cashflow hindrance with its ex-post assessment by the Commission and delayed revenue recovery mechanics (as we explained in our original submission to the Issues Paper).

124. We agree with ERANZ:

"Focusing on efficiency and technology can help distributors meet some of their needs at a lower cost than infrastructure upgrades. Technology and innovation should extend to demand management and other services that the market is likely to provide."

125. The 'Energy sector' also describes the situation on innovation well:

"Encouraging innovation, fostering creativity and facilitating non-traditional solutions will play a big part in decarbonising the energy sector while ensuring ongoing consumer choice and control. DPP4 can provide improved approaches to encourage innovation, while maintaining competition. We support the Commerce Commission workshopping with the sector on options for incorporating 'innovation and non-traditional solutions' into DPP4."

126. MEUG also supports measures to improve the interpretation and the usability of the IPA and suggests that further discussion on this issue may have merit.

127. Now that the Commission has published a date for the workshop on innovation, we recommend they propose solutions at that workshop rather than run through the issues raised so far on the current mechanism. In order for it to be an effective two-hour workshop, the Commission must send out the material in advance and avoid falling into a criticism of the IPA, but instead into ideas to remedy its effectiveness, or proposals for alternatives.

Why won't the Commission entertain new incentives for demand side management and/ or energy efficiency?

128. The Commission has misinterpreted the sector's desire for more incentives when it comes to energy efficiency and demand side response (DSR). Nor is the regulator adhering to s 54Q of the Act:

"The Commission must promote incentives, and must avoid imposing disincentives, for suppliers of electricity lines services to invest in energy efficiency and demand side management, and to reduce energy losses, when applying this Part in relation to electricity lines services."[17]

129. Across submissions there is strong disagreement of the Commission's initial view to not consider new incentives for energy efficiency or DSR.

130. SolarZero states:

"There is an urgent need for a specific incentive for demand-side management and energy efficiency. This is the critical period. The choice of path the industry takes over the next 5 years will determine whether New Zealand has a power system that deploys capital efficiently or one that is costly."

131. The Consumer Advocacy Council (CAC) considers:

[17] Commerce Act, section 54Q

"[…] there should be a greater focus on demand management and that this must be integral to EDBs' forecasting.[…] we disagree with the commission's initial view (para X34) that a specific incentive for demand-side management and energy efficiency is not required. We believe this needs to be considered to help control costs and ensure EDBs are not just taking a "business-as-usual" approach."

132. On behalf of the EDBs, ENA puts forwards that:

"A well-designed demand-side management and energy efficiency incentive that allows for EDB involvement in energy initiatives that maximise energy use, minimising energy loss and reducing customer costs for the distribution service and would be beneficial to the system as a whole and to the long-term interest of consumers. Thereby supporting the achievement of Section 54Q. In the absence of a demand-side management and energy efficiency scheme, the DPP should include alternative measures such as step change, use-it-or-lose it allowance or pass-through for the procurement of flexibility services."

133. Vector, Counties Energy, Orion, Unison and WELL have called upon the Commission to consider a new incentive or innovation allowance specifically to address energy efficiency and/ or DSR. We believe this should be a focus of the innovation workshop on 26th February.

134. We refer to Unison's justification capturing the suggestion at an important level:

"We support incentives in investment in energy efficiency and demand side management and removing existing disincentives. It is fundamental to promoting Part 4 to have clear, effective mechanisms for non-exempt EDBs to optimise efficiency and demand side management outcomes for consumers. An innovation allowance for flexibility payments may ameliorate existing disincentivises to invest in energy efficiency and demand side management solutions in the context of:

- *forecasting for capex solutions, where there is certainty of cost on a least cost life-cycle basis; and*
- *forecasting for uncertain opex solutions such as procuring flexibility in an environment of underfunding for opex."*

135. Finally, for DPP4 the value to distributors of DSM, flexibility services and DER will be small. Therefore, the focus needs to be on the investment to enable these in the future not that they will be able to deliver any real value to distributors and consumers in the short term. A new incentive or innovation scheme could really benefit unlocking the value in this space.

Expenditure forecasts change and network utilisation is an essential part of that.

125. NZIER has made some comments in relation to EDBs' forecast changes within their AMPs:

“ NZIER for MEUG Comparison of the asset spending plans by each of the six largest EDBs highlights that the plans for the Vector, Powerco, Orion and Wellington Electricity are markedly different from both their past plans and each other. In particular: Vector follows the usual pattern of step-up in the first two years followed by a gradual decline. However, the step change in the 2023 AMP is much greater than in previous years”.

136. The reason why Vector’s 2023 AMP forecast shows a step up in the first two years, followed by a gradual decline, is down to certainty. The further away we project our investment plans, the more uncertainty we have around them materialising, therefore it is incumbent on EDBs to ensure we forecast only those projects and programmes of work that are certain. For that reason, the first years of forecasts will be larger than the remaining.

137. Vector’s 2023 expenditure plan also increased in comparison to its previous versions from earlier AMP disclosures primarily due to the growth in data centres and resilience measures contained in our latest published disclosure.

138. Solar Zero is correct to point out that lines companies need to:

“Manage peak demand growth via pricing, demand response and influencing the uptake of technology like solar and batteries (which will be via pricing), working with communities and aggregators.”

139. These comments align with Vector’s Symphony Strategy.

140. Our forecasts show that peak demand growth in the future will be mostly driven by electric vehicles and using electric hot water instead of gas. Both of these loads – EV charging and water heating - can be shifted away from peak times through 'orchestration'. We believe there is a big opportunity to reduce the amount of actual peak demand growth through moving when these loads come on outside of peak time. Though we council that it is not necessarily easy to get the right arrangements in place to ensure the benefits from peak management can be realised. It is for this reason we were disappointed that the Commission did not put in place in its recent IM Review the ability for “sandboxing” so various parties could experiment and trial to see what is achievable in this area.

141. The next ten years is also a critical decade for unlocking longer term affordability. Higher peak demand requires more network investment, which is passed on to customers, but everything we do to reduce that peak demand should make energy more affordable for end users providing those benefits are passed through by retailers.

The Electricity Authority (Authority) should not intervene in setting quality targets.

142. WELL has rightly pointed out issues with the Authority’s recent proposals to add new quality targets through the DDA:

"We are concerned that new quality targets and service levels will be added by the EA and enforced through Electricity Code changes outside of the Part 4 price/quality regulation. Proposed changes to DDA would improve customer quality at an additional cost not included in regulatory allowances. Even if additional costs are provided, we are concerned that quality levels are being changed without consideration of the price trade-off and whether customers are willing to pay more. Any quality changes need to be made through Part 4 price/quality regulation so that the Commission can balance the trade-off of higher prices for quality improvements on behalf of the customer. We ask that the Commission works with the EA to ensure that any changes to quality are considered along with the cost impact and allowances are adjusted so that financial capital maintenance is maintained. Details of the proposed changes to the DDA are provided below."

143. Vector agrees with WELL. We outlined our arguments in our submission[18] to the Authority in relation to these changes:

"Finally, we take exception to the view expressed at paragraph 2.27 that "distributors do not have sufficient further incentives to manage the quality and reliability of electricity supply or to minimise power disruption to consumers". We disagree entirely. Our consumers are at the very heart of what we do and the delivery of affordable, reliable and intelligent energy, so that consumers have more choice and control is at the core of our Symphony strategy.

The comment is also surprising, given that distributors are subject to the Commerce Commission's quality-incentive regime under the price-quality path. Under that regime, we are incentivised to restore power as quickly as possible and to plan outages as accurately as possible through the DPP's quality incentive scheme."

144. Along with WELL we ask that the Commission works with the Authority to ensure that any changes to quality are considered inside either the DPP or a future targeted information disclosure review and not within the Authority's code changes.

The costs outweigh the benefits of reducing the regulatory period to four years.

145. Vector supports maintaining the regulatory period at five years. Amongst many submitters who shared this view, we believe Unison explains the reasoning best.

"The IM Review and DPP reset are administratively burdensome and expensive processes for EDBs and the Commission. This will impact on capacity to complete large work programmes through a period requiring innovation and agility to respond to rapid growth.

Time and money would be better spent getting the work done with proportionate and agile regulation. The additional cost required to deliver a shortened four-year regulatory period

[18] Vector Submission EA DDA Amendment Consultation, 14 November 2023, available here: project name (vector.co.nz)

is relevant to the s 53K purpose and adopting a "relatively low-cost way of setting price-quality paths…"."

146. As always, if there are any elements of our submission that you would like to discuss please feel free to get in touch.

Yours sincerely

[redacted]

Richard Sharp

GM Economic Regulation and Pricing

Appendix A: Taking into account "financial hardship" in the DPP reset

Introduction

1. Following section 53O of the Commerce Act, the DPP price path comprises two components: (i) starting prices, and (ii) an annual rate of change in prices.

2. Section 53P requires the Commission, at the end of each DPP regulatory period, to 'reset' the starting prices and determine the rate of change for the next regulatory period. Starting prices must be either the prices that applied at the end of the preceding period (i.e. "rolled over"), or prices determined by the Commission based on the current and projected profitability of each supplier.

3. The rate of change in prices is made up of: (i) the rate of increase in CPI, and (ii) a rate of change relative to CPI (the 'X-factor'). However, section 53P(8)(a) also provides that the Commission may set alternative rates of change for a particular supplier if, in the Commission's opinion, this is necessary or desirable to minimise any undue financial hardship to the supplier or to minimise price shock to consumers.

4. In its DPP4 Issues Paper the Commission has highlighted related concerns of energy hardship experienced by consumers and financeability of the regulated service in the context of resetting starting prices and rates of change under s 53P.

5. In this Appendix we:

   a. summarise what the Commission has said regarding the financial hardship test in s 53P;

   b. explain the circumstances in which a price shock will warrant intervention and what considerations are relevant to the Commission's assessment;

   c. offer some observations on the Commission's interpretation of "undue financial hardship;" and

   d. explain why the tension between avoiding price shocks and addressing supplier financial hardship should generally be resolved in favour of addressing financial hardship.

What has the Commission said?

6. Chapter 5 of the DPP4 Issues Paper discusses the Commission's task in setting starting prices and rates of change. The Commission has identified two issues relevant to the DPP4 reset:

   a. a number of New Zealand households struggle to afford energy services, which has been exacerbated in recent years by the increase in general inflation across the economy; and

b. on the other hand, a number of EDBs have told the Commission they may face financeability challenges over the next regulatory period due, in part, to the significant increase in investment required to support electrification of the economy and increase resilience of networks to climate impacts.

7. The Commission explains that the primary regulatory tools it uses to ensure consumers receive value for money are: (i) revenue caps that limit excessive profits, (ii) efficiency incentives, and (iii) transparency and accountability through AMPs and pricing disclosures. The unstated premise is that consumers' interest in the affordability of the regulated service is primarily met by ensuring consumers pay no more than the efficient costs of providing the service, including a normal return on capital. That is an important acknowledgement because s 52A does not permit the Commission to set allowable revenues that are less than the efficient costs of the service in order to make the service more affordable in the short term.[19] That would not be in the long-term interests of consumers because it would undermine incentives to invest.

8. With that in mind, section 53P(8)(a) is about cashflows and the time profile of cost recovery, rather than whether or not suppliers are entitled to recover their efficient costs.

9. The Commission observes that the two outcomes in s 53P(8)(a) are in tension: bringing cash forward to minimise financial hardship for suppliers may create or exacerbate a price shock, and delaying cash may create or exacerbate financial hardship for EDBs. In some cases, the Commission notes that there may be a risk of both a price shock and financial hardship at the same time, in which case the Commission will need to exercise judgment in trading off between them.

10. The Commission has explained that it will undertake the analysis contemplated by s 53P(8)(a) in three steps:

    a. first an assessment of whether a price shock or undue financial hardship would occur, based on the Commission's decision on starting prices and the generally applicable rate of change (i.e. CPI);[20]

    b. second an assessment of whether it is necessary or desirable to minimise these outcomes; and

    c. third a decision about the alternative X-factor that would best minimise these outcomes.

11. The remainder of this note assesses the Commission's discussion of its role under s 53P(8)(a).

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[19] Albeit the Commission can, consistently with s 52A, set price paths that result in deferral of revenue between regulatory periods, provided the supplier is made whole in real terms over the long run.

[20] The Commission has indicated it is proposing a 0% X-factor, absent alternative rates of change, because long-term changes in productivity are already incorporated in starting prices.

What level of price shock warrants intervention?

12. The Commission rightly observes that the Act does not define what constitutes a price shock. The Commission says it will exercise its judgment regarding the percentage change in real distribution revenue that would warrant intervention having regard to the policy and objects of Part 4. In applying this judgment, the Commission will consider:

    a. the impact of any deferral of incentives to invest and to improve efficiency under s 52A; and

    b. the risk that deferral of cash flows may itself give rise to financial hardship for suppliers.

13. We agree that the level of price shock that warrants intervention requires judgement, and that judgement should be exercised consistently with the objects of Part 4 including, particularly, the s 52A purpose statement. The section 52A purpose statement is relevant to every decision the Commission makes under Part 4. We also agree that the impact of revenue deferral on incentives to invest and improve efficiency is relevant.

14. We would go further and say it would be inconsistent with the s 52A purpose statement for the Commission to defer revenues to address a price shock if that undermined incentives to invest under s 52A. The requirement to give effect to the s 52A purpose statement places a limit on the Commission's ability to defer revenue under s 53P(8)(a). That limit also does not reflect a trade-off between supplier and consumer interests; it is a limit rooted entirely in the long-term interests of consumers. If deferring revenue would undermine incentives to invest, ultimately consumers will be harmed as a result of that under-investment. Similar to the Commission's approach to WACC percentile, the long-term adverse impacts on consumers from under-investment in the network exceed the short-term impacts of paying higher prices.

What is undue financial hardship?

15. Undue financial hardship is also not defined in the Act. The Commission refers to the inclusion of the term "undue" in support of the proposition that the threshold is a high one and that not all financial difficulties a supplier faces would warrant accelerated revenue. The Commission argues that financial hardship will be undue "only where it is to such an extent that it is inconsistent with the long-term benefit of consumers." The Commission goes on to say that this would be the case, for example, where the price path is set "such that it would not be feasible for any prudent supplier to deliver services under it."

16. We make four observations.

17. First, we agree that the inclusion of the term "undue" in the phrase "undue financial hardship" implies that not all financial hardship requires intervention under s 53P(8)(a). But we disagree that the term "undue" in this context implies a high threshold in the sense that only a large or very substantial amount of financial hardship qualifies for intervention. In our view, "undue" in this context merely means that the financial hardship is unwarranted, inappropriate or

excessive under the circumstances. That could be, for example, because the financial hardship that results from the Commission's starting prices adjusted at CPI will undermine the delivery of the supplier's asset management plan. We also think "undue" in this context allows for a balancing of the need to mitigate price shocks and the financial circumstances of the supplier. So, for example, if the 'standard' price path would result in some amount of financial hardship and, conversely, bringing forward cash would not result in a significant price shock, then the financial hardship is "undue" because it is avoidable without compromising consumers' interests in price stability.

18. Second, the Commission argues that financial hardship will only be "undue" where it is inconsistent with the long-term benefit of consumers. We agree that if financial hardship is inconsistent with the long-term benefit of consumers, then intervention is warranted under s 53P(8)(a). That follows from the s 52A, which is relevant to every decision the Commission makes under Part 4. But we do not agree that this is the only circumstance in which intervention is warranted. Section 53P(8)(a) provides that the Commission can intervene where the supplier is experiencing undue financial hardship. On a plain reading, the Commission should have regard to the supplier's interests when applying the section. It is not necessary that consumer interests are also implicated. That said, financial hardship on the part of the supplier will generally also undermine the long-term benefit of consumers.

19. Third, the Commission says, by way of example, that financial hardship would be inconsistent with the long-term benefit of consumers when it would not be feasible for any prudent supplier to deliver services. That sets far too high a threshold for intervention. The long-term benefit of consumers is defined in s 52A and includes, for example, that suppliers:

    a. have incentives to innovate and to invest, including in replacement, upgraded, and new assets; and

    b. have incentives to improve efficiency and provide services at a quality that reflects consumer demands.

20. If the financial hardship caused by the 'standard' price path is such that it undermines the supplier's incentives to innovate, invest, improve efficiency and provide services of appropriate quality, then the price path is not promoting the long-term benefit of consumers. That is the standard of consumer benefit that is established by the Act. Conversely, consumer interests would be compromised well before we arrived at the point that no prudent supplier could feasibly deliver the regulated service.

21. Fourth, the Commission in paragraphs H42-H43 states that it will consider what mitigants are available to the supplier to relieve the financial hardship. We agree the availability of mitigants is relevant but:

    a. if the Commission takes into account the supplier's ability to raise additional debt or equity capital, it needs to do so on the basis of a practical assessment of the challenges of raising capital under the circumstances; including, for example, shareholders' reasonable expectation that dividends will not be indefinitely deferred; and

b. the Commission should be careful before suggesting that suppliers should defer capex in order to address financeability challenges. Only capex that is demonstrably in consumers' interests is recoverable through regulated prices under Part 4, which means there is little capex in most suppliers' asset management plans that could genuinely be described as "discretionary". As the Commission has observed on a number of occasions in recent years, deferring capex will often compromise the long-term benefit of consumers by increasing asset risk, depriving consumers of quality improvements or innovations they would benefit from, or creating a 'bow-wave' of deferred investment.

What if the standard price path results in both a price shock and undue financial hardship?

22. The Commission observes that the standard price path may result in both a price shock and undue financial hardship, in which case the Commission proposes to exercise its judgment in resolving that trade-off.

23. In our view, in almost every circumstance a proper application of the Act will favour resolving undue financial hardship even if that exacerbates the price shock in the short term. This is because price shocks and supplier hardship do not represent a choice between consumer and supplier interests. Consumer interests are implicated in both situations. While consumers benefit in the short term from lower prices, their long-term interests are harmed if suppliers are not incentivised to adequately invest. Given the Act's prioritisation of the long-term benefit of consumers, per s 52A, in our view the tension in s 53P(8)(a) should generally be resolved in favour of relieving supplier financial hardship.

Appendix B: DPP4 - assessing deliverability

1. On 2 November 2023, the Commission published its DPP4 Issues Paper outlining the issues it anticipates addressing for the 2025 reset of the electricity distribution default price-quality path.[21]

2. The Issues Paper notes the Commission has "*concerns about the challenges in delivering increased programmes of work given current labour market, supply chain and economic challenges in New Zealand*" and asks "*how should our capex forecast take into account potential sector-wide deliverability constraints?*"

3. We ask to what extent an assessment of deliverability is consistent with:

   a. the s 52A purpose statement; and

   b. the scheme of default price-quality regulation under Part 4 of the Commerce Act.

4. In summary:

   a. an assessment of deliverability is consistent with the s 52A purpose statement; but

   b. given deliverability requires a highly individualised assessment of each EDB's capacity to deliver capex, it is unlikely that an assessment of deliverability as part of capex forecasting would be compatible with the low-cost objective of DPP regulation; and

   c. the Commission's Issues Paper discussion of deliverability highlights the risk that consumers are required to fund additional returns to EDBs due to non-delivery, whereas the greater risk to consumers is that prudent and efficient investments are not delivered. That suggests the Commission should instead be focusing on ensuring that the regulatory settings support EDBs in delivering their AMPs.

What has the Commission said about deliverability?

5. The Commission has said that, in reviewing expenditure forecasts, it will consider "*any likely deferral of efficient investment because of deliverability or financeability concerns*."[22]

6. The Commission has observed that EDBs are foreshadowing a significant step change in forecast expenditure in their 2024 AMPs, on top of the material increase in 2023 AMPs, driven by a combination of price increases and the size of the work programmes.[23] The Commission is "*concerned about the deliverability of the scale of the work programmes…*

[21] Commerce Commission, *Default price-quality paths for electricity distribution businesses from 1 April 2025: Issues paper* (2 November 2023).

[22] Issues Paper at para X20.

[23] Issues Paper at para 3.26.

given the current labour market conditions and wider supply chain challenges, which [are] expected to continue in the medium term”.[24] The Commission says this presents a risk that “*projects are planned but are not delivered, with the result being elevated profits for EDBs not through improved efficiency but non-delivery”*.[25] The Commission also notes that:

a. projects may be feasible at an individual EDB level but not at an aggregate level if other suppliers are planning to deliver similar projects, meaning there is competing demand for the same skills across the industry;[26] and

b. deliverability may be constrained by other infrastructure investment programmes in other sectors.[27]

7. The Commission has consequently asked submitters to comment on how the Commission's capex forecasts should take into account potential sector-wide deliverability constraints.[28]

Deliverability in the Input Methodologies and ID Determination

8. Deliverability is not expressly referred to in the IMs that apply to DPPs (Parts 3 and 4) because those IMs do not include evaluation criteria for determining opex and capex forecasts.

9. Deliverability is referred to in the CPP IMs (Part 5). It is included in the:

a. information required in Schedule D, which must be contained in a CPP proposal;[29] and

b. matters on which the Independent Verifier must opine under Schedule G.

10. Deliverability is defined in Schedule D as meaning:

> *the extent to which the activities to which the capex forecast and opex forecast relate are likely to be undertaken by the EDB during the next period with reference to the EDB's ability to—*
>
> *(a) source and secure physical resources (such as appropriately skilled personnel and materials) and planning consents from external authorities; and*

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24 Issues Paper at para 3.27 and E74.

25 Issues Paper at para 3.28 and E72.

26 Issues Paper at para 3.29 and E75.

27 Issues Paper at para 3.30 and E76.

28 Issues Paper at para 3.30.

29 EDB IMs, cl 5.4.28.

(b) *prioritise, manage, and undertake the work involved, including the ability to implement any planned step change from historical levels of investment and workload.*

11. Schedule D requires CPP applicants to include in the CPP proposal an overview of the EDB's plans to ensure the deliverability of the capex and opex forecast with particular reference to, amongst other matters, the EDB's ability to implement any planned step change from historic levels of expenditure and workload having regard to:

    a. availability of contractors;

    b. current levels of skilled personnel available to the EDB compared to anticipated requirements over the next period; and

    c. the measures the EDB plans to take to source and secure required additional personnel.

12. Schedule G contains the terms of reference for the Independent Verifier. Amongst other matters, the Verifier is required to:

    a. assess the extent to which the CPP applicant is able to deliver its capex forecast and opex forecast during the CPP regulatory period; and

    b. provide an opinion as to overall deliverability of work covered by the forecast capex and opex categories in the next period.

13. Deliverability is also addressed in the ID Determination, which includes in Attachment A the required contents for Asset Management Plans. Clause 2 of Attachment A states that the disclosure requirements are designed to produce AMPs that, amongst other matters, consider:

    a. the "mechanics of delivery" including resourcing;

    b. the organisational structure and capability necessary to deliver the AMP;

    c. the organisational and contractor competencies and any training requirements; and

    d. the systems, integration, and information management necessary to deliver the plans.

14. Clause 16 states that the AMP must describe the processes used by the EDB to ensure that:

    a. the AMP is realistic and the objectives set out in the plan can be achieved; and

    b. the organisation structure and the processes for authorisation and business capabilities will support the implementation of the AMP.

Is an assessment of deliverability consistent with the s 52A purpose statement?

15. Yes.

16. Section 52A provides that the purpose of Part 4 is to:

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

17. The Commission principally gives effect to the 52A purpose statement by setting allowable revenues equal to forecast costs (including a normal return on capital) in present value terms. Setting allowable revenues such that the present value of allowable revenues is equal to the present value of forecast costs (i.e. NPV = 0) means suppliers have an ex ante expectation of maintaining their financial capital. The Commission's related NPV = 0 and Financial Capital Maintenance principles are intended to ensure that suppliers are incentivised to invest whilst not earning excessive profits.[30]

18. Achieving NPV = 0 / FCM on an *ex-ante* basis requires that the Commission set allowable revenues based on unbiased forecasts of expenditure. Deliverability is a factor that is relevant to forecast costs. If the Commission sets allowable revenues based on proposed expenditure which – whilst prudent and efficient – will not actually be delivered, the supplier will earn a return in excess of its actual costs and a normal return on capital.

19. Earning additional returns is consistent with the s 52A purpose statement if it reflects efficiencies achieved by the supplier. Section 52A(1)(b) provides that suppliers should be incentivised to improve efficiencies and the primary method by which that is achieved is by setting revenue allowances ex ante and then allowing the supplier to retain (at least in part) savings it achieves relative to the expenditure forecasts used to set the price path. However, if the under-spending is due to the supplier's inability to deliver its AMP as opposed to, for

[30] See *Wellington International Airport Limited & Ors v Commerce Commission* [2013] NZHC 3289 at [256] et seq.

example, efficient deferral of investment,[31] then this is unlikely to represent an efficiency in the sense that term is used in s 52A(1)(b).

Is an assessment of deliverability consistent with default price-quality path regulation?

20. As discussed above, deliverability is expressly a factor the Commission considers when assessing a CPP proposal. The IMs do not expressly require the Commission to consider deliverability when setting expenditure allowances under a DPP, but neither do they express forbid it. The question is whether an assessment of deliverability is consistent with the scheme of default price-quality path regulation.

21. Section 53K provides that the purpose of default/customised price-quality regulation is to:

> *provide a relatively low-cost way of setting price-quality paths for suppliers of regulated goods or services, while allowing the opportunity for individual regulated suppliers to have alternative price-quality paths that better meet their particular circumstances.*

22. As the Commission explains in its Issues Paper:[32]

   a. DPPs are to be set in a relatively low-cost way, and are not intended to meet all the circumstances that an EDB may face; and

   b. CPPs are intended to be tailored to meet the particular circumstances of an individual EDB.

23. In practice, the low-cost objective means there is limited scope for individual scrutiny of a particular EDB's circumstances. For example, the Commission's Issues Paper acknowledges that "*bottom-up independent forecasts of capex for each EDB… would be inconsistent with the relatively low-cost purpose of DPP/CPP regulation*."[33]

24. As can be seen from the Commission's approach to deliverability in Schedules D and G of the IMs and Attachment A of the ID Determination, deliverability is both highly individual to each EDB, and requires a complex assessment of a range of factors. For example, an assessment of deliverability requires an examination of each EDB's contracting model or in-source delivery model, contractor capacity, skilled labour availability, systems, and processes to prioritise, plan and deliver capex, amongst other matters. That analysis involves the application of expertise and requires significant judgment. It is not a largely mechanical exercise in contrast to, for example, assessing financeability at the level of

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[31] For example, taking steps to extend the life of assets that enable deferral of replacement and renewal capex while achieving lowest total lifecycle cost.

[32] Issues Paper at para A10.

[33] Issues Paper at para E10.

individual EDBs. For that reason, an assessment of deliverability is unlikely to be compatible with the low-cost objective of DPP regulation, at least in most cases.

25. The Commission's discussion of deliverability in the Issues Paper suggests it is (rightly) focusing on sector-wide factors that impact deliverability. Assessment of sector-wide issues will often by compatible with the low-cost objective of DPP regulation because: (i) the deployment of resource is proportionate given the issue affects all EDBs, and (ii) excluding from DPP scrutiny an issue that affects all or a large number of EDBs may result in a large number of EDBs needing to apply for a CPP, which would mean the DPP regime is likely not relatively low cost.[34]

26. The challenges to deliverability identified by the Commission are sector-wide, or at least plausibly could affect a significant number of EDBs: supply-chain pressures, a tight labour market and competition for delivery resources given many EDBs are forecasting a step-change in expenditure. However, each of these issues is capable of being resolved by a given EDB at the individual level, to a greater or lesser extent, which suggests any moderation of capex forecasts with reference to these sector-wide issues would be low-confidence in the absence of a very detailed and complex analysis. In short, given the way the Commission has approached deliverability assessments in the past, it is difficult to see how the Commission could, consistent with the low-cost objective, incorporate a sector-wide analysis of deliverability into its capex forecasts with a reasonable degree of confidence.

27. There are a number of other considerations that suggest the Commission should be cautious before moderating capex forecasts on the basis of deliverability.

28. First, deliverability only becomes relevant once the Commission has determined that the forecast capex should be allowed. If the Commission proposes to include capex in an allowance, it does so on the basis that it is in consumers' interests for that investment to occur. The deliverability issues identified by the Commission suggest that some capex included in building blocks allowable revenue may not be delivered. However, if the Commission moderates capex forecasts because of concerns with deliverability, that investment definitely will not occur. That denies consumers the benefits of that investment.

29. Second, the problem the Commission has identified is that, if allowed capex is not delivered, EDBs will earn additional profits not through efficiency but through non-delivery. But, when applying the FCM principle, the Commission recognises the asymmetric consequences to consumers of under-investment versus over-investment. If the Commission sets capex allowances that are not fully delivered, consumers will face higher prices, but the price effect is moderated by the IRIS. However, if the Commission reduces capex allowances due to concerns regarding deliverability, investments that would otherwise be made may not occur. Consistent with the Commission's reasoning in relation to WACC percentile, there is a

[34] Issues Paper at para A11.

reasonable prospect the costs to consumers of that forgone investment would exceed the costs to consumers of higher prices.

30. Third, that suggests the Commission's focus in the Issues Paper on additional profits may be misplaced. The greater risk to consumers from sector-wide deliverability challenges is that prudent and efficient investments may not occur. That in turn suggests that the Commission's focus should be on ensuring that the regulatory settings support EDBs in delivering their AMPs, including by enabling supplier responses to deliverability challenges.