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Vector submission on DPP4 Issues Paper dated 2nd November 2023

1. This is Vector's ('our,' 'we,' 'us') 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.

2. In the table below we have summarised our key recommendations for the Commission going forward with its DPP4 reset process. In the Appendix we have incorporated the Commission's set of questions, referencing where the answers can be found in our submission.

Priority issue	Key Vector recommendations
Process	▪ The Commission must inform stakeholders of dates and topics for any discrete issues papers and information requests in early 2024 as soon as reasonably practicable. ▪ The Commission must bring forward IAENGG's final report for EDBs to have some opportunity to incorporate IAENGG's feedback in their 2024 AMPs due 31 March 2024.
Financeability	▪ Early in 2024 the Commission must detail how it will consider financeability when setting the DPP. This must include how key regulatory mechanisms will be set including how P0 changes will be implemented as well as: ○ Revenue smoothing (within-period smoothing or revenue caps); and

	○ Wash-up account drawdown specifics given inflation has seen wash-up balances within DPP3 grow more than previously observed. ▪ The Commission must ensure that the uncertainty created by the floated changes by the Electricity Authority (Authority) in relation to capital contributions, has no unintended consequences on EDBs' abilities to finance DPP4 expenditures and invest in electrification. ▪ The Commission should take stock of what other jurisdictions are doing around financeability to inform best practice in New Zealand. ▪ The continued significance of financeability is not just in section 53P (8)(a) and reference to "financial hardship" to the supplier. Financeability and the confidence upon which increased investment translates to increased cashflows goes to the heart of Part 4's statutory purpose - the incentive to innovate and invest. ▪ Part of the Commission's logic in rejecting calls for financeability to be expressly addressed within an existing or a new input methodology (IM) is that a customised price-quality path (CPP) application is available for individually impacted EDB businesses. We do not accept this logic. Without knowing with confidence how the Commission intends to approach financing and cashflow considerations (as is the objective of IMs) it would seem highly unlikely that regulated EDBs would apply for a CPP to address financeability concerns.
Consumers	▪ The Commission must not self-determine what would be considered a price shock to consumers. It is important to examine price shocks in the context of the household budget and what can (and has) occur(red) in workable competitive markets (e.g. mortgage rate increases, grocery bill inflation, petrol price volatility post Ukraine invasion etc). The proportion of household expenditure on electricity, relative to other expenditures, is highly relevant. ▪ Consideration of broader macro societal issues such as energy affordability and energy hardship are clearly the role of the government and not the Commission. ▪ The Commission needs to consider the impact on consumers' overall "energy wallet" in its consideration of price increases.
Capex framework review	▪ The Commission must not set the framework without engagement with stakeholders. This could be achieved by providing previews of their emerging views at least a week ahead of a capex framework workshop. This will ensure that EDBs can properly engage on the proposals for the 'design' and 'adjust' phases and ascertain what the emerging views mean for their own circumstances. ▪ The Commission needs to add additional flexibility mechanisms to what it allowed for in its IM Review. Such as Use-It-Or-Lose-It (UIOLI)

	funding for resilience spend, consider storm response costs as eligible for 'pass-through' or a targeted innovation scheme for flexibility expenditure. These flexibility mechanisms must also be considered along with the capping of revenues. There is little point in having these mechanisms if the additional revenue they provide is locked up in a wash-up account and the additional cashflow not able to be accessed for a considerable period of time after the expenditure takes place.
Resilience expenditure	▪ In parallel to this submission, EDBs have been asked via a s53ZD for forecast capex and opex expenditures. ▪ Vector has identified but not included any potential resilience capital expenditure in its s53ZD information response. ▪ There continues to be much uncertainty about what level of resilience expenditure may be deemed appropriate by lines companies, customers and/or Government. For example, we await overdue tree regulation reform which, if it eventuates, would see Vector reshape its proposed resilience expenditure. Additional expenditures at this time also seem challenging both for the significant uncertainty that exists over the Commission's treatment of allowed future revenue adjustments and the price impact consumers are already facing by virtue of higher inflation and interest rates.

Opex base step trend approach	▪ The Commission's opex base step and trend approach must be reviewed – it does not account for costs that are genuinely new to DPP4, that have arisen in DPP3 but will have step changes in scale over DPP4 or are hard to assess within a low-cost regime and where the level of cost would not justify or meet the criteria for a reopener or CPP.
	▪ The Commission's approach to using capex as a driver for non-network opex, must go further and start using EDBs' non-network opex forecasts instead of a base step trend approach.
	▪ We recommend that the Commission provides clarity on the process for opex step changes in the DPP reset process as it is not at this stage clear. This includes:
	    o When and how EDBs apply for an opex step change; and
	    o What information EDBs need to provide for step changes especially those that are hard to 'robustly verify' and do not meet the criteria for a reopener, CPP or innovation project allowance (IPA)/ innovation and non-traditional solutions allowance (INTSA) application.
	▪ We recommend that the Commission considers a targeted innovation scheme for EDBs to access expenditure related to flexibility services

	and/or when that payment is to a particular flexibility provider the Commission should consider as a pass-through cost.
Quality standards and incentives	▪ We recommend that the Commission revisits its IM decision to not introduce regulatory sandboxing to cater for innovation trials which may impact SAIDI/ SAIFI. ▪ The Commission should consider a reliability standard change by carving out or normalising SAIDI and SAIFI for any instances of shutdowns to manage bush fire risk. ▪ The Commission must reconsider its allowance for major event days when setting quality standards. This must be done looking forward not backwards as history will not be a good predictor in this case as climate change will result in a level of major events not seen in past years. The Commission must work with weather agencies in forming its view. ▪ We recommend that at a minimum, the Commission considers re-adopting the '2 out of 3 rule' approach to breaches. ▪ The Commission must consider the carving out of SAIDI and SAIFI minutes solely as a result of emergency services prohibiting access to the outage site. ▪ We are encouraged that the Commission is considering a carve out for outage minutes resulting from an event caused by a flexibility provider. We support a carve out for these types of events. This should also cover when the network operator has issued a dynamic operating envelope (DOE) and third parties have failed to comply. ▪ The Commission will be aware of our previous submissions that the aggregate SAIDI/SAIFI measures are not particularly consumer centric. The potential to reconsider quality settings more radically (such as disaggregating quality metrics by geography or network characteristic) have not been picked up by the Commission. However, we remain of the view that there exists considerable potential to better measure quality with a greater focus on customers.
Productivity	▪ The Commission must find new ways to look at productivity which considers EDB outputs that are not considered in their productivity modelling. ▪ The Commission must ensure any productivity analysis it undertakes adjusts for changes in legislation e.g. Health and Safety at Work Act (HSWA), regulation e.g. local council traffic management, accounting treatment changes e.g. software as a service (SaaS). ▪ Opex used in the Commission's productivity analysis must only consider opex paid for by consumers i.e. that is funded through revenues and therefore must adjust for IRIS.

Other incentives, uncertainty, and innovation	▪ Incentives are needed for energy efficiency and demand-side response: a targeted innovation scheme for flexibility services should be introduced. ▪ The Commission must look at expanding the uncertainty mechanisms at their disposal. ▪ The Commission has hinted at holding a targeted workshop on innovation in the new year. We believe this is a good idea and look forward to participating with the aim of either improving the IPA/ INTSA or bringing in a new mechanism modelled on ideas from overseas.

The DPP4 process needs to be pro-active ahead of the draft decision

3. The process run by the Commission on DPP4 through the second half of 2023 has not been adequate, is a source of regulated supplier frustration and needs to improve going forward. Vector remains committed to working with the Commission to meaningfully consider and address increasing challenges to the regime's application. We continue to be of the view that formal written consultations (the Commission's favoured form of consultation) may not be the best means to engage and to find solutions. As we have consistently maintained for several years, the ability to workshop, collaborate, test positions and assumptions, and work through the practical application of highly complex regulation is far more likely to deliver genuine engagement and a practical understanding of positions, problem definition and the testing of alternative solutions.

IM review overlap

4. There are key decisions from the IM review that will have a huge bearing on the DPP4 process. The main one for Vector is financeability. We have consistently raised it as an important issue since the IM review Process and Issues Paper and Draft Decision-Making Framework Paper were published back in May 2022 (and prior to that Vector has long raised concerns about the impact of RAB indexation which already backends significant amounts of cashflow for EDBs). We are extremely concerned that the Commission did not address suppliers' concerns on financeability in their IM review. Instead, they chose to "kick this down the road" to DPP4. The IM's were the correct place to address financeability as a key purpose of the IMs is to create regulatory certainty.

5. New Zealand's EDBs are about to embark on a period of sustained and increased investment in their networks to enable net zero 2050. To do this these EDBs will need to access both local and international capital markets. These markets need a level of certainty in the regulatory regime before providing that capital. The Commission has missed a great opportunity to have provided that certainty. By deferring to DPP4 the Commission continues to maintain its discretion on how and when it will consider financeability. This provides little or no certainty and harms the ability of suppliers and their investors to determine whether future cashflows can sustain the expected returns to investors providing the capital to support the levels of investment that are required.

6. Exogenous changes including inflation and rising interest rates throughout DPP3 will result in a direct and significant uplift in the value of EDBs regulated asset bases and the weighted average cost of capital (WACC) used for DPP4. Even in the absence of the need for EDBs to invest to facilitate decarbonisation and fortify their networks to withstand the increase in extreme weather events driven by climate change, revenue allowances for DPP4 will greatly exceed those set in DPP3.

7. Disappointingly the IM review's draft decision and subsequent final decision was not to introduce a financeability assessment into the IMs[1]:

   "Our draft decision is not to adopt a financeability test in the IMs because we do not need an explicit test in the IMs to consider financeability. We can already consider, and indeed have previously considered, financeability where relevant and not inconsistent with promoting the Part 4 purpose."

8. Following the draft determination, Vector put in an Official Information Act (OIA) request for documents from the Commission in relation to financeability i.e. any information or documents that relates to the Commission considering financeability in contexts other than the Aurora CPP decision paper (including the actual modelling undertaken, if any).

9. We sought external advice from Oxera Consulting (UK) LLP on the information received which concluded that the financeability assessments historically carried out by the Commission raise fundamental concerns[2]. We wrote to the Commission on 8 November 2023 to outline these issues, which included:

   a. The test for negative free cashflows is not well-specified;

   b. The 1.0 threshold for the interest cover ratio is too low;

   c. The Commission does not model how cash requirements affect leverage in a dynamic way, which is key for financeability assessments; and

   d. The Commission does not assess the effectiveness of (any potential) remedies in a quantitative way.

10. We also highlighted the importance of including a dividend yield to the equity holder as a financeability test requirement. The Commission's financial model assumes a return to equity

[1] Paragraph X39, https://comcom.govt.nz/__data/assets/pdf_file/0026/318626/Part-4-IM-Review-2023-Draft-decision-Financing-and-incentivising-efficient-expenditure-during-the-energy-transition-topic-paper-14-June-2023.pdf

[2] Oxera Consulting (UK) LLP, Cashflows and Financeability: Review of the NZCC's approach to the financeability assessment, 15th September 2023

holders and therefore a financeability test should show that the notional firm can generate the returns required to provide that allowed equity return.

11. Disappointingly the Commission replied to our letter to explain that our letter and external advice would not be taken into consideration for the IM review final decision.

12. Instead, we understand that a financeability paper will be published in late February 2024. This, in our view, is too late in the DPP process. Boards of directors will be reviewing 2024 AMPs before then without understanding what decisions have been made in relation to some crucial aspect of the regime including:

    a. The P0 adjustment; and

    b. The revenue smoothing mechanism specificities (intra-period smoothing or price cap).

13. The Commission's approach to addressing calls from stakeholders throughout the IM Review and now the DPP reset process is deeply concerning. Suppliers are about to enter a period of significantly increased investment. How this investment is financed is fundamental. The IMs have at their core to promote certainty. Without confidence around this cashflow and ability to finance, suppliers will have few options other than to dial back their capital programmes to manage that uncertainty risk.

14. The Commission needs to also consider that it is unlikely that significant "financial hardship" of an EDB will occur in practice. No prudent operator would systematically spend at a level that would result in placing themselves into financial difficulty. Instead, they would simply elect to halt investment in the first instance. It is hard to see how suppliers not investing at a level required to achieve the energy transition, to manage uncertainty risk brought about by inadequacies in regulation, is in the long-term interests of consumers. At the heart of sector concerns with the Commission's laissez-faire approach to how it intends to consider financeability - where cash funding will only be considered at the Commission's full discretion in the context of a DPP reset (or perhaps CPP application) to, as yet undefined metrics, process and correction mechanisms. All of this is of course further to the long-standing challenge already imposed through indexation which back-ends EDBs cashflows and provides a large portion of equity return via a non-cash revaluation of the asset base.

15. Part of the Commission's logic in rejecting calls for financeability to be expressly addressed within an existing or a new input methodology is that a CPP application is available for individually impacted EDB businesses. We do not accept this logic. Without knowing with confidence how the Commission intends to approach financing and cashflow considerations (as is the objective of Input Methodologies) it would seem highly unlikely that regulated EDBs would apply for a CPP to address financeability concerns. Vector restates that a clear case for financeability remains for inclusion within the input methodologies to provide the certainty and confidence on how the Commission would assess and address financeability concerns in the future. Without this, Vector cannot see how a CPP is an answer to significant and consistent financeability concerns now raised across the sector.

16. There is also a clear process issue that needs to be addressed in regard to leaving decisions around the financeability to the DPP. The Commission makes the bold assumption that suppliers hedge their debt for the DPP in the "on the day" window it uses to set the cost of debt. This window takes place before the Commission makes its final DPP decision which we assume will include its decisions around financeability. How do suppliers know what level of debt to hedge in the "on the day" window if there is no certainty on financeability of cashflows at the time that hedging needs to be undertaken?

17. **We urge the Commission to urgently bring forward its in-person and formal engagement relating to financeability as a fundamental aspect of the regulatory regime. This is because we consider the Commission's position is now undermining investor and regulated supplier confidence at the precise time forward-looking planning and enabling infrastructure is being demanded by customers, Government and society.**

Inflation

18. The Commission is missing an important topic in its Issues Paper; the reset process needs a special workstream on inflation. Having been caught out so many times, the Commission needs to find ways to minimise the impacts of inflation forecasting errors as well fully understand the business impacts of recent inflation spikes caused by demand and supply shocks not previously experienced under the Part 4 regime.

19. The sector can no longer let inflation dictate so many inputs to the regime that have severe repercussions on suppliers and consumers alike. Combined with widespread infrastructure plans across so many different utilities, there is real pressure on resources that the Commission needs to acknowledge and allow for. EDBs do not control inflation and therefore should neither be incentivised or penalised because of its volatility.

20. The Commission's track record at forecasting inflation has been extremely poor resulting in, period on period, large swings in revenues with these impacts being borne by suppliers and consumers unnecessarily. The current period of sustained high inflation ought to provide an important trigger for the Commission to reconsider its approach to inflation forecasting. The Commission ought not to approach DPP4 with a "business-as-usual" approach to inflation, when considering forward allowances.

21. We continue to question the inappropriateness of adopting Reserve Bank of New Zealand's (RBNZ) inflation forecasts and projections despite these being "set and forget" beyond 6 months and wholly unfit for the purpose the Commission utilise them for.

22. John McDermott from Motu provided his views on inflation forecasting in a memo[3] submitted with during the IM review draft decision consultation. He disagrees with the Commission's view that it is appropriate to use the RBNZ forecasts as a basis for a five-year ahead inflation forecast to index the RAB: "The fundamental problem with using the RBNZ projections is that they are a tool designed for near-term planning and signalling, not for long-term regulation."

23. He explains that forecasting inflation, even a few months ahead, is challenging. Knowing where inflation will be over the next five years is immense. The problem is particularly acute now. The existing long-term inflation risks are influenced by some large and persistent secular global forces whose impact on inflation is very uncertain, if not unknowable.

24. The solution he proposes is that rather than use the Reserve Bank forecasts, a more valid regulatory approach would be to remove the inflation uncertainty altogether: "The first best option is to stop indexing of RAB to forecast inflation and leave the RAB not linked to any inflation forecast. Such a change would remove a great deal of unnecessary uncertainty from the process, improving future incentives for investment."

25. The performance of the inflation forecasting framework in previous periods has been demonstrably poor. For the reasons we set out, the materially better approach would be to dispense with indexation altogether.

26. Indexation of the RAB was the subject of a separate OIA request by Vector in relation to the Commission's original 2010 decision not to index Transpower's RAB. In the recent IM review the Commission justified its decision to not index the Transpower RAB on the basis that Transpower had a substantial programme of 'catch-up' capex. Our request was for, any information or documents (beyond the published materials) that:

    a. further explained the rationale and the Commission's reasoning/analysis/evidence in support of that conclusion; and/or

    b. the extent to which the Commission considered/evaluated the intergenerational effects of not indexing Transpower's RAB (back in 2010).

27. We derived from the OIA material received, that the Commission's overwhelming reason for adopting an unindexed RAB approach for Transpower was to provide improved cash flow for Transpower at a time they were faced with significant increased investment. The Commission's decision was not influenced in anyway, as was suggested during the IMs process, that the investment was a catch-up of investment that should have taken place in the past.

[3] https://comcom.govt.nz/__data/assets/pdf_file/0018/323172/Vector-Motu-July-2023-memorandum-on-inflation-forecasting-Submission-on-IM-Review-2023-Draft-Decisions-19-July-2023.pdf

28. The Commission's past statements on indexation also acknowledge that, while indexation is its preferred approach, it is appropriate to depart from that default if there are "specific circumstances that are likely to merit an unindexed approach". The specific circumstances in the case of Transpower were its increased investment requirements and therefore the benefits of bringing forward cashflows. That principle was articulated in the context of the Commission's discussion of Transpower, but it is a principle of general application. There is nothing in the Commission's past statements that supports the conclusion that non-indexation was a solution reserved only to Transpower.

29. Given Aotearoa New Zealand's decarbonisation targets which will require increased capital expenditure, there is clearly a significant case for non-indexation for EDBs based on the accepted factors used in assessing whether to un-index Transpower.

30. **Regardless of whether the Commission decides to formally take account of our letters in response to the OIA requests, we urge the Commission to reconsider its position on financeability.**

Section 53ZD Notices

31. As indicated by the May 2023 Process Paper, EDBs were expecting the Notice requests in late September or early October. Instead, we received them on 10 November, squeezing the deadline to respond until 21st December. Whilst it was positive to be consulted on the draft Notice, the Commission could have put out this request much earlier to avoid:

    a. Running the Issues Paper consultation in parallel; and

    b. Squeezing all the discrete issues papers and stakeholder workshops into early 2024.

32. We understand that the expenditure forecasts provided by the Notices will inform the Commission's draft decision, yet the justifications and drivers underlying these figures will be assessed by IAENGG from EDBs' 2023 Asset Management Plans (AMP). It is unclear whether IAENGG will also be reviewing the information provided in the Notices (i.e. the bridge between the 2023 AMP forecasts and draft 2024 AMPs forecasts) or this exercise will be left to the Commission. We suggest that all information must be reviewed by both parties for a sound assessment to be made.

33. While the Notices to provide up to date forecasts are a new addition, the Commission has indicated and must follow through on the premise that our 31 March 2024 AMPs will be reflected in final decisions (and where possible in the draft).

34. For operational expenditure (opex) we note an inconsistency in the material variances request. Given that opex is assessed against the base year, we believe that the material variances should have been ascertained using that same method i.e. DPP4 forecast average against RY23 (base year for draft decision for which we have actuals). On this basis we ask the Commission below to define an appropriate and clear process for opex consideration for DPP4

and, in particular, set out a clear process for EDBs to set out areas of expenditure where "step and trend" may not be appropriate. At a minimum, if the Commission simply undertakes the same step and trend approach that they did in DPP3, then this output must be compared to EDBs' AMPs to identify where the results are different, and those differences then explained. The mechanical nature of the base step and trend approach does not allow for significant changes in opex that may result from transactions / activities that occur within the DPP4 period. For example, if a supplier is renegotiating its field service contracts part way through the DPP period this could have a significant impact on costs that would be unlikely to be picked up by the base step and trend approach. Renegotiations could lead to previous prices within those contracts escalating significantly as they may have been set many years prior.

35. The s53ZD for quality of supply (QoS) was not immune from issues also. We have had to accommodate our reporting methods to fit the template and have outlined our assumptions (in the cover letter to our Notice response), with certain categories being left open to interpretation.

36. We recommend that the Commission informs stakeholders of precise dates and topics for discrete issues papers in early 2024 as soon as reasonably practicable. Several items are currently marked as "early 2024" in the Issues Paper, therefore providing a timeline early will help (especially noting that the Electricity Authority (Authority) will be consulting on distribution pricing around this time).

IAENGG review

37. Vector welcomes the independent review by IAENGG, including the early engagement on our 2023 AMP in our meeting on 3 October 2023. As we outlined in our response[4] to the 'Workshop on forecasting and incentivising efficient expenditure' in late 2022, the Commission should rely on EDBs' forecasts where they can demonstrate their robustness. It was, and still is, our view that relying on historic information to predict the future is no longer fit for purpose given the energy transition we are on.

38. We must however point out the substantial disconnect in the process whereby EDBs will receive feedback from the IAENGG review in draft form in January (we understand) and final form in March 2024. This leaves very little time (if any) for EDBs to take on board and incorporate this feedback in their 2024 AMPs due at the end of March.

39. **We recommend that the Commission brings forward the final report for EDBs to have some opportunity to consider and incorporate the IAENGG feedback into AMP24**

Stakeholder workshops

40. The Commission must learn from the IM review workshops where they:

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[4] https://comcom.govt.nz/__data/assets/pdf_file/0021/314445/Vector-Submission-on-Expenditure-Forecasting-Workshop-16-December-2022.pdf

a. Held workshops as a replacement for discrete issues papers;

b. Issued requests for feedback with dozens of questions with only two weeks to respond; and

c. Provided workshop slides only a couple of days ahead of time – leading to minimal engagement within those workshops.

41. We believe the workshops should be targeted on specific issues and given enough time to fully interact with the topics to allow productive discussions to give way to solution setting. The topics we would like to see focussed engagement on are:

a. Financeability;

b. Productivity;

c. Resilience expenditure;

d. EV growth uncertainty;

e. Simpler means to address uncertainty without drawn out re-opener and CPP applications;

f. Impacts of future weather events; and

g. Innovation.

42. We recommend that the Commission's DPP4 workshops provide papers and questions at least a week ahead of the workshop and give at least three weeks to consult on the workshop material if they are not accompanied by a discrete paper.

Decisions around financeability are crucial and must be brought forward

Financeability must be considered (if not in the IMs) in the DPP

43. Back in July 2023 PWC wrote that the Commission's decision not to include a financeability test in the IMs was not compelling[5]. The s52R purpose of the IMs is to promote regulatory certainty. One of the largest sources of uncertainty at present is the ability of electricity distributors to fund the investments needed to facilitate the energy transition in Aotearoa New Zealand.

[5] Page 7, https://comcom.govt.nz/__data/assets/pdf_file/0019/323173/Vector-PWC-Including-a-financeability-test-in-Input-Methodologies-for-electricity-distribution-businesses-Submission-on-IM-Review-2023-Draft-Decisions-19-July-2023.pdf

44. PWC also believe that a financeability test will enhance the s52A purpose to incentivise investment at a time when there is significant amount of investment in electricity network infrastructure needed to meet increased demand and improve resiliency, as New Zealand becomes more reliant on electricity to meet its energy needs.

45. The Commission's IM review final decision was not to introduce a financeability test while this would have been the most appropriate time to address this matter the Commission must not now loose the opportunity to reconsider its decision by introducing a financeability test at the DPP reset. We look forward to engaging once again on this topic in the financeability paper in February 2024.

Building Blocks Allowed Revenue (BBAR) recovery

46. The Commission in its decision on the IM framework identified ex-ante real financial capital maintenance (FCM) as a fundamental economic principle for the Part 4 regime. When considering smoothing to mitigate price shocks, the Commission must be mindful of this key economic principle and ensure that the entire revenue allowance (including wash-ups) be recovered within the DPP4 regulatory period (i.e. no planned deferral of revenues between DPP4 and DPP5).

47. It is also important that the Commission is consistent with its past practices when implementing P0 adjustments between DPP periods. It is important to note that all prior DPP resets have resulted in unconstrained price resets that immediately implement the regulated revenue allowance. This has been the case despite historic calls from suppliers to smooth these impacts (including formal legal challenge and appeal on the need for a specific IM on the Starting Price Adjustment) the Commission chose to apply unconstrained P0 adjustments. It is therefore incumbent that the Commission is even handed and consistent in its application of the P0 i.e. applies its historical practice.

48. To not apply consistency undermines confidence and certainty in the regime going forward and goes against the heart of Part 4 – to promote certainty for regulated suppliers and consumers. Regarding the setting of revenue caps that apply within a DPP period the Commission also needs to be mindful of the basis it has set caps in the past. In the DPP3 reasons paper the Commission states that its expectations are that the revenue cap it set would bind infrequently[6]. Therefore, any caps to apply within DPP4 need to be set on the same basis or strong arguments presented as to why the "bind infrequently" rationale for the cap in DPP3 no longer applies in DPP4.

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[6] Paragraph H68.3 of the DPP3 reasons paper available here https://comcom.govt.nz/__data/assets/pdf_file/0020/191810/Default-price-quality-paths-for-electricity-distribution-businesses-from-1-April-2020-Final-decision-Reasons-paper-27-November-2019.PDF

49. The intergenerational consequences also need to be weighed when setting caps especially if these caps were to have the effect of pushing revenues out beyond the DPP4 period. Shortfalls in revenue that are recovered in future periods are effectively a cross subsidy of today's consumers.

50. Another issue with the capping of revenues that then results in wash-up balances is that it magnifies the back ending of cash flows issue caused by the indexation of the asset base. This means that investors funding investments today need to wait a considerable time until those investments deliver a cash return. This cannot be consistent with promoting investment for the long-term benefit of customers.

Capital contributions

51. EDBs face the prospect of large new customers (data centres, public EV charging stations, embedded wind and solar farms, etc.) connecting at times and in places that are difficult to predict. At times this may necessitate re-opening an EDB's price-quality path – a costly and time-consuming process that will delay connections considerably and, potentially, the delivery of benefits from electrification/decarbonisation.

52. If connection costs are not met by connecting parties, this also 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. An overwhelming number (90% of all New Zealanders aged 18+) do not support the costs of new EV connections being borne partly or fully by all customers across network pricing[7].

53. At Vector we have a policy of access seekers paying for their cost to connect to the network which ensures that existing customers are not worse off as a result of the new connecting party. To achieve this:

    a. We apply a standard $/kVA charge to deal with system growth costs of new connections;

    b. New connections pay for their sole use assets i.e. the costs of their connection assets. However, we also, by mutual agreement allow customers to do their own trenching, civil works, reinstatement and laying of duct, i.e., if they believe they can undertake a project more cheaply themselves; and

    c. We pass on to connecting parties' costs beyond our control which are many of the most significant costs of connection (traffic management, consenting etc.) which are imposed by others (NZTA, local councils).

[7] A nationally representative survey of 1000 respondents conducted by Dynata in 7-12 December 2023

54. Capital contributions also have one vital broader implication that needs to be highlighted: they reduce EDBs' financing requirements. Without those contributions from connecting customers, EDBs would need to finance those works themselves (for recovery via price-quality paths). That additional burden could come at a time when EDBs are already facing financing challenges from the substantial investments required to enable electrification. And, at a time when the Commission shows reluctance to provide suppliers with any certainty on how those financing challenges will be considered within the current regime.

55. As we stressed earlier in our submission, financeability is a key concern for EDBs and could compromise our ability to invest at the right levels required by customers and stakeholder as undertaking that investment could impinge on maintaining satisfactory credit metrics and any move to limit capital contributions would worsen those credit metrics and magnify the extent of the financing challenge.

56. The Part 4 purpose requires the Commission to promote the long-term benefit of consumers of regulated services. The Commission must do this by promoting the outcomes consistent with those produced in workably competitive markets – namely, that the suppliers of these services have incentives to innovate and invest, including in replacement, upgraded, and new assets.

57. EDBs do the heavy lifting on annually connecting tens of thousands of consumers. This involves managing a variety of third parties, complex and varied sites to work on (green-fields and brownfields each having their own complications), and high consumer/ developer expectations. For Vector, new connections are generally between 12,000 to 16,000 connections per year across the greater Auckland area[8]. This is done with few complaints from connecting parties as can be seen by the small number of Utility Disputes Limited (UDL) complaints[9], all while the number of connections faced by EDBs is growing rapidly.

58. The Authority should not (and would be acting in error) be so bold as to assume reopener mechanisms in the Commission's regime for so many EDBs can simply alleviate the challenge in accurate forecasting new connections, in particular large point-loads. It is unlikely that reopeners could respond in time to meet the requirements of most access seekers and significant uncertainty would remain over the outcome of any reopener process.

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[8] Vector had 12,478 new connections in 2020; 13,854 in 2021; 13,437 in 2022; and 15,509 in 2023 - see Vector's Electricity Information Disclosures here https://www.vector.co.nz/about-us/regulatory/disclosures-electricity/financial-and-network-information

[9] In the past 5 years UDL has recorded 102 complaints about delays in setting up new connections New Zealand-wide, 69 are about retailers (0.7% of retailer total), 33 are about EDBs (2.6% of EDB total). See UDL submission to the EDB Targeted ID Review Process and Issues Paper, 20th April 2022, p.3 available here https://comcom.govt.nz/__data/assets/pdf_file/0016/282121/Utilities-Disputes-Limited-Submission-on-EDBtargeted-ID-review-process-and-issues-paper-20-April-2022.pdf

59. The ability to offer flexibility to access seekers where they can balance cost versus quality of service is relatively limited due to the physical nature of the network unless the Authority is envisioning some form of firm right for the management of discretionary load by EDBs where an access seeker agrees to be "first off" in the case of an EDB needing load management to resolve a network constraint.

The Commission must ensure that any intended code changes by the Authority in relation access pricing methodologies that have a flow on impact to capital contributions, has no unintended consequences on EDB's abilities to finance DPP4 expenditures.

Financeability overseas

60. In the case study 1 below, we have summarised the ongoing consultation in Australia around regulatory financeability changes.

61. Although the proposed changes relate to transmission projects, we believe that the same logic applies here in Aotearoa and to distribution. Ensuring financeability arrangements are in place, provides investors with certainty and with businesses to keep up with the demands of electrification.

62. **We recommend that the Commission urgently take stock of what other jurisdictions are doing around financeability to inform best practice adoption here in New Zealand and provide much clearer guidance on regulated EDB cashflow profiles for DPP4 including the regulated WACC rate reset from 1 April 2025.**

Case study 1: Accommodating financeability in the Australian regulatory framework[10]
In June 2023, the Australian Energy Market Commission (AEMC) published a consultation paper on a rule change request from the Commonwealth Minister's (Minister) to accommodate financeability in the regulatory framework. The AEMC is investigating options to improve financing arrangements for the delivery of new transmission projects needed for the transformation of the energy system and a cleaner energy future. The rule change requests focus on the timely and efficient delivery of projects and follow recommendations released through the AEMC's recent Transmission Planning and Investment Review, proposing a number of changes to the national energy rules (NER). A rule change on 'concessional finance' could see the benefits of financing for transmission projects sourced through government programs, such as the Commonwealth Government's Rewiring the

[10] Consultation begins on new finance reform for transmission projects following AEMC review | AEMC

Nation Fund, passed back to consumers in the form of lower network charges, either now or in the future, easing hip pocket pressures.

A separate request regarding 'financeability' could see changes to the revenue-setting framework for transmission projects, allowing variation of the 'depreciation profile' of assets, supporting the business' ability to raise finance but with no change to the revenue earned over the life of the asset.

The proposed financeability changes would provide transmission businesses and investors with greater certainty to develop projects sooner, so that the system can keep up with the pace of transition and customers can enjoy reliable and secure power at the lowest possible price.

Consumer impact must be central to decision making

Consumer price shocks

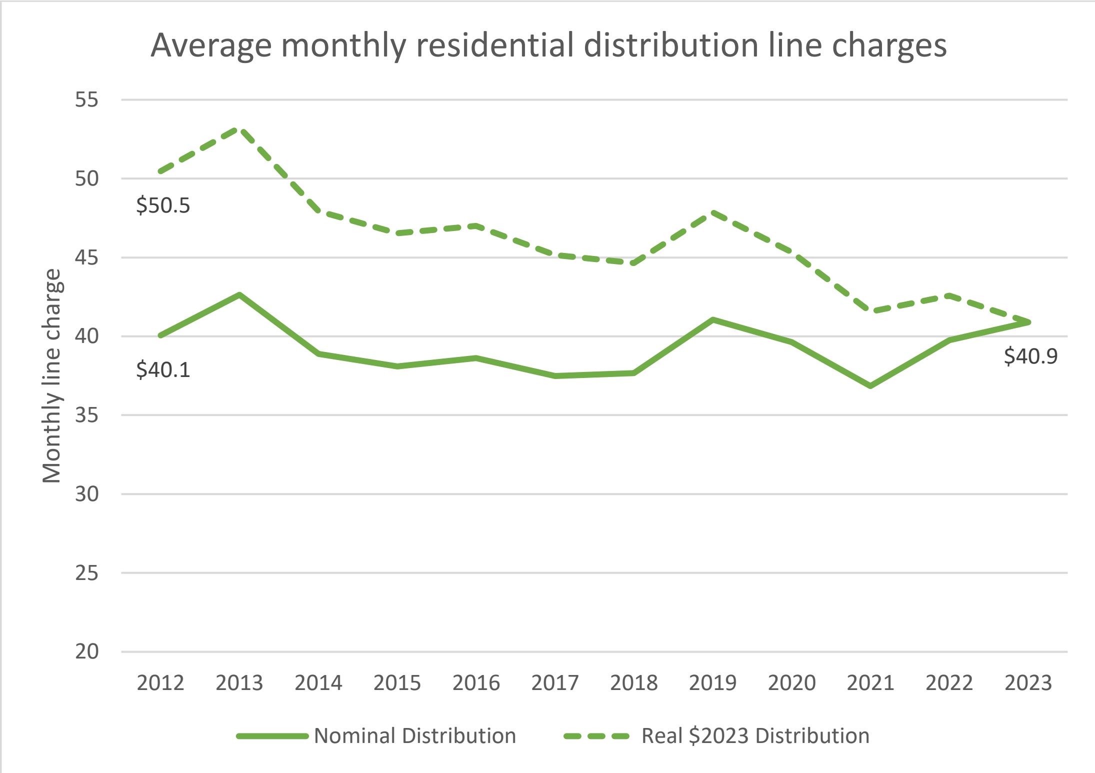
63. Vector continues to place our customers at the centre of our decision making, balancing reliability and resilience investments with impacts on affordability for customers and decarbonisation. How electricity is generated, transported, stored, traded, and consumed is rapidly changing and will continue to evolve. These changes are driven by customers, and so Vector employs a data first strategy, complemented by direct engagement, to build deeper understanding of customer preference and impact. This strategy is crucial, given the scale of our customer base and operations, noting that in Auckland many suburbs are the size of New Zealand towns and small cities.

64. An example of how this strategy informs our work is our customer pricing methodology, which is informed by data analysis that examines billing and half-hourly electricity use data across different customer parameters such as deprivation deciles. This enables pricing decisions to be made with detailed knowledge of aggregate and customer level impact, helping to avoid negatively affecting financially vulnerable customers.

65. Consumer prices also need to be considered in an historical context as consumers have benefited considerably from DPP resets that have reduced prices. Graph 1 below represents Vector's average monthly residential line charge (distribution element only; real and nominal)) from 2012 to 2023 derived from our EID Schedule 8[11]. It shows that over the last decade consumer's distribution charges have in fact decreased in real terms.

Graph 1: Vector's average monthly residential distribution line charge 2012-2023 with 2023 price base

[11] EIDs are available on our website here https://www.vector.co.nz/about-us/regulatory/disclosures-electricity/financial-and-network-information



66. The Commission's emerging view is to assess price shocks for consumers using the real change in aggregate distribution revenue from year-to-year.

67. The Commission has a fine balance to navigate between price shocks to consumers, undue financial hardship of suppliers and the incentive to invest. For example, the annual limit on price increases (10% in DPP3, now referred to as "revenue smoothing limit" in the draft IMs) are estimated by Frontier Economics to lead to billions of unrecovered revenues for EDBs if applied into DPP4:

> *"As a consequence of the annual price limit binding, our indicative modelling suggests that nearly $1.5 billion of revenues could be left unrecovered by the end of the DPP4. This unrecovered revenue would accumulate in the revenue wash-up account to be recovered in subsequent regulatory periods.*
>
> *The modelling indicates that much of this revenue would be recovered over DPP5. However, by the end of that period, more than $860 million could remain unrecovered by the Big 6."*[12]

[12] Paragraphs 150-151, https://comcom.govt.nz/__data/assets/pdf_file/0015/323106/27Big-627-EDBs-Frontier-Economics_-A-review-of-the-limit-on-EDB-price-increases-Submission-on-IM-Review-2023-Draft-Decisions-19-July-2023.pdf

68. The Commission must weigh price shocks to consumers, undue financial hardship for suppliers as well appropriate incentives (including ability) to invest. Significant delays between investment and increased cashflows to support such investments will curtail investment. Consideration of broader macro societal issues such as energy affordability and energy hardship need to continue to be the role of the government and not the Commission.

A whole system cost approach

69. Regulation of the energy system in New Zealand is siloed. Achieving an efficient energy transition at least cost to consumers requires consideration of costs across the whole supply chain. A narrow focus on the cost impact on only one part of the supply chain (e.g. just distribution or just transmission) will not provide the true picture of the costs and benefits of a particular investment.

70. We recognise the Commission's statutory role is overly constrained by being focussed on consumers only in the relevant narrow market (e.g. distribution customers). However, there still needs to be acknowledgement by the Commission of the broader overall impact if the long-term interests of consumers are to be truly understood and met. Work commissioned by Vector and authored by Frontier Economics in London discusses how the UK Government, including Ofgem, is now considering its regulatory regime in light of the need to target better whole-of-energy-system costs for consumers[13]. The current Part 4 regime looks increasingly "stuck in the mud" by artificially focussing only on a silo when it is the end customer bill, made up of components from across the supply chain, that ultimately impacts the customer.

71. It is also important to bear in mind that the benefits of electrification extend beyond benefits to consumers in their capacity as consumers of the regulated service. For example, while investment to support the uptake of EVs will likely increase network costs in the short-term it will also allow consumers to significantly lower their petrol costs (or total energy household costs or "Energy Wallet"). It will also assist in reducing central government international carbon offsetting obligations so has an NZ Inc value that the Commission risk failing to recognise.

72. Accordingly, we encourage the Commission to remain cognisant of costs and benefits across the energy system. Otherwise, there is a risk the real impact that potential DPP changes (and resulting investment behaviour) would have on consumers in practice is not considered.

73. We consider it necessary to acknowledge that funding increased electrification will inevitably involve network price increases for consumers in the short term. While neither the Commission nor industry should take this lightly and all stakeholders should work to minimise price increases as much as possible, some increase is unavoidable to deliver the energy transition given the large-scale investment needed.

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[13] Frontier Economics, 25 March 2021, https://blob-static.vector.co.nz/blob/vector/media/vector-regulatory-disclosures/annex-3-whole-system-costs-in-nz.pdf

74. **We recommend that the Commission considers the impact on the consumers overall "energy wallet" when considering network price increases.**

Consumer impact model

75. Vector has a few recommendations to help improve the consumer bill impact model that was used for the DPP3 reset.

    a. The Commission must provide documentation to follow the model interlinks and sources;

    b. The provenance of the MBIE figures on c/kWh is unclear. For e.g. was this an outside calculation from EDBs' Schedule 8. There needs to be evidence that only residential tariffs are picked up for this purpose;

    c. The Commission also needs to be careful with recent changes to Vector's Transmission pricing[14] for that component of the calculation;

    d. The DPP3 model was based on 22kWh per day on the cheapest low user tariff available without a fixed term contract i.e. not a conservative approach and with the low user fixed charge being phased, this is no longer appropriate;

    e. Vector believes that instead a sensitivity analysis would be more appropriate – i.e. an average bill impact with a given range;

    f. For the model to provide more informative information for stakeholders the Commission could look at including levels of consumption to provide a range of impact; and

    g. Another input that could prove valuable would be average census data for household income; the model could use regional income date by mesh block to inform bill impact by income level to truly highlight affordability issues.

76. Below is an example of the type of output that could be produced: a table of bill impact burden by usage and income:

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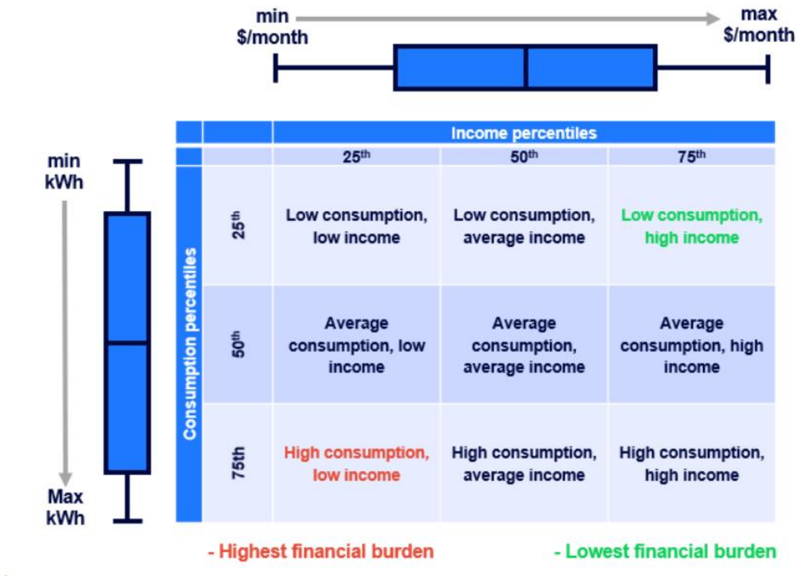
[14] See page 16 of Vector 2024 pricing methodology here: https://blob-static.vector.co.nz/blob/vector/media/vector-2023/electricity-pricing-methodology-2024.pdf



77. We would be happy to discuss these recommendations further with the Commission to understand how this output could be achieved.

Consumer engagement

78. The Commission has asked specifically what engagement have EDBs had with consumers and iwi about resilience expectations, especially as it relates to significant step changes in forecast expenditure. We have summarised our interactions and outputs below.

a. Businesses and Stakeholder Group Engagement

Business/ stakeholder	**Method of engagement**
Auckland Business Improvement Districts	5 x 1-2-1 discussions, 1 x survey
EMA	1-2-1 discussion
MEUG	1-2-1 discussion
Data Centres	1-2-1 discussion
Auckland Council	1-2-1 discussion
Auckland Transport	Survey
Auckland Airport	1-2-1 discussion
Waste Management	Survey
Kiwirail	Survey
Watercare	Survey

b. Residential consumer engagement:

- We surveyed customers after Cyclone Dovi to understand outage tolerance during normal weather and major weather events;

- We ran community hall engagements – see case study 2 for details;

- We asked customers experiencing electricity faults how satisfied they were with their outage duration & collected unprompted feedback that mentions resilience or outage duration as part of our ongoing voice of customer programme; and

- We asked residential customers about how important outage duration is to them and how they rate Vector's performance in this area via our engagement surveys run ahead of the DPP3 reset.

c. Third-party research and publications from across New Zealand, Australia and the United Kingdom.

79. What we have learned is that resilience is the second most important energy factor for New Zealand residential customers behind affordability, while New Zealand businesses rate it on par or above affordability as their activity depends on having a reliable and resilient energy supply. Resilience has increased in importance for all segments in New Zealand after the early 2023 major storms and floods, but levels of trust about the New Zealand energy market delivering a resilient system in the future are low. Affordability is top of mind for customers when it comes to energy, but this needs to be achieved in conjunction with providing a reliable and resilient energy supply while meeting decarbonisation goals.

80. Meanwhile, United Kingdom and Australian customers state they want to have a say in resilience investments to manage costs and climate risks.

81. Vector intends to outline in more detail the findings of our consumer, iwi, and stakeholder engagements in our 2024 AMP.

82. While we acknowledge the importance of consumer and iwi engagement in the regulatory process, the Commission must ensure that it recognises that engagement is not costless to EDBs. **We recommend that the Commission considers consumer, iwi and stakeholder engagement expenditure as a component of an opex step change in the setting of EDBs' opex allowances (see section on 'step change requests' later in this submission).**

Case study 2: Community hall engagement
Over the past few months, members of our customer excellence team, electricity operations control room, and marketing and communications team have been out and about explaining the work we do to improve electricity resilience and reliability in some of our trickier areas.

These community meetings have been well received, and we are building some great relationships along the way. They are not just a chance for our customers to hear from us, we get to listen to our customers too, relentlessly pursuing a better understanding of who our customers are.

Warkworth

Warkworth, north of Auckland, is an area that is growing quickly, while still having many rural communities served by a largely rural network. We have spoken to several local community groups in the area about all the investment we're doing to get ready for growth and electrification, as well as improve reliability in those rural areas.

Over the past five years we've invested more than $60m into the area, and, as we face the challenges of decarbonisation and climate change, the requirement for investment will continue. Here are some of the projects we spoke about:

We are in the final stages of laying a new underground cable, all the way from Wellsford to Warkworth, to boost capacity for the future, and increase reliability. This has been a large capital project with $50 million invested over four years.

We have built a new substation at Big Omaha, so power supply is more evenly spread and fewer customers are attached to an individual line meaning that if an outage happens, not as many people will be affected as in the past.

Battery energy storage systems in Snells Beach and Warkworth South are being used to make sure power supply matches demand.

Henderson Valley

Henderson Valley is another rural community, supplied by lines that run to Piha, through the Waitakere Ranges. As the bush there matures, it presents more challenges for keeping the power lines clear of trees, especially in windy weather.

We spoke to the Henderson Valley Residents Association to explain our work with Auckland Council on resource consents to manage the trees. We want to have a safe clearance between trees and our power lines, and we heard from residents about some of the challenges they face when their community is cut off during extreme weather events.

While there is no magic bullet for preventing power outages in this area, we were able to share more information about how we prioritise network repairs in storms, so that the community is better informed for next time.

The Capex framework rightfully needs to be reviewed

Approach to capex allowance setting

83. The Commission is right to review its approach to capex allowance setting for this reset. The nature of the building blocks approach to the establishment of revenue allowances and the principle of FCM means that the price impact of capex in any one year is a fraction of the spend in that year. This is important for the Commission to bear in mind when considering forward-looking capex allowances.

84. The risks and consequences of under-investment by EDBs resulting in slower decarbonisation and less resilience in their networks in the face of extreme weather events are far more than the risk and consequence of small price increases spread over the life of the infrastructure funded by EDBs to meet these needs.

85. The Commission has correctly picked up in its ‘environmental scan’ phase the drivers for the increased capex forecast requirements.

86. As we mentioned earlier, Vector welcomes the independent review being done by IAENGG to ‘assess’ EDBs’ forecasts despite some concerns that how IAENGG will determine “good industry practice” has not been defined. We agree that EDBs’ AMPs are the best place to ‘assess’ capex forecasts in a low-cost regulatory regime such as a DPP.

87. The phase we are most concerned about in the steps for setting capex forecasts, is the ‘design’ and ‘adjust’ phases. The Commission intends to engage with EDBs via a workshop and a potential further s53ZD request in early 2024. In our view the ‘design’ step should come earlier, so that there is clear guidance on the levels of supporting information required to identify ‘supported expenditure’ categories. This would ensure that EDBs can provide the justifications within their 2024 AMP disclosures.

88. That said, we welcome the Commission not being wedded to arbitrary caps such as the aggregate expenditure cap of 120% of historical spend applied in DPP3 and which have at times served to constrain the level of investment forecasted as needed to address Auckland’s decade of growth. The ‘adjust’ phase must be looked at on a capex category basis. We look forward to participating in the design framework workshop in early 2024.

89. Finally, we note the potential for a further s53ZD request for supporting information for capex forecasts in early 2024. We would like to understand more details around the nature of this request, how it will be used, and for it to be provided as early as practicable so that guidance is available to resources who will also be completing the 2024 AMP disclosure during this period. The Commission should appreciate that such requests impose significant extra workload on the requested businesses and should not be undertaken lightly (particularly where the annual process of AMP24 is so imminent).

90. **We recommend that the Commission provide previews of their emerging views at least a week ahead of the capex framework workshop.** This will ensure that EDBs can properly engage on the proposals for the ‘design’ and ‘adjust’ phases and ascertain what the emerging views means for their own circumstances.

Resilience expenditure in our S53ZD submission

91. The 2023 Auckland floods and Cyclone Gabrielle were extreme events which prompted a review of future resilience expenditure for the electricity network. Despite identifying increased investment required over DPP4, we have not included this proposed expenditure in our section s53ZD information request response. Whilst it is important to provide such an indication to the Commission, there are several reasons why Vector has elected to separately identify, but not include, such expenditure, including:

    a. Fundamental concerns and uncertainty around the financing of future investment based on Commission precedent of limiting price increases that would have the effect of any additional expenditure not providing any additional revenue for circa 14 years.

    b. The previous Government undertook a significant review of infrastructure resilience generally and we await any findings, conclusions or recommendations of that review.

    c. There is potential reform to Tree Regulations which are fundamentally not fit for purpose. Any changes to the Tree Regulations would have spending implications for resilience given that, for example, over 60% of Cyclone Gabrielle outages were vegetation related.

    d. The previous Government floated the possibility of Government funding of infrastructure resilience expenditure and while no specifics were identified, this is an option open to Government to support resilience expenditure outside of impacts on electricity consumer bills.

    e. Given uncertainty, Vector does also not believe it right to include and, by implication, have customers start to fund, resilience expenditure which could be subject to material change from movement in Government policy in particular. We acknowledge, that largely due to interest rate and inflation adjustments in the WACC that customers already face a significant inter- period (P0) adjustment and by adding further proposed resilience expenditure into our forecasts would translate to additional costs for customers.

    f. Our assumption is that were greater clarity to eventuate throughout DPP4 that the Commission would accommodate a re-opener for such additional resilience expenditure. We will work with the Commission prior to submission of AMP24 to confirm our understanding of the reopener process for further resilience expenditure. Our concern is that the Commission has recently rejected the possibility of EDBs being eligible for re-openers on the basis of Government policy changes. Were Government policy to target levels of resilience greater than today, we are keen to understand from the Commission how this could be accommodated by the re-opener process.

Resilience and uncertainty

92. The IM review final decision to include expenditure related to resilience within the scope of the unforeseen and foreseen major capex reopeners is a positive one. But reopeners should not

be the only solution available to resource resilience investment, in particular if it is reactive to an extreme event.

93. Reopeners take time to interpret (often requiring legal advice on both sides), they take time to apply for, and they take time to assess and if successful take time to implement through pricing.

94. Transpower are looking to circumvent the above through their regulatory control period 4 (RCP4) proposal[15] by requesting a use-it-or-lose-it (UIOLI) allowance[16] for resilience expenditure. The UIOLI mechanism is not part of Transpower's individual price-path (IPP) regime, yet they have applied for it and have the support of their independent verifier to do so.

95. EDBs should have access to the same type of mechanism, if Transpower's proposal is accepted by the Commission. The regulatory burden imposed by a UIOLI scheme would be no more involved than that of a reopener, and yet funds would be accessible immediately. Indeed, for resilience the preference would be access to these funds ex-ante (UIOLI) and not ex-post (reopener).

96. **If the Commission is mindful to introduce a UIOLI fund for resilience for Transpower it must also reconsider its IM final decision to not allow such schemes in the DPP.**

97. Another idea Vector proposed during the IM review consultation[17] was for the Commission to consider pass through costs for storm response to ensure EDBs are being funded efficiently to respond to severe weather events. There would be no need to apply for funding (via the catastrophic event reopener) and confidence in efficient 'passed through' expenditure would be audited through the annual Electricity Price-Quality Compliance Statement. EDBs can invest in the best interest of consumers without having to apply for ex-post funding which is uncertain, slow, open to legal interpretation and the Commission's discretion.

98. We note that the IM review final decision has not entertained this idea, but we would urge the Commission to look at the UK where there is precedent for such a scheme. In RIIO-ED2, Ofgem made Severe Weather 1-20 costs a pass-through item. Previously in RIIO-ED1, network companies had specific allowances specifically for these events but due to the difficulty in forecasting their frequency and impact, they changed it to pass-through.

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[15] Transpower RCP4 proposal, November 2023, https://static.transpower.co.nz/public/2023-11/RCP4%20Main%20Proposal%202023.pdf?VersionId=TRqSogShhDfomL4gVwFzlzzzGSfRjz30

[16] The uncertainty mechanism proposed in RCP4 for resilience is a 'use-it-or-lose-it' discrete funding mechanism. If it is not spent, then funds are not recovered from consumers, and Transpower would not receive an incentive payment for underspending. Although an uncertainty mechanism comes with an additional regulatory burden, it means consumers face less risk on the uncertainty of the need and the cost compared with including the funding requirement in base capex/opex.

[17] https://blob-static.vector.co.nz/blob/vector/media/vector-regulatory-disclosures/vector-submission-2023-in-period-adjustments.pdf

99. We also note the importance of network spares and holding inventory of key assets in order to respond to severe weather events. The regime needs to ensure these holding costs are compensated for in EDBs' capex allowances in particular when there are global supply chain issues, and which could result in kit replacement availability when storms affect large parts of the country. Currently the regulatory regime does not compensate for the holding of significant spares (noting the historic Wellington Electricity CPP) and a question exists whether the Commission, in the context of the predicted increase in severe weather events, combined with global supply chain challenges, should re-examine its treatment of holding strategic spares.

Electric vehicle system growth capex

100. The last two years have seen an acceleration in EV uptake in Auckland. Should such growth continue, there is the potential for this growth to impact on our upstream assets.

101. However, with the imminent removal of the Clean Car Feebate scheme, it has become extremely difficult to forecast future EV uptake with levels of confidence appropriate for including identified network reinforcement capital costs.

102. As such, Vector has identified, but elected not to include within our s53ZD response forecast capex expenditures, for system growth expenditure triggered by the current EV uptake forecast trends on the grounds that:

a. EV uptake numbers could materially adjust following the removal of the Clean Car Feebate scheme and there is little ability to model this short of observing any changes to demand in 2024.

b. Consumer choice, range anxiety, the availability of new models of vehicles, changing prices each impact the uncertainty around the modelling and subsequent forecasting of EV uptake.

c. The uncertainty of the Commission's application of any potential financeability test and/or constraining cashflow funding between the DPP3 and DPP4 regulatory periods mean a conservative approach should be applied to any additional expenditure – given that where funding is constrained any return on additional capital expenditure is not observed for many years.

d. The decision to identify, but not include, is also reinforced by challenges of customer price impact of DPP4 price changes and where it would be inappropriate for customers to be funding capital expenditure for which an element of uncertainty exists.

e. We await the proposed Government initiatives around smart home EV charging which, once adopted as the UK already has, could provide greater confidence of smart and scheduled management of EV load (similar to the UK's policy) which could mitigate or avoid potential peak load from EV charging in the home. A significant proportion of future network load is driven by EV uptake and Vector continues to advocate strongly for smart and coordinated EV managed charging as a means to meaningfully reduce the required capital expenditure and network reinforcement costs.

f. Like resilience, our assumption is that were EV growth to continue on its current trajectory (despite removal of the Clean Car Rebate) that the Commission would be open and incentivised to address such a scenario swiftly through a reopener. While some uncertainty exists as to whether broad load growth such as EV growth by individual customers (as distinct from large non-forecast point loads) is captured by the Commission's proposed re-opener categories, Vector intends to work with the Commission to confirm the availability of a reopener prior to submission of AMP24.

g. We also note that the area of EV growth could also be a prime candidate for an even simpler "*updater*" or "*difference to stated assumptions*" process whereby allowances could better reflect actual out-turn data where this is materially different to the stated forecast numbers used for the DPP reset. For example, without the need to apply for a re-opener, EDBs could demonstrate and therefore unlock greater allowances, if auditable and verifiable input numbers were materially different to forecast and assumed input numbers for an EDBs reset allowances. EV growth is a prime candidate for such a new, simpler process given the uncertainty of EV uptake scenarios and changing policy settings. Such a process could also drive better consumer outcomes given it would avoid the need for EDBs to conservatively seek capital investment for EV uptake which consumers fund ahead of observed actual uptake.

Deliverability

103. Our overriding position on deliverability is that it is outside of the Commission's mandate. The Commission needs to provide the regulatory settings to incentivise investment which includes financeability but that does not extend to deliverability. Suppliers are the best placed to make decisions on the "how" and whether investment can be delivered as forecasted. The Commission do not work or operate our businesses and are therefore not well suited to make judgements on whether certain investments are deliverable or not. Direct operational control of suppliers would in our view be very out of step with the Part 4 purpose.

104. That said, Vector has a strong track record of delivering through periods of significant growth. We have witnessed Auckland grow extensively, and ahead of the Commission's forecasts, over the past decade with no signs of easing.

105. Our number of new connections in a year has grown by 40% compared to five years ago; distribution transformer capacity (EDB owned) has increased by 13% since 2018; and our network length by 4% for the same period[18].

106. This has led Vector to invest and deliver in an efficient manner even during a period where we have witnessed external factors heighten deliverability issues (such as high inflation, Covid-19 on supply chain costs and access to goods and materials).

107. However, there is always a concern that other global events could emerge, infrastructure build across all sectors seems in very high demand, and that inflation remains high in DPP4. These external factors, coupled with increased capex investment will mean that allowances need to reflect these trends, making the 'design' phase of capex allowance setting even more critical. To mitigate these concerns, Vector actively engages with our delivery partners around our forecast investments and future resourcing requirements.

108. The Commission considers deliverability of significantly increased work programmes may be challenging given current labour market conditions and wider supply chain issues. According to them, the price impact of these issues is to a certain degree reflected in the current historical high rate of increase in the capital good price index (CGPI). Vector has not in the time available been able to explore this in detail but will consider it further in our cross-submission.

Anticipatory investment

109. The Commission has asked for information on investment decisions being considered due to concerns on delivering increased scale of investment in limited time which are not consistent with a least-cost lifecycle basis assessment. In other words, the Commission would like to ascertain whether EDBs are investing in advance of forecast need or for demand or generation that are only speculative.

110. Vector adopts a 'just in time' investment approach. Case study 3 below, is an extract from our 2023 AMP describing how our planning, processes and people come together to ensure we co-ordinate where possible projects that can be delivered together for an efficient outcome.

111. We also co-ordinate with key stakeholders such as Transpower, Auckland Transport and Auckland Council, to ensure we combine delivery of programmes of work not just internally but also with other players on our network's patch.

112. While this approach has worked through a period of extensive Auckland growth, we are mindful that electrification of transport and the potential transition away from fossil gas heating

[18] All figures derived by comparing our RY2023 EID to the RY2018 EID available on our website here https://www.vector.co.nz/about-us/regulatory/disclosures-electricity/financial-and-network-information

may warrant a change of 'pace of delivery, pace of change and pace of build, over perfection[19] as it is clear that the consequences of underinvestment outweigh the risks and impacts of EDB overinvestment.

113. Finally, Vector's capital contributions policy to charge the upfront investment of new connections to the connecting party upholds a risk adverse investment approach and avoids over or under investments in connections and system growth. Such an approach ensures that over 50% of our gross investment is "customer activated" and in response to direct demand from customers. For Vector, we assume this considerably mitigates the Commission's concerns over speculative investment.

Case study 3: Investment 'just in time' [20]
The forecast peak winter demand within the 2023-2033 AMP period is expected to increase by roughly 1000MW from 1800MW today. This highlights the importance of the next decade of having the right plans, processes, and people to succeed. In terms of transport electrification, this AMP demand forecast includes the adoption of light-duty EVs in line with government targets and the electrification of buses and Ferry fleet in line with Auckland Transport (AT) plans. To effectively manage investment planning, the network has been divided into geographical planning areas, which correspond to existing individual GXPs or group of GXPs. From the top down each subtransmission and ZSS supplied from the respective GXP is covered under the corresponding planning area. Where a new GXP is forecast to be needed in the future, then this is included in the planning area based on today's view. Each Network Planning Area summary describes the physical bounds of the area, the GXP, the ZSSs supplied from the GXP, demand forecast, and network development projects. In developing the projects, Vector considers any asset replacements or other investment that is planned for other drivers (such as condition) to ensure a coordinated and efficient approach to expenditure. Within each planning area, Vector works with Transpower to ensure that demand at each GXP is managed efficiently to avoid over-expenditure on the transmission network when the constraint can be addressed at the distribution network level.

[19] Words used by Jonathan Brearley in his speech to the Infrastructure Network Investor Forum on 13 September 2023, available here https://www.ofgem.gov.uk/publications/jonathan-brearleys-speech-infrastructure-investor-network-investor-forum

[20] Vector 2023-2033 AMP p.96, available here https://www.vector.co.nz/about-us/regulatory/disclosures-electricity/asset-management-plan

To ensure efficient expenditure, the need for augmentation of any zone substation is assessed with consideration of the support that can be provided from adjacent zone substations. In many cases, multiple zone substations supply an area, so the ability to transfer load between substations to avoid significant expenditure is considered.

The Opex framework remains stuck in the past

Base step trend approach

114. The Commission has proposed to maintain its 'base step trend' approach to opex forecasting. While this worked in the past, we believe there is scope to consider EDBs' AMP forecasts of certain opex categories where the drivers are known, better understood and are changing in response to either technology, wider mega or societal trends (such as social, and corporate governance (ESG) reporting, complexity associated with developing distribution system operator (DSO) capability, iwi and customer engagement, cyber-attacks), or more broadly the demands of electrification. For example, we would suggest non-network opex would be better suited outside of a trend mechanism.

115. Non-network opex needs to align with capex forecasts and consider the growing regulatory, legal and policy changes EDBs will continue to face through DPP4. The Commission has requested in its Issues Paper the levels of consumer engagement EDBs have undertaken in relation to resilience. Consumer, iwi, and stakeholder engagement also bear a cost to suppliers. Both the Commission and the Authority have both indicated they would like to see more done in the future, whether that is to inform the reset process (Commission) or in respect of distribution pricing (Authority).

116. AMPs and EIDs are growing in requirements and complexity through the targeted information disclosure review (TIDR). Through the DPP reset process we are witnessing how crucially important these disclosures are in the setting of EDBs' revenues. During DPP4 we will reset DPP5 and witness the start of the next IM review. To challenge regulators, these once every five- and seven-year 'price controls', require expert advice from a range of consultancies.

117. In the policy sphere we are waiting for the outcomes of key MBIE workstreams: The National Energy Strategy, the Gas Transition Plan, and the ongoing review of Tree regulations. These policy changes are not covered by reopeners, this was a decision made in the IM review. So, while EDBs resource and plan for these changes, the Commission would not reopen the price path for any additional expenditure occurred until these policy changes were established into law. The Commission can either anticipate this meaningful reform or pretend it does not exist.

118. These are not uncertain events in DPP4, they will happen and EDBs will need to be appropriately resourced to respond. For that reason, EDBs are best placed to forecast the resources and systems needed to cater for these upcoming changes rather than underlying trend factors.

119. Vector welcomes that the Commission's approach to using capex as a driver for non-network opex, but it must go further and start using EDBs' non-network opex forecasts instead of a base step trend approach.

Step changes

120. None of the twenty opex step changes requested by stakeholders at the DPP3 reset were accepted by the Commission[21]. The Commission, in a changing world, needs to approach this with a much more open mind, otherwise it remains simply cemented in the past, acting as "regulatory drag" on the energy transition. This is an important area which we believe the Commission needs to explore and approach in a different way than it did in 2019. We are keen to work with the Commission to understand how categories such as smart meter data costs and cyber security services were rejected in 2019 by the Commission - even in the face of very strong context and commentary around how important smart meter data was becoming for networks and the risk of cyberattacks were increasing. As a sector in significant transformation, Vector believes there must be a better way for the Commission to consider and support step-changes in expenditure and that to do so is vitally important for DPP4.

121. There are several things to consider around the opex step change process:

a. Guidance: there is no defined way or guidance for EDBs to apply for an opex step change. At what stage of the DPP reset process do EDBs apply? Should these step changes be part of our 2024 AMP disclosure or could they be done via a separate submission to the Commission (via a pre-defined template for example).

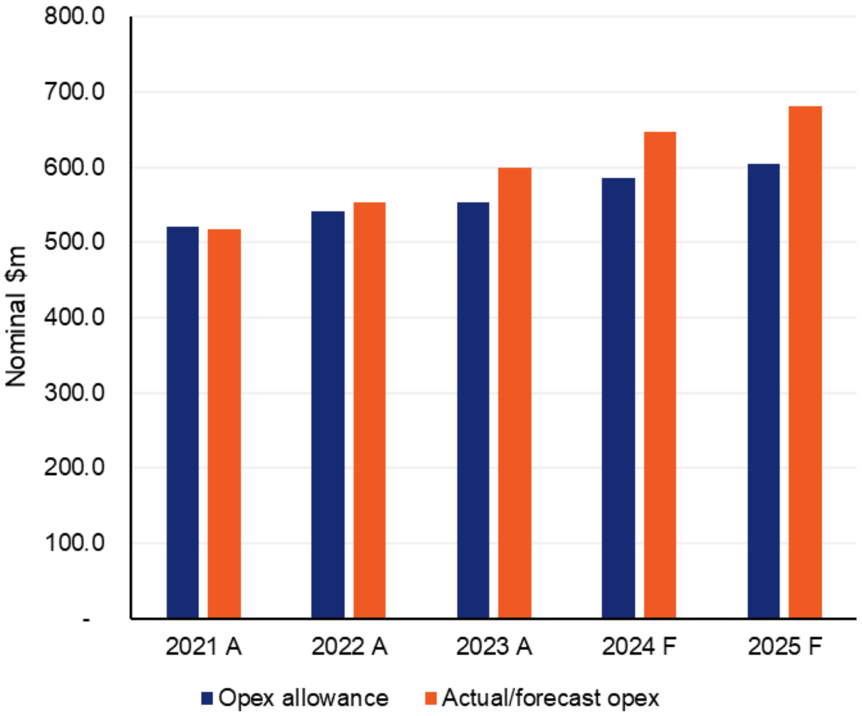
b. Criteria: The Commission has expanded on its criteria for step changes used for DPP3, a positive move given how vague they were for the last reset. As noted above none of the DPP3 step change requests made by stakeholders were accepted by the Commission. This included some crucial forecasts related to LV network monitoring, cyber security, data costs, health and safety, and new technology. The step change criteria were near impossible to meet then, we are not sure what has changed to make it easier for EDBs now. If the process was further clarified this would be a step in the right direction, as per our point on 'guidance' above.

c. Step changes vs IRIS: Most EDBs have incurred costs related to disallowed step changes in opex for DPP3, with some, including Vector, facing IRIS penalties for having overspent the insufficient allowances. Graph 2 below displays how non-exempt EDBs overspent their opex allowances through DPP3 (2% in year 2, 8% in year 3, and forecast to overspend by 10% in year 4 and 13% in year 5). It is not satisfactory that EDBs must

21 Paragraph A59 from the DPP3 Reasons Paper available here: https://comcom.govt.nz/regulated-industries/input-methodologies/input-methodologies-for-electricity-gas-and-airports/input-methodologies-projects/2023-input-methodologies-review?target=documents

overspend within a DPP and incur only partial recovery of those costs in order to have them in the base year so that they are funded for the next DPP. Furthermore, the Commission assumption that the base year is the best predictor of future opex spend will not always hold true. For example, an EDB may be paying for meter data that is only consumption data in the base year but have been working with MEPs to receive network operation data in the next DPP. The opex cost for the network operational data will not be reflected in the base year.

Graph 2: Total opex actuals/ forecast compared to opex allowances



d. Capex bias: the effect of step change criteria being a huge hurdle to meet could have unintended consequences. Under case study 4 if opex forecasts related to DSO and/ or flexibility services were not granted as a step change for DPP4, this could disincentivise an EDB to adopt a non-wire alternative solutions and instead invest in a more traditional capex solution and avoid an IRIS penalty.

e. Reopeners and customised price-paths (CPP) vs step changes: we do not believe that the levels of expenditure in consideration for opex step changes would necessarily qualify for either a reopener or a CPP.

f. Innovation project allowance (IPA) vs step change: similarly, only a very small subset of step changes would qualify for the IPA or innovation and non-traditional solutions allowance (INTSA) under the latest IMs. The expenditure is also limited and the EDB bears 50% of the risk on its investment.

122. One of the criteria that we disagree with is that a step change needs to be applicable to most (if not all) EDBs. Even though the Commission has demonstrated a degree of leniency in

its Issues Paper, it is important it appears that EDBs collaborate on opex step changes. Whilst Vector is actively liaising with the ENA on how best to support a joint application of step changes in order to meet that last requirement, step changes will only really fit the lowest common denominator if all EDBs need to be on board. This also raises the question that certain EDBs may be more advanced than others in certain activities (for e.g. transition towards DSO functions), does the Commission really want to hold those EDBs back? Also, the Part 4 purpose talks to outcomes in a workably competitive market. Assuming all participants would be facing the same step changes in opex is not consistent with a workably competitive market.

123. We recommend that the Commission provides significantly greater clarity on the process for opex step change requests, including:

a. When and how do EDBs apply for an opex step change; and

b. How should EDBs deal with step changes that are hard to 'robustly verify' and do not meet the criteria for a reopener, CPP or IPA/ INTSA application.

New costs

124. One of the major issues we see with the base step trend approach is that it excludes new costs i.e. costs that will not have been incurred in the base year but will be spent in DPP4. The criteria 'robustly verifiable' becomes extremely hard to quantify for these future expenditure areas.

125. A perfect example of future costs is described in case study 4 below on flexibility services. There are clear opportunities for EDBs to maximise the orchestration of distributed energy resources (DER) to avoid network constraints and minimise costs to consumers by delaying network investment. To enable these functions for networks, EDBs will need to expand their capabilities. Unfortunately, we do not believe that forecasting costs is possible to the degree that will 'robustly verify' them to the Commission and that the piecemeal nature of these types of expenditure would not lend themselves to reopeners.

Case study 4: Flexibility services
The fundamental assumptions underpinning the design of electricity distribution systems are being challenged due to the increasing availability of affordable consumer devices that dynamically manage electricity use and generation across electricity distribution networks. This concept is referred to as demand flexibility and is gaining traction in energy markets worldwide. New Zealand is no exception and Vector has been involved in the formation of the FlexForum in 2023, a New Zealand industry association focussed on practical steps to maximise the value of flexibility in Aotearoa. Vector also plays a leading role in Electricity Networks' Aotearoa's Future Networks Forum. Distributed energy resources (DER) such as battery storage, solar photovoltaics and electric vehicles can inject power on to local electricity distribution networks. Similarly, DER such as heat pumps, electric vehicle chargers, and hot water cylinders can now synchronise their consumption in response

to various signals such as periods with low prices or emissions – an effect sometimes called ‘herding’. If either generation or synchronised consumption are sufficiently large or concentrated, these DER can affect the power quality for neighbouring consumers, trigger safety settings or damage network equipment if the DER are not able to be operated within the physical limits of the network. Over time, the changes in network flows will likely precipitate network upgrades.

While DER and herding can challenge the physical limits of electricity distribution networks, there is an opportunity to increase interaction between electricity distribution networks and consumers (and their DER) so that the physical network infrastructure can accommodate this transition efficiently and effectively.

To realise this opportunity, networks will need access to resources allowing them to adapt design and planning practices, expand on existing network operational capabilities, and increase engagement with consumers and 3rd parties managing consumer devices.

New Zealand’s experience with residential hot water load control and load management arrangements with large industrial and commercial customers serves as a foundation to manage additional complexity from growth in DERs and herding, but we also must learn from markets, like the UK, that have begun implementing new solutions.

The concept of a distribution system operator (DSO), which has responsibility for signalling and coordinating flexible resources on the distribution network, has advanced in the UK to the point that the Electricity Networks Association (ENA) has defined the activities that a DSO will undertake and Ofgem has created a regulatory environment to fund, deliver, and monitor those activities. The 46 activities that ENA UK have identified are grouped into three main roles (# of activities): Role 1: Planning and network development (15), Role 2: Network Operation (15), and Role 3: Market Development (16).

There are different levels of maturity within each of the three roles that must match DER adoption rates, capabilities, interactions with markets, and consumer expectations. Uncertainties around supply chain constraints, future economic conditions, consumer sentiment, among other factors will affect the timing of investments to deliver on future DSO capabilities. We have reviewed the ENA UK framework and see strong parallels with the work we have started and expect to do more as DER adoption becomes more commonplace and eventually reaches scale in New Zealand.

As DER scales up in New Zealand, networks will need to match that growth by adapting existing activities and undertaking new activities to continue to deliver electricity distribution services effectively and efficiently. Developing estimates for the timing and costs of implementing these changes to planning, building, and operating networks is dependent on many factors, many of which fall outside of our control – including the rate at which consumers take up new technology and flexibility traders begin to aggregate and participate in the wholesale market. These levels of uncertainty have created an urgency within networks to plan and learn ahead of the need to be prepared if estimates of future DER growth are wrong, and this creates a natural conflict within our existing regulatory framework.

126. The Commission must not miss the huge opportunity to enable flexibility markets. It simply needs to look at what the Authority is already doing in this space where they recently:

a. Made Code changes to enable fleets of distributed batteries to offer instantaneous reserves;

b. Made Code changes (RTP and Dispatch Notification) to:

- provide more price certainty for parties choosing to aggregate DER and respond to spot prices
- enable aggregators to offer tranches of dispatchable load into the wholesale market, for explicit dispatch by the system operator; and

c. Encouraged EDBs to shift to time-varying distribution pricing, which further encourages aggregator activity.

127. **We recommend that the Commission considers a targeted innovation fund for EDBs to access expenditure related to flexibility services and/or when that payment is to a particular flexibility provider the Commission should consider this as a pass-through cost.** We do not consider that the IPA or INTSA would accommodate these funds in a timely manner. Instead, the expenditures would need to be qualified as related to flexibility services or paid to a flexibility provider by an auditor through the annual information disclosure process.

128. There could be a high volume of requests for flexibility payments as EDBs grow their ability to use flexibility as a demand management response.

129. Unlike other innovation projects, innovation allowances for flexibility service payments could be standardised. Payment budgets could be based on a common calculation method providing the opportunity to standardise the application process.

130. We recommend applying a streamlined version of the current IPA which allows an EDB to recover flexibility payments as a recoverable cost applied as part of the Annual Compliance Statement:

a. Ex-post application to recover costs part of the annual Compliance Statement process;

b. Standardised calculation, template for each application on an allowance with transactional evidence of payments;

c. Verification of evidence by auditors; and

d. Maximum limits applied to each network.

131. There are a number of advantages of such a scheme including regulatory certainty by providing EDBs with confidence to procure non-wire services, and it being a light touch and low

cost solution to boost innovation in this area, with no additional verification resource from the Commission required.

132. In addition, a definition for what qualifies as ‘flexibility’ for the IMs has already been worked up by the FlexForum in the glossary of their flexibility plan[22] which has representatives from all sectors.

133. While we foresee some pushback around auditing costs and potential for price volatility year on year through the annual recovery of costs, we believe these can be mitigated by proposing templates for calculations and placing an annual limit on recoveries.

134. While the Commission may state that flexibility services might increase overall opex expenditure the efficiency gains made on capex expenditure will reward EDBs through the IRIS mechanism. We would argue however that this is new territory and the market is untested therefore should not rely solely on IRIS incentivising the efficiency gains.

135. Meanwhile, EDBs are soon to be required to report on their investigations into non-traditional solutions in the AMPs, so the Commission will be able to keep track of progress made if a new mechanism was introduced.

136. The energy transition requires fast-moving, flexible regulatory funding mechanisms in order “to enable flexible DER to provide services to national markets in a way that keeps distribution networks safe and stable, and maintain power quality to consumers within legislated limits, distributors will need to provide operators of flexible DER with network access that represents not just maximum physical operating limits, but possibly also physical limits on the rate-of-increase of demand or output that the network can handle to avoid creating unmanageable surges (which could happen if the wholesale price, or the system frequency, suddenly drops or increases). With more DER operating, distribution networks will increasingly need to be operated similarly to the transmission network”[23].

Insurance costs

137. The Commission is considering alternative ways to forecast insurance costs outside of the standard trend approach. This must be the case because insurance premiums are increasing at a greater rate the base trend approach will allow. It is important that the Commission recognise the benefit consumers get from suppliers procuring efficient levels of insurance. Any underfunding of insurance is likely to lead to a reduced level of insurance cover. Insurance proceeds reduce the cost of rebuilding post an event and therefore reduced cover would likely translate to reduced insurance proceeds and greater rebuild costs. Costs that in the end of the day would be borne by consumers.

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[22] https://www.araake.co.nz/assets/Uploads/FlexForum-Flexibility-Plan-1.0-31-August-2022.pdf

[23] Quoted from the FlexForum Insights report, 31 January 2023, available here Microsoft Word - FlexForum Document.docx (araake.co.nz)

138. We note the following that challenging insurance market conditions continue both here in Aotearoa and globally (conveyed to us by Marsh[24]):

a. New Zealand property insurance buyers should anticipate further premium increases and capacity challenges through the second half of 2023, as market conditions remain firm.

b. A key driver of market conditions is New Zealand's recent extreme weather events experienced in early 2023. Together, losses from Auckland's January floods and Cyclone Gabrielle are currently estimated to total $5.01bn, making this the largest non-earthquake event New Zealand has experienced.

c. Globally, 2022 was one of the costliest years on record for insured natural disasters according to Swiss Re, with events such as Hurricane Ian in the US and floods in Australia and Asia contributing. Swiss Re also note that natural catastrophes totalled $50bn in the first half of 2023, above the 10-year average.

d. Faced with the rising cost of natural catastrophe events, reinsurance pricing has increased, and reinsurance capacity has reduced. Insurers are likely to pass increasing reinsurance costs onto buyers.

e. Even prior to the Cyclone Gabrielle and the Auckland floods, significant uncertainty in the global reinsurance market resulted in 1 January reinsurance renewals with double digit increases to insurers, and high-risk natural catastrophe zones faring worse. Similar outcomes were seen through the 1 July reinsurance renewals, characterised by increased premiums and levels of retained risk.

f. Regionally, the Australian property insurance market is seeing stability begin to return after recent challenging years, diverging from the New Zealand market

g. Inflation is further impacting insurance pricing through increased property values (to which premium rates are applied), as well as escalating claims costs.

139. The Commission has stated that one way of qualifying as a step change would be to robustly verify future costs through obtaining insurance premium costs from an insurance broker.

140. We have requested quotes from multiple brokers but are told they will not provide any estimations of more than a year ahead which does not bode well for a DPP4 outlook. Without these quotes we do not believe the Commission will consider a step change once again due to the 'robustly verifiable' requirement.

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[24] Marsh, Insurance Market Commentary produced for Vector, available upon request

141. Instead we have attempted to look at the different drivers available in our information disclosures[25] to perhaps aid with a growth trend for insurance costs. Over the first three years of DPP3 Vector's insurance costs increased by 31.3%. None of the typically used drivers compare:

a. ICPs – 11.9%;

b. Transformer capacity – 6%;

c. Energy delivered – 2.6%;

d. Maximum coincident system demand – 1.7%; and

e. Circuit length – 1.7%.

142. This led us to explore other drivers which through their nature could have a bearing on insurance premiums. Neither RAB nor number of distribution substations do the growth rate of insurance costs credit:

a. Regulatory asset base (RAB) – 14.9%; and

b. Distribution substations – 8.2%.

143. And yet insurance costs will grow, in particular in areas prone to bad weather which New Zealand certainly is. We just need to turn to the flooding and cyclone events in Auckland in early 2023 for proof.

144. An Australian Energy Regulator (AER) benchmarking report for network companies from November 2022 stated that:

> "*Cyclones require a significant operational response including planning, mobilisation, fault rectification and demobilisation. DNSPs in tropical cyclonic regions may also have higher insurance premiums and/or higher non-claimable limits. Ergon Energy is the only DNSP in the NEM that we benchmark that regularly faces cyclones. Sapere-Merz estimated that Ergon Energy requires up to five per cent more opex than other DNSPs in the NEM to account for the costs of cyclones.*"[26]

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[25] https://www.vector.co.nz/about-us/regulatory/disclosures-electricity/financial-and-network-information

[26] AER annual benchmarking report, November 2022, p.52, https://www.aer.gov.au/system/files/AER%20-%202022%20Annual%20Benchmarking%20Report%20-

Data costs – a missed opportunity from DPP3

145. As a sector we must learn from the Commission's decision not to fund smart meter data costs at the DPP3 reset. This has put back the smartness of networks years and was certainly, in hindsight, not in the long-term interest of end-users. In order not to repeat equivalent mistakes, the Commission must be crystal clear on how EDBs should apply for step changes and ensures it works with the sector to ascertain what future enabling costs could be earmarked outside of the step change process. We have ascertained that flexibility services and DSO enabling costs, and insurance costs as great candidates to be pulled aside, and we welcome a wider discussion in cross-submissions and beyond on what other costs could be included on this list.

Opex step change requests

146. Despite the lack of clarity around the opex step change request process we want to signal early that Vector has determined the 'significance' of five potential step changes which we believe also meet the other four criteria set out by the Commission:

a. Network modernisation/ digitalisation including software as a service (SaaS);

b. Smart meter data: extending work carried out on our innovation project PRISMED to include network operation data, extended ICP coverage, enhanced LV monitoring;

c. Reactive maintenance in response to severe weather events to capture the increasing frequency of storms/ cyclones;

d. Insurance costs (see section above);

e. Regulatory, governmental, legal requirements on EDBs including upcoming policy changes, sustainability, consumer and iwi engagement.

147. Once the Commission's process for assessing a step change is clarified Vector will submit details to explain how these categories of expenditure meet the Commission's criteria. In any case we will do this by the end of Q1 2024 so that the Commission can consider them in its draft decision in May.

Quality standards and incentives

%20Electricity%20distribution%20network%20service%20providers%20-%20November%202022_2.pdf

148. We are satisfied that the Commission maintains its approach to quality incentives and reporting that it adopted for DPP3, including:

a. To maintain the principle of no material deterioration and set quality standards on a basis consistent with that established in DPP3;

b. To setting a 10-year reference period updated for the most relevant information and normalisation approach for major events;

c. To not introduce new additional quality of service measures; and

d. To retain revenue-linked quality incentives for both planned and unplanned SAIDI, with targets, caps, collars, incentive rate and revenue at risk set on a consistent basis with DPP3.

149. However, the Commission will be aware from our previous submissions where we shared that the aggregate SAIDI/SAIFI measures are not particularly consumer centric. The potential to reconsider quality settings more radically have not been picked up by the Commission in the DPP Issues Paper. We remain of the view that there exists considerable potential to better measure quality with a greater focus on customers. In the past we have proposed guaranteed standards and a UIOLI allowance for worst served feeders which could help meet some of these objectives.

Reliability step changes

150. We believe the Commission must apply caution to quality settings in DPP4 around:

a. The treatment of non-performance of less proven solutions;

b. Using historical data to set key components of quality targets and limits where history will be a poor predictor of the future e.g. number of major events; and

c. Where the actual current and future operating environment is or will be different from the past for e.g. fire risk as we discuss further below.

151. The Commission has rightly raised concern that the introduction of less proven solutions may create a reticence by EDBs to implement these types of solutions and result in a focus on more proven established technologies, typically, capex investments. Indeed, EDBs may not want to jeopardise their consumers losing power while they trial or test non-traditional alternatives.

152. The Commission has also mentioned issues around demand management and load shedding. As more players (aggregators, retailers, DER managers) start to take on roles to manage demand through DERs, there is a concern that herding will occur on networks which

could cause undue constraints on an EDB's network if the right market settings are not in place (for e.g. load management protocols).

153. A regulatory sandbox would help ringfence the trial of new solutions away from an EDB's quality targets and standards. The IM decision did not introduce regulatory sandboxing, but this is a clear resolution to keep innovation ongoing without the risk of damaging a supplier's SAIDI or SAIFI performance. In this case the sandbox could be geographical and ensure consumers were onboard with the trial's purpose and potential consequences.

154. We recommend that the Commission revisits its IM decision not to introduce regulatory sandboxing for this situation. Keeping the sandbox targeted in this way for a DPP will avoid complexity and keep it low-cost.

155. Meanwhile as our summers get warmer the risk of bush fires has become a grave concern for EDBs. With lessons learned from the recent fires in Maui, a viable solution to avoid the spread of bush fires is to turn off the feeders that could if left on help spread them. If an EDB had to resort to this solution the impact of SAIDI would be huge. EDBs can plan as much as possible to circumvent fire damaging the network and its surrounding trees, but a bush fire is not something to take lightly when lives are at stake.

156. The above circumstances are imminent and the if they occur will be outside control of the EDB. **We suggest this is an ideal candidate for a reliability step change by carving out or normalising SAIDI and SAIFI for any instances of shutdowns in the case of a bush fire risk management.**

Assessment of breaches

157. The Commission has not proposed changes to the annual assessment of quality standard breaches and automatic reporting if there is such a breach. The rationale for the old DPP2 '2 out of 3 rule' was to deal with false positives – that is, circumstances where a breach was reported due to circumstances outside of an EDBs control (e.g. major weather events such as the 2023 cyclone and flooding experienced in Auckland). Not removing that rule maintains the risk that false positives trigger the proposed administrative processes.

158. Based on Vector's experience, breach investigations are a material burden given the volume of information requested by investigations. The volume of material is significant ranging from structure design standards, control room processes, interruption statistics, asset condition data and security planning. Such information requests touch on all aspects of the network business and divert key resources away from running the network. This is warranted if there is a material issue to be worked through, but not if a breach was triggered by a false positive or if that breach is a continuation of circumstances that already have been investigated by the Commission and are actively being addressed through agreed remedial action.

159. The Commission has suggested that adopting higher thresholds when setting the quality standard targets will help avoid false positives. However, there does not appear to have been

any analysis undertaken showing that this is the case. **We recommend that at a minimum, the Commission considers re-adopting the '2 out of 3 rule' approach to breaches.**

Productivity metrics do not account for EDBs' growing roles

160. The Commission is running an EDB efficiency review through 2024 in order to inform the productivity factors they will use to set allowances for DPP4. Vector is deeply concerned that the Commission approach to assessing productivity in the past is no longer fit for purpose as it does not reflect the expanding roles of EDBs especially in the energy transition.

161. The drivers typically used by the Commission are network length, ICP numbers, energy delivered, ratcheted maximum demand, and system capacity. Whilst these are good indicators for the network opex categories (for e.g. vegetation management and corrective maintenance), we do not believe they paint a full picture of the increased expenditure of EDBs on non-network opex.

162. In a report sent to the Commission in December 2022 for the IM review, on behalf of the six largest EDBs, NERA outlined a table of EDBs' 'uncompensated outputs'[27]. As a collective we are exploring these further and will look to engage during the EDB efficiency review early next year.

163. At a high level these unmeasured outputs, some of which have impacted EDBs historically and for others they will grow over the course of DPP4:

a. Consents, regulation, and compliance: traffic management; health and safety; regulation, policy and compliance; resource consents;

b. New product/service: flexibility services; ESG; sustainability activities and reporting (TCFD, GHG); wider consumer and iwi engagement; and expanding customer service;

c. Digitisation & IT: general digitisation; LV visibility and monitoring; access to data and data analytics; and

d. Network resilience: insurance costs; responding to severe weather events (i.e. climate resilience).

164. The drivers used by the Commission's productivity modelling fail to adequately reflect any of the above activities which are now part and parcel of being a network distribution company.

[27] Page 9 of Innovation under the DPP: potential barriers and solutions, available here https://blob-static.vector.co.nz/blob/vector/media/vector-2023/nera-221220-innovation-under-the-dpp-potential-barriers-and-solutions.pdf

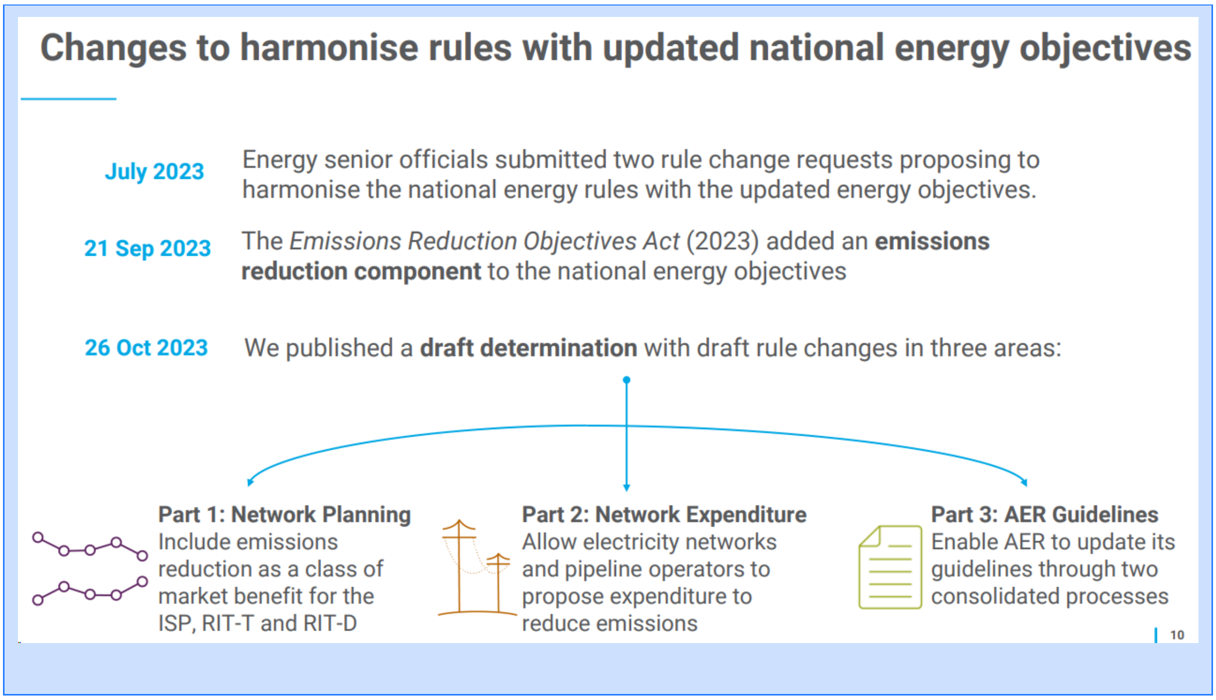
165. In its efficiency review, the Commission may be presented with graphs showing declining productivity for EDBs, however it cannot be looked at in isolation of typically used drivers, because EDBs are pulled more and more into activities which go beyond purely keeping the lights on at low cost to consumers. These atypical requirements will only grow further as move into DPP4 and DPP5. The Commission must find new ways to look at productivity which takes into account these unmeasured outputs and we look forward to engaging during the efficiency review process next year.

166. On top of this, the Commission must ensure any productivity analysis it undertakes adjusts for changes in legislation e.g. HSWA, regulation e.g. local council traffic management, accounting treatment changes e.g. SaaS.

167. The Opex modelling used in the Commission's productivity analysis must only consider opex paid for by consumers i.e. that is funded through revenues and therefore must adjust for IRIS.

Case study 5: Harmonising the rules with the updated energy objectives in Australia[28]
In November 2023, the AEMC published its draft determination on harmonising the rules with the updated energy objectives which is summarised below. The draft clearly outlines the requirements on network companies to include emissions reduction as a class of benefit but also to allow electricity networks to propose expenditure to reduce emissions.This is a positive move which was preceded by Ofgem's RIIO-2 price control efforts to also push network companies to deliver on the environmental plans to reduce emissions and increase biodiversity. EDBs in Aotearoa are not immune from national emissions reductions targets even though Part 4 does not make it a legal requirement. Vector discloses an annual TCFD and GHG emissions report, and has been very focussed on reducing emissions. Our concern going forward is that policy and/ or governmental changes during the DPP4 period could introduce more targeted requirement on EDBs reduce emissions, but no allowances would have been set (unlike in the UK and Australia), and reopeners do not account for policy changes, and this expenditure has been and will be detrimental to our productivity modelling.

[28] AEMC draft determination on 'Harmonising the rules with the updated energy objectives' public forum slides 21 November 2023



The Commission must entertain more uncertainty mechanisms

168. At the DPP3 reset, the Commission expanded their list of uncertainty mechanisms (UM), introducing additional reopeners, pass-through and recoverable costs. These were welcome additions to the suite of flexibility options for the regime. Through the IM review, the scope of reopeners has been reviewed and we welcomed the inclusion of consequential opex and resilience expenditures into the major capex reopeners. Through that consultation however, we also raised that the Commission needed to look at expanding the UMs at their disposal.

169. Reopeners are good tools, but the recovery of revenue is slow: applications take time, interpretations of drafted IMs that underpin the reopeners often need legal expertise, and the Commission needs time to adequately consider applications. There is a concern that reopeners become more frequent in DPP4 due to the uncertain nature of certain expenditure categories as the result of decarbonisation and resilience (for e.g. when will and how much investment in EV uptake will be required). The concern arises as our experience to date is that reopeners are well intended but suffer from issues when being applied for, especially for those applicants that are first to apply. We have in the past applied for accelerated depreciation, the innovation allowance, legislation reopener and catastrophic event reopener. In all these occasions we have been either the first or second to apply. In applying we have spent considerable time working on both what the application must contain and how the relevant clauses in determinations be applied. As well as engagement with the Commission in these areas and while these engagements have proved useful, they are certainly not quick at landing at an agreed position. It is therefore our view that reopeners applied for in DPP4 are likely to suffer the same plight which will result in delays in expenditures being made. These delays are likely not to be in the long-term interests of consumers. The delays and consequential costs are also likely to be a disincentive to applying for the reopener.

170. A potential solution that could speed up the reopener process the Commission should consider is to fast-track applications for suppliers who obtain independent verification.

171. We explained in our responses[29] to the IM review and repeat again here that there are other uncertainty mechanisms that the Commission could adopt to respond quickly to uncertainty in DPP4.

a. New connections volume wash-up mechanism for EDBs on DPPs and CPPs

b. A volume driver or trigger mechanism for incremental demand growth;

c. UIOLI allowance for Worst Served Feeders; and

d. Pass-through costs for Storm Response.

172. In this submission we have also included explanations why a UIOLI fund could also work for Resilience if Transpower has theirs accepted for RCP4.

An opportunity to improve innovation with the DPP

Innovation Project Allowance (IPA)

173. Frontier Economics, in their report 'Investing to enable decarbonisation and realise the benefits of electrification[30]' explains that: "…the innovation allowance mechanism hasn't encouraged EDBs to apply for innovation funding because of its time and resource intensive application process, relatively small allowance (0.1% of allowable revenue or $150,000 over the DPP3 period), and its ex-post approval structure combined with a requirement that EDBs must have already incurred an amount of costs on the innovation project that is at least equivalent to 200% of the proposed application amount."

174. Vector would like to see the Commission review the mechanism in relation to:

a. Scope: to include projects beyond the delivery of electricity lines services (ELS). Innovation schemes should be facilitating the efficient transition to decarbonise networks, but that innovation should not be limited to increased reliability (for e.g. the UK's Network

[29] Please see further details on each of these in our submission to the draft decision here: https://blob-static.vector.co.nz/blob/vector/media/vector-regulatory-disclosures/vector-submission-im-review-draft-decision-19-07-23_2.pdf; and to the in-period adjustments workshop here: https://blob-static.vector.co.nz/blob/vector/media/vector-regulatory-disclosures/vector-submission-2023-in-period-adjustments.pdf

[30] https://blob-static.vector.co.nz/blob/vector/media/vector-2023/frontier-economics-decarbonisation-and-electrification.pdf

Innovation Allowance considers decarbonisation projects and projects which facilitate the energy transition).

b. Budget: the total recoverable cost (i.e., the amount drawn down from the IPA) is limited to the greater of the 0.1% of each EDB's MAR or $150k. The NIA varies between 0.5% and 0.7% of allowable revenues. We recommend increasing the percentage to encourage larger projects. Given the IPA is intentionally small scale in nature, it may only be useful for pilots.

c. Funding: the funding mechanism is ex-post meaning that the EDB must already have incurred the costs. This is clearly a barrier so to encourage applications we recommend making the funding ex-ante.

d. Contribution: Requires a contribution from the EDB of greater or equal to the recoverable cost. Because of the ex-post nature of the IPA, the already incurred costs will be at least 200% of the proposed drawdown amount. We recommend lowering the percentage to at least 100%.

e. Recovery: The actual recovery of an approved innovation allowance is two years after the Commission's approval. The actual recoverable cost definition determines the innovation allowance becomes a recoverable cost in the assessment period it is approved by the Commission. As prices will have already been set for that assessment period, the allowance is therefore added to the wash-up account balance for that assessment period. Wash-up account balances are recovered two years after recognition. Therefore, the actual inclusion of the innovation recoverable cost is not included within prices until two years post its approval by the Commission.

Other innovation

175. NERA[31] describes the barriers to innovation for EDBs in New Zealand:

"EDBs still face the other barriers to innovation: meaning that there is no clear pathway to advance an innovation in New Zealand. To be specific, while in the first instance, the allowance reduces the initial cost to innovating, the next step of developing any project further would face the other three barriers. Overcoming these barriers would require:

- *Combining the innovation allowance with another mechanism. For example, the AER combines an allowance with a cost multiplier for implementing projects; and/or*

[31] https://blob-static.vector.co.nz/blob/vector/media/vector-2023/nera-221220-innovation-under-the-dpp-potential-barriers-and-solutions.pdf

▪ *Removing these barriers. For instance, Ofgem applies outcome incentives (and other mechanisms) so that the payoff from innovating is greater than in New Zealand".*

176. We would like to call out three of the solutions identified by NERA to overcome the barriers to innovation here in New Zealand:

a. Targeted allowance or fund: which is an allowance that can only be spent on a specific category that is difficult to measure in the allowance setting process. The purpose is to incentivise innovation in the direction of generating the uncompensated outputs/ outcomes. For precedent, Ofgem has several use-it-or-lose-it allowances for specific purposes, and now Transpower has applied for one.

b. Business plan incentives: Ofgem rewards business plans that provide value to customers; penalises firms for poorly justified costs; and rewards ambitious proposals for high-confidence costs. In theory, this set up can mitigate concerns about a capex bias because efficient costs are assessed at a totex level. In this reset there could be an assessment of AMPs which enables either the fast-tracking of EDBs' expenditure forecasts which meet the Commission's confidence levels (it sounds like the proposed 'assess' phase in the review of the capex framework might do this); and/ or a financial reward for EDBs whose AMPs present levels of ambition for the benefit of consumers.

c. Address deficiencies in opex allowances: by carving out or bespoke forecasting of specific categories. This could be addressed through the solution proposed under point a. above or as we have suggested earlier in this submission by relying on EDBs' forecasts for non-network opex, rather than the base step trend approach.

177. In its DPP3 decision, the Commission rejected Vector's request for a 'step change' to their expenditure allowances relating to LV monitoring (opex).

178. Frontier outlines that: "The DPP framework provides limited alternatives to funding activity. LV monitoring will become increasingly important as it is likely to be the first part of the network impacted by emerging technologies, such as electric vehicles or battery storage."

179. Arguably this point relates more specifically to opex expenditure. Vector has already called out in this submission that the Commission can no longer rely on historic expenditure to validate opex forecasts and that caps on capex forecasts are arbitrary. As previously mentioned, an example of opex expenditure which has risen well above its historic average in DPP3 is cyber security related expenditure, which was also rejected as an opex step change at the last reset.

Incentives for energy efficiency and demand-side response (DSR)

Section 54Q

180. Section 54Q of the Act states that in regulating electricity lines services, the Commission must promote incentives, and avoid imposing disincentives, for EDBs to invest in energy efficiency and demand-side management, and to reduce energy losses.

181. The Commission's initial view is that a specific incentive for energy efficiency and demand-side management is not required for DPP4 as the revenue cap form of control does not impede the implementation of energy efficiency and demand-side management initiatives by EDBs.

182. During the IM review consultation, Unison[32] pointed towards s 54Q explaining that:

"The Commission has not read s 54Q and s 52A consistently, nor has it demonstrated why the sections conflict such that s 54Q must be subordinated. In our opinion, the correct interpretation accepts that the regulatory mechanisms under Part 4 must both:

a) protect the s 52A outcomes (including limiting excessive profits); and

b) ensure there are no disincentives to invest in energy efficiency, demand-side solutions and reducing energy losses (as a subcomponent of s 52A(a) and (b) incentivising efficiency and innovation), as well as promote incentives in those s 54Q matters.

To meet the s 52A purpose and appropriately balance the listed outcomes, the Draft IM Decisions need to ensure there are genuine incentives to invest and resolve the disincentives to invest, in accordance with s 54Q."

183. We believe Unison's logic stands true even more so in relation to the DPP and provides yet another reason for a review of the opex base step trend approach. Investing in flexibility services is an investment towards demand-side solutions. The opex step change process disincentivises EDBs to invest in those services (in fact as explained previously will influence investment towards a potential capex solution which is easier to forecast through more traditional means).

184. We urge the Commission to consider other methods to fund flexibility services such as a targeted innovation scheme developed specifically for investment in defined flexibility activities.

185. Another option we proposed during the IM consultation was that the Commission considers a performance-based incentive for avoided peak increase/managed load similar to the Demand Management Incentive Scheme (DIMS)[33] adopted by the Australian Energy Regulator (AER). The scheme encourages distribution businesses to find lower cost solutions to investing in

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[32] Unison, Submission on the IM Review 2023 Draft Decisions, 19 July 2023 p.11

[33] https://www.aer.gov.au/industry/registers/resources/schemes/demand-management-incentive-scheme-and-innovation-allowance-mechanism

network solutions. The incentive scheme achieves this by providing distribution businesses with financial incentives to undertake efficient expenditure on non-network solutions to manage peak electricity demand.

186. We would also like to point towards the Northern Ireland Electricity Networks' approach to innovation[34]. Under their innovation strategy they highlight that they are content to take a 'fast follower' approach to the UK's network companies' innovation:

> *"Over the past decade there has been a plethora of innovation projects undertaken by GB DNOs facilitated through various regulatory mechanisms. We are well placed to leverage the learning from these activities to the betterment of Northern Ireland customers, however, it should be noted that these significant strides forward in GB are not directly transferrable and require tailoring to integrate smart and customers based solutions into business as usual here in Northern Ireland. With that in mind, our approach to innovation during RP6 is to be a "fast follower", integrating suitably advanced smart and customer-based solutions into business as usual. We plan to do this by undertaking a programme of focused pilots with the objective of developing cost-effective alternatives to conventional network investment."*

187. Although EDBs in New Zealand have a proven track record in innovation, the regulatory funding mechanism has been limiting, whereas in Australia the network companies have multiple innovation schemes to make use of and regulatory sandboxing. We believe that the Northern Ireland as a fast follower to Great Britain example might also apply to New Zealand as a fast follower to Australia. It brings into question the additionality principle proposed by the Commission in the Issues Paper. But we believe a fast follow approach to innovation is still appropriate when the innovation benefits the end consumer.

188. The Commission has hinted at holding a targeted workshop on innovation in the new year. We believe this is a good idea and look forward to participating with the aim of either improving the IPA/ INTSA or bringing in a new mechanism modelled on ideas from overseas.

Yours sincerely

Richard Sharp
GM Economic Regulation and Pricing

Appendix – Commerce Commission questions from Issues Paper

[34] https://www.nienetworks.co.uk/future-networks/innovation-strategy

Number	Request for comment or responses on initial views
1	**We are interested in your views on whether we have properly understood the changing industry context as it relates to the DPP4 reset.** Have we properly understood and represented the changing industry context and are there other implications for the DPP4 you believe we should consider?
	See sub-sections: IM review overlap and Inflation
2	**We are proposing to adapt our approach to capex for DPP4 based on feedback from EDBs, that past expenditure is not a good starting point for considering future spend.** Do you have any particular concerns or issues with our proposed approach? If so, how could these concerns or issues be resolved? What alternative data and external sources should we use to support our consideration of capex forecasts, beyond the information in 2023 Asset Management Plans (AMPs), responses to section 53ZD notices and 2024 AMPs, and why should these be used?
	See section: The Capex framework rightfully needs to be reviewed
3	**We are proposing to apply the capital goods price index to forecast capex allocations.** Is there a more appropriate index which could be applied; and, if so, why?
	We will review at cross-submission stage
4	**We have concerns about the challenges in delivering increased programmes of work given current labour market, supply chain and economic challenges in New Zealand.** How should our capex forecast take into account potential sector-wide deliverability constraints?
	See sub-section: Deliverability
5	**We will be using the s 53ZD notice to collect information about how EDBs have reflected resilience in their expenditure forecasts.** What engagement have EDBs had with consumers about resilience expectations, especially as it relates to significant step changes in forecast expenditure? What other considerations should we factor into our analysis of the resilience expenditure information collected from the s 53ZD notice and/or what is unlikely to be visible in the forecasts that we should consider?
	See sub-sections: Consumer engagement, Resilience expenditure in our S53ZD submission, and Resilience and uncertainty.
6	**We would like to understand how potential changes in capital contributions policies could be accommodated in DPP4.** How could changes to capital contributions policies, either in advance of or within the regulatory period, be accommodated within our capex forecasts for DPP4?
	See sub-section: Capital contributions

Number	Request for comment or responses on initial views
7	**We are interested to understand if EDBs are assessing investments driven by expected pace of change which may not be consistent with choices otherwise made under a least cost lifecycle basis.** Are there specific investment decisions being considered due to concerns on delivering increased scale of investment in limited time which are not consistent with a least cost lifecycle basis assessment; for example, areas where EDBs are intending to build well in advance of forecast need or for demand or generation that are only speculative? On what basis are these investments being assessed?
	See sub-section: Anticipatory investment
8	**We are considering updating our approach to forecasting opex input price escalation to better reflect the mix of inputs EDBs face.** Do you have a view on another index, or weighted mix of indices, which would improve the quality of opex forecasting compared to our current approach? (Using a 60/40 mix of percent changes in Labour Cost Index (LCI) all-industries and Producers Price Index (PPI) input indices.) If so, what evidence supports this view?
	We will review at cross-submission stage
9	**We are considering revising our approach to scale growth trend factors, to better reflect EDBs increasing focus on investing to meet growth and renewal needs.** Do you support our emerging view that including forecast capex as a driver of non-network opex could improve opex forecasts, and that this conclusion makes sense in terms of the way EDBs run their businesses? Are there alternative drivers that we should consider, and what evidence is there that they can meaningfully predict EDB scale growth?
	See section: The Opex framework remains stuck in the past
10	**EDBs have identified that insurance costs have been increasing at a greater rate than other costs they face.** What evidence do you have about how these costs are likely to evolve over time? Is the option of trending insurance opex forward using a separate cost escalator workable? How could incentives on EDBs to make risk management decisions be maintained?
	See sub-section: Insurance costs
11	**Given the possibility of a greater need for step-changes in opex in a context of industry transition, we have clarified further how we are thinking of applying the step-change criteria and the supporting evidence we expect.** Do you consider the expanded descriptions of the step-change criteria provide sufficient clarity about the types of step-changes we consider meet the Part 4 purpose?
	See section: The Opex framework remains stuck in the past

Number	Request for comment or responses on initial views
12	**Our initial view is to maintain the principle of no material deterioration and set quality standards on a basis consistent with that established in DPP3.** Do you agree with our proposed approach of maintaining the principle of no material deterioration and setting the quality standards on a basis consistent with DPP3? With regard to the quality standards, are the existing reporting obligations appropriate?
	See section: Quality standards and incentives
13	**Our initial view is to maintain the DPP3 settings of a 10-year reference period updated for the most relevant information and normalisation approach for major events.** Do you think that we should maintain a 10-year reference period updated for the most relevant information and normalise major events on the same basis as DPP3?
	See section: Quality standards and incentives
14	**Our initial view is step changes in reliability, if appropriate, may be accommodated through setting of values or revisions to definitions.** Are there identifiable step changes to reliability parameters for quality standards to manage operational or situational changes outside the control of the distributor compared to historical periods? What value and challenges do you see with different approaches to addressing inconsistencies in the recording of interruptions, the 'multi-count' issue, using either a proxy allocation basis or requiring a recast dataset? Are there alternative approaches which may appropriately address the issue?
	See sub-section: Reliability step changes
15	**Our initial view is to not introduce new additional quality of service measures.** Are there any other quality of service measures beyond those currently required within DPP3 that we should consider introducing, and why?
	See section: Quality standards and incentives
16	**Aurora Energy is scheduled to rejoin the DPP from 1 April 2026.** Do you agree with how we propose to transition Aurora Energy to the DPP in 2026?
	We will review at cross-submission stage
17	**Section 53M(5) allows us to reduce the regulatory period if this would better meet the purposes of Part 4 of the Act. We are considering whether we should reduce the regulatory period from five to four years.** What particular challenges do you perceive may arise from shortening the regulatory period? What are the potential benefits to consumers from maintaining or shortening the length of the regulatory period?
	We will review at cross-submission stage

Number	Request for comment or responses on initial views
18	**The DPP sets annual deadlines by which suppliers must make Customised Price-Quality Path (CPP) applications to enter into effect the following year.** Do you support retaining a similar approach to setting CPP application windows as was undertaken for DPP3?
	We will review at cross-submission stage
19	**The current IMs provide for a discretionary shortening of asset lives.** Do you have views on the framework for assessing accelerated depreciation applications?
	We will review at cross-submission stage
20	**Our initial view for DPP4 is to retain revenue-linked quality incentives for both planned and unplanned SAIDI, with targets, caps, collars, incentive rate and revenue at risk set on a consistent basis with DPP3.** Are EDBs considering the quality incentive scheme (QIS) in their investment decisions? Do you consider the proposed settings are appropriate for the QIS, including whether the incentive rate is driving appropriate outcomes with regards to consumer quality expectations?
	See section: Quality standards and incentives
21	**Caution around treatment of non-performance of less proven solutions may create a reticence by EDBs to implement these types of solutions and result in a focus on more proven established technologies, typically, capex investments. Our intention is that the compliance with the quality standards and penalties under the QIS do not act as a potential impediment to innovation.** How should we account for non-performance of non-network solutions (regulatory sandboxing)?
	See section: Quality standards and incentives
22	**The regime's baseline incentives may be insufficient to support innovation, such that we consider it is appropriate to have an innovation (and/or non-traditional solutions) incentive scheme.** Do you agree with our understanding of the regime's baseline incentives to support innovation, and the need for an innovation and/or non-traditional solutions scheme? Would you be interested in participating in a targeted workshop, and if so, are there any topics you consider should be covered?
	See section: An opportunity to improve innovation with the DPP

Number	Request for comment or responses on initial views
23	**We are interested in feedback on our initial thinking about how to design an incentive scheme to encourage innovation and/or non-traditional solutions in DPP4.** What are your views on the key principles (see **Attachment I**)? Are they effective as the basis of an innovation and/or non-traditional solutions scheme? Are there others you think may be suitable? What are your views on the potential scheme design characteristics? Are they effective as the basis of an innovation and/or non-traditional solutions scheme? Are there others you think may be suitable? How could these principles and characteristics be best applied in designing a potential scheme? We would also welcome submissions with examples of overseas schemes/characteristics that you consider appropriate for a DPP.
	See section: An opportunity to improve innovation with the DPP
24	**Our initial view is that a specific demand-side management and energy efficiency scheme is not required for DPP4.** Is there a basis for strengthening the incentives for energy efficiency and demand-side management initiatives?
	See section: Incentives for energy efficiency and demand-side response (DSR)
25	**We are not proposing to implement a QIS for line losses. We believe EDBs improved visibility of low voltage performance and improvements to the energy efficiency of distribution transformers should drive improvements in DPP4 without additional explicit incentives.** Do you agree with our approach to not introduce a specific QIS related to reducing energy losses?
	We agree that a specific QIS related to reducing energy losses is not required
26	**We are proposing to retain our approach of setting a 'default' X-factor of 0% (before considering price shocks or supplier financial hardship).** We are interested in your views on whether this approach (where long-run changes in sector productivity are accounted for in our building blocks analysis) remains appropriate.
	See section: Productivity metrics do not account for EDBs' growing roles
27	**Our emerging view is to assess price shocks for consumers using the real change in aggregate distribution revenue from year-to-year, with a particular focus on the change between regulatory periods.** Do you agree with this approach? If not, are there other alternatives we should consider? When applying this (or any other) analysis, what factors should we consider in determining whether a price change amounts to a price shock?
	See sub-section: Consumer price shocks

Number	Request for comment or responses on initial views
28	**Our emerging view is 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.** Do you agree with this approach? If not, are there other alternatives we should consider? When applying this (or any other) analysis, what factors should we consider in determining whether a supplier faces undue financial hardship?
	See section: Decisions around financeability are crucial and must be brought forward
29	**Previously we have forecasted indicative consumer bill impacts from information disclosed by EDBs. We are interested in understanding what other information may help refine our approach.** What models or data inputs could be provided by EDBs which would improve our approach to modelling consumer bill impact?
	See sub-section: Consumer impact model