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Ben Woodham

Electricity Distribution Manager

Commerce Commission

Infrastructure Regulation

Wellington

Email: infrastructure.regulation@comcom.govt.nz

Submission on EDB DPP4 Reset

Background

1. The Commerce Commission (the Commission) published the default price-quality paths for electricity distribution businesses from 1 April 2025 issues paper on the 2nd of November 2023[1] as part of the preparation for DPP4 (2025-2030).
2. The Commission included 29 questions, requesting stakeholder feedback[2].
3. The themes from the Issues Paper include:
   - Enabling investment to meet consumer demands
   - Incentivising efficiency and innovation
   - Setting revenue allowances and price impacts
   - Summary of IM Reviews 2023 that may be implemented in the revenue path for DPP and CPP
   - Forecasting operating and capital expenditure
   - Setting quality standards and incentives
   - Determining rates of change
   - Incentives, including innovation.
4. We have reviewed the Issues Paper and provide submission to the Commission's questions in attached Appendix A.
5. We have contributed to and support the ENA submission .

[1] https://comcom.govt.nz/__data/assets/pdf_file/0025/332944/Default-price-quality-paths-for-electricity-distribution-businesses-from-1-April-2025-Issues-paper-2-November-2023.pdf

[2] https://comcom.govt.nz/__data/assets/word_doc/0026/332945/Default-price-quality-paths-for-electricity-distribution-businesses-from-1-April-2025-Summary-of-consultation-questions.docx

Summary

Orion's region is experiencing upper quartile connections growth of 1.7% per annum, when compared to other EDBs, while facing uncertainty around government policy on housing density that can have material impact on upstream (shared) network reinforcement needs. Forecast lifecycle maintenance and renewal levels are consistent over time however input costs have significantly increased due to inflation (impacting both materials and labour) putting pressure on how much can be achieved with the same money.

Decarbonisation for our region means process heat conversion and electrification of transportation with customer decision making primarily driving the timing. Of the thirty-nine (39) commercial and industrial customers identified by EECA/Orion (~80MW) most likely to switch their process heat to electricity over the next ten years across our network, only one (1) is greater than 10MWs, four (4) are likely to be greater than 5MWs, another five(5) between 2-5MW and the remainder (74%) being less than 2MWs. It is clear many process heat conversations will not meet the Commission's 5MW threshold for the Large Capacity Customer reopener.

Operational cost shifts including insurance, cybersecurity, and moves to SaaS software as part of our data, digitisation and technology roadmap are a changing dynamic for us. Our customers, both urban and rural, are telling us during engagement that their highest spending priority for us is resilience ahead of future readiness, sustainability, capital and operational efficiency, customer experience and safety.

The DPP4 process is an important decision with the overlay of an urgent need to respond to the net carbon objective and lift-up New Zealand's infrastructure. The Commission's IM decision has provided for some of the necessary shifts needed for DPP4 such as:

- inclusion of in-period adjustments/reopeners to provide agility around responding to customer needs in an environment of uncertainty, and efficient design and quick, inexpensive processing of these will also be important
- alterations to the IRIS mechanism to prevent undue hardship from inflation effects
- treatment of transmission as a pass-through cost (in relation to the 10% price cap).

For the DPP4 regime to enable sufficient investment to improve resilience, facilitate decarbonisation and demand management, and deliver safe and reliable services for our customers, the DPP decision will need to deliver:

- adequacy of cashflow (reference answers to chapter 3, questions 27 and 28)
- sufficient capex and opex to address high connections growth, process heat, transport electrification and necessary ongoing replacement and renewal in a high inflation environment (references answers to questions 6 and 7)
- acceptance of some opex step changes (reference answers to questions 1, 5, 9, 10, 11,14, 25, 26)
- removal of the arbitrary 120% capex cap to provide realistic capex assessment that addresses the levels of investment needed (reference answer to question 2)
- establishment of incentives under Section 54Q around demand management and energy efficiency in support of DER management and non-traditional investment (reference answers to questions 1, 4, 11, 21 and 24) so we optimise costs for customers and so that participation of DER increases over time
- an effective innovation and non-traditional solutions allowance design (reference answers to questions 22 and 23)
- provision for customer engagement both when planning work programmes and when executing them (reference answer to question 11).

Concluding Remarks

We do not consider any part of this submission to be confidential. Please do not hesitate to contact us on 03 363 9898 should wish to discuss our submission.

Yours sincerely

Dayle Parris
Head of Regulatory and Commercial

Appendix A- Orion's Feedback Specific Questions

Chapter 2 – Context and challenges (page 18)

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?

1 Response:

We agree that the challenges EDBs have experienced during DPP3 and will going forward include:

- Decarbonisation and increased electrification
- Resilience of EDB infrastructure
- Innovation and advances in technology
- Significant inflation and supply chain cost pressures.

This has the effect of translating to an uplift in expenditure for Orion, and that the Commission should consider, due to:

- extensions and/or augmentation for process heat conversions,
- industry specific cost pressures for labour and materials which increases costs to do the same volume of work,
- increased need for knowledge of the low voltage system to support electrification of transport, infill-housing and growth,
- reassessment and planning for different design standards and consideration of adaptation to support resilience,
- work programmes to support digital integration and increased cybersecurity for resilience, information transparency and efficiency,
- non-network alternatives to traditional network build including demand side management, optimising network operation and DER management,
- the value in undertaking trials and pilots on new approaches that could increase efficiency and support innovation and learning with partners.

The particular contextual environment of this DPP4 decision, the need to electrify our economy, means the reliance on electricity will only increase and the need to provide a safe and reliable service while sharing benefits of efficiency with customers is critical to ensure long term benefit of consumers.

We submit that to meet the Part 4 purpose and the long-term benefit of consumers the Commission must consider:

- applying financeability assurance considerations to its reset decision so that there is confidence the decision will not undermine their ability to prudently and efficiently provide for safe, reliable and resilient assets and service
- the role of Section 54Q as an incentive for DER management and non-traditional solutions
- further principles for the innovation and non-traditional solutions allowance.

Chapter 3 – Forecasting capital expenditure

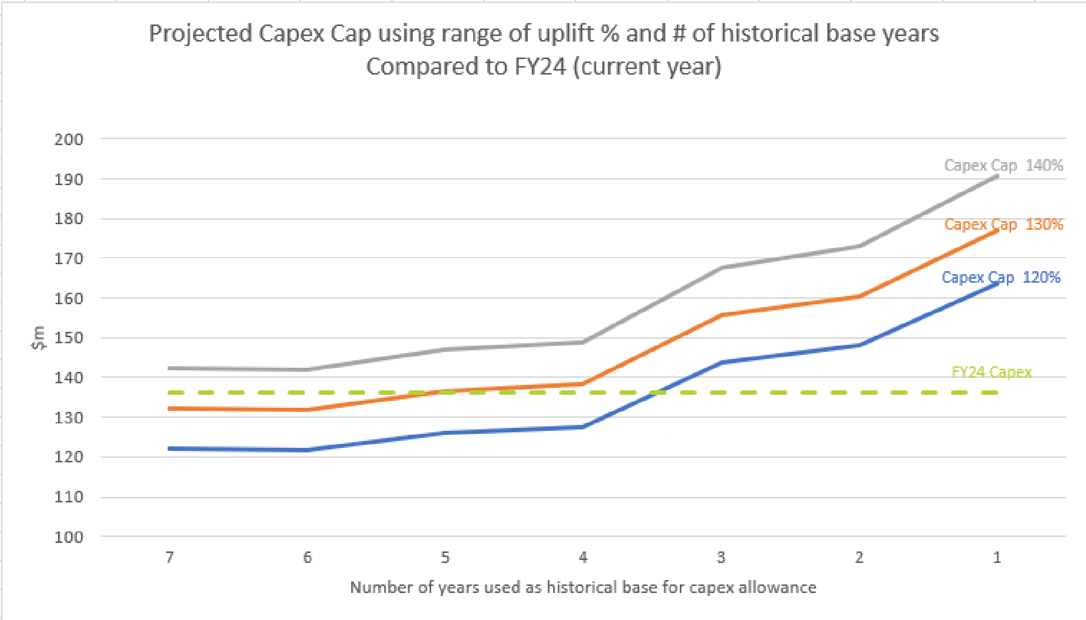
2 We are proposing to adapt our approach to capex for DPP4 based on feedback from EDBs, that past expenditure is not a good starting point for considering future spend.

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?

2 Response:

There is a risk to customers from capex underinvestment or capex investment at the wrong time e.g., too late. By comparing length of capex base period to options for capex step (or cap) against current Orion FY24 expenditure levels the illustrative chart below, shows that the base period is probably more statistically significant than the "step" (currently 120%). Importantly, even by adjusting both parts of the methodology, the resultant allowance risks forcing a relatively small (or even potentially a backwards step) from current investment levels at a time more investment is required. A key driver over the last period has been the industry specific cost increases over and above CPI which have impacted capex cost. Without an allowance keeping pace, we will be forced to do lower volumes of work, as naturally higher prices will utilise the allowance more rapidly.



Orion submits that its key concerns with the Commission's approach to DPP4 for capex is:

- the capped historical approach for capex allowance setting,
- the potential for Electricity Authority direction on connection charges during DPP4 which could inadvertently lead to penalties under IRIS and put pressure on any capex allowances already provided,

Orion submits potential resolutions to these concerns are:

- a preference for a shortening of the capped historical approach period and a removal or lifting of the arbitrary 120% cap
- a verified and unverified approach to capex forecasts.

  - using the information provided in 2024 AMPs, the 2023 AMP review and the 53ZD request, and other reports in the public domain such as the EECA/RETA report for North Canterbury (Orion and MainPower)[3] can provide opportunity for further scrutiny, explanation or
  - other independent reports for unverified capex or use of in-period adjustments/reopeners to provide avenue to address these
- in accordance with section 54V of the Commerce Act[4] reopen the DPP in the event the Authority regulates connection charges

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?

3 Response:

The Capital Goods Price Index is a broadly appropriate measure. However, it may fail to capture the true price inflation that drives EDB capex. Orion is not aware of any measure that would provide greater accuracy.

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?

4 Response:

Orion has right sized its investment plans based on expected delivery capability and we have the means along with our service providers to deliver the investment needed if we have the allowances to facilitate it. We are confident that we can both grow our own talent and source it to support deliverability. Inflation is the more significant factor in overall cost increases as opposed to the quantity of work which is what drives deliverability. Expenditure forecasts comprise both volume and cost pressures therefore backing out the impact of inflationary affects is a better gauge of volume for deliverability e.g., for Orion replacement and renewal volumes are consistent into DPP4.

In the last 2-3 years Orion has experienced inflation within our industry above national economy-wide inflation. Our analysis indicates a weighted average annual price rise above PPI of 14%. The table below indicates key components driving these increases for us.

[3] https://www.eeca.govt.nz/co-funding-and-support/products/north-canterbury-regional-energy-transition-accelerator/

[4] https://www.legislation.govt.nz/act/public/1986/0005/latest/DLM1940060.html- Section 54V Impact of certain decisions made under Electricity Industry Act 2010

	Annual price rise above PPI
Materials associated with O/H work	15%
Materials associated with U/G works	12%
Plant	-1%
Traffic Management	23%
Approx weighted average	**14%**

This means that network capex that costs us $1m today is forecast to cost us more than this in FY30 in real $ terms. There is a risk that PPI inflation will continue driven by decarbonisation, so there is a real need to move away from PPI only approach when forecasting real spend on materials.

Orion submits that, provided allowances are appropriate including being reflective of the current economic environment relevant to our particular sector, we and our service providers are confident we can deliver the foundational expenditure as we have historically and with adequate in-period adjustments/incentives/allowances can accommodate other requirements related to customer decarbonisation, innovation, resilience and DER management.

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?

5 Response:

Orion has examined the external forces and uncertainties shaping the electricity industry. This work informed our initial views on future scenario modelling. **We have engaged with external stakeholders to stress test our scenarios** and understand what stakeholders see as strategic considerations necessary for adapting to evolving trends, technologies, and regulatory frameworks over the next three decades. This resulted in a further evolution of our future scenario modelling which informs our planning and expenditure forecasts. More information on these scenarios and their implications will be available in Section 2 of our 2024 AMP.

In addition, in our latest "Powerful Conversations" workshops we asked around 50 customers to rank investment priorities. Through two workshops, one with urban and one with rural customers, participants ranked resilience, operational, efficiency, future readiness, sustainability, customer experience and safety in order of importance. We wanted to understand how customers would prioritise spending. **Our customers have told us that resilience spending is most important to them** with urban customers weighting resilience spending highest at 39% and rural customers weighting resilience spending highest at 27% of a 100% pool of money. A recent and significant resilience project, laying of new 66kV cable between our Milton and Bromley substations and through our CBD, has involved direct engagement with customers as work progresses[5].

[5] https://www.haveyoursay.oriongroup.co.nz/bromley-to-milton-cable

Unlike the project mentioned above, resilience is not often a stand-alone capex project/cost category but is embedded in the way EDBs design, build, operate and maintain their networks. Community resilience also depends on systems/network effects which include non-EDB infrastructure i.e., telecoms, roading and transport.

We note the Commission should consider resilience implications from two sector workstreams:

- actions identified in Aotearoa New Zealand's First National Adaptation Plan such as Te Waihanga's action to scope a resilience standard or code for infrastructure[6], and actions identified in Aotearoa New Zealand's First Emissions Reduction Plan such as:
    - to develop energy strategies for Aotearoa and action
    - to decarbonise Aotearoa industries.[7]

- impacts on expenditure from the Electricity Authority work on the Future Security and Resilience programme.[8]

For adaptation, managed retreat and system resilience EDBs may be directed by local councils or the Electricity Authority to take actions during DPP4 that are unclear at present. We note that the Commission's IM decision provides some reopener in-period mechanisms that may address these types of resilience expenditure.

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?

6 Response:

Capital contributions is a workstream which is currently being considered by the Electricity Authority (EA) work programme. The Authority is concerned with, among other things, incentivising the uptake of DER participation including installation of public EV chargers. Capital Contributions were included in the EA's distribution pricing practice note in 2021.[9]

EDBs forecast their contributions in Schedule 11a of the Asset Management Plan in line with their connection charge policies/methodologies.[10] Any guidance or change in regulation could materially impact the expenditure forecast balance between capex and contribution, and impact IRIS outcomes.

We submit that the DPP should be re-opened for policy changes, either by the Government or regulators including the Electricity Authority, that alter the balance of EDB's recovery of capex from access seekers during DPP4.

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

[6] See https://environment.govt.nz/publications/aotearoa-new-zealands-first-national-adaptation-plan/adaptation-options-including-managed-retreat/ and Action 5.6
[7] See https://environment.govt.nz/publications/aotearoa-new-zealands-first-emissions-reduction-plan/energy-and-industry/
[8] https://www.ea.govt.nz/projects/all/future-security-and-resilience/
[9] https://www.ea.govt.nz/documents/1882/Distribution_Pricing_Practice_Note_2021_2nd_edition_-_final.pdf
[10] https://www.oriongroup.co.nz/assets/Company/Corporate-publications/Orion-AMP-March-2023.pdf

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?

7 Response:

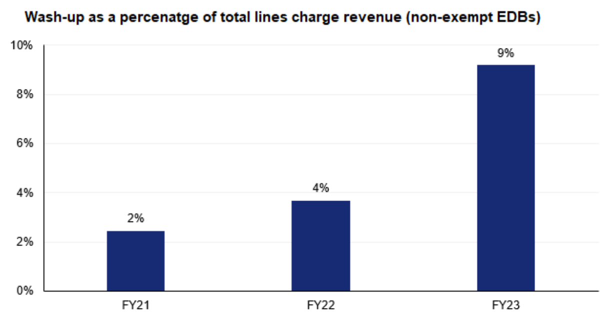
Orion works hard to deliver at the right time, place and cost including on a least cost lifecycle basis. The customer engagement that informs our scenario modelling and the asset management practices we employ underpins our good industry practice in expenditure forecasting and work programme planning. However, the high rate of connections in our region from organic growth before taking into account uplift from decarbonisation (process heat, grid scale solar, EVs) has raised a consideration for capex investment in strategic land locations. There is considerable lead time involved in land acquisition and consenting that can be alleviated, in terms of impact on fast-paced delivery of a high capital project, by upfront attention to this aspect of the planning cycle.

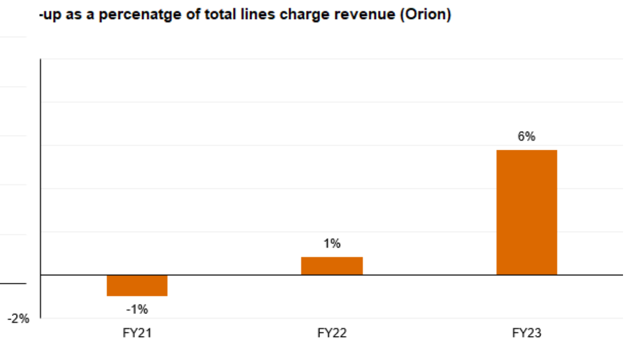
We submit that land acquisition could be an area for agility in the regime that could unlock response times for when growth/decarbonisation reaches critical levels triggering security of supply related substation investment.

Chapter 3 – Forecasting operating expenditure

Orion submits that the Commission's historical approach to setting opex allowances is overlooking significant input cost increases including from inflation, and additional outputs we are delivering e.g., shortened response times and prevention of faults by employing technology such as drones for fault finding and detecting defects in hard-to-reach parts of our network.

At a high level, across non-exempt EDBs, analysis shows that there is an 8% opex allowance overrun ($46m) at the end of FY23 largely driven by high inflation and this is projected to be 13% by FY25 ($78m) based on current AMPs. Importantly this translates to 9% of revenue ($184m) not being able to be recovered due to revenue cap limits at the end of FY23 i.e., it is held in wash-up balances (see graph below). For Orion this translates to 6% of revenue ($13.3m) not being able to be recovered due to revenue cap limits at the end of FY23 (see graph below). We submit that the Commission should consider how the revenue washup can be recovered into DPP4.





One of the major issues we see with the base step trend approach (as used in DPP3) 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. We discuss some of these in our answers to questions 8 to 11 below.

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?

8 Response:

Orion supports ENA's submission on this point.

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?

9 Response:

The information disclosures define non-network opex as:

> *"the sum of operational expenditure relating to system operations and network support, and business support"*

The information disclosures define Capital expenditure to mean:

"(a) in relation to the unallocated works under construction, costs-

> *(i) incurred in the acquisition or development of an asset during the disclosure year that is, or is intended to be, commissioned; and*
>
> *(ii) that are included or are intended to be included in the value of assets commissioned relating to the unallocated RAB;*

(b) in relation to the Report on related party transactions, costs-

> *(i) incurred in the acquisition or development of an asset during the disclosure year that is, or is intended to be, commissioned; and*
>
> *(ii) that are included or are intended to be included in the value of assets commissioned relating to the RAB; and*
>
> *(iii) that are as a result of related party transactions;*

(c) in all other instances, costs-

> *(i) incurred or forecast to be incurred in the acquisition or development of an asset during the disclosure year that is, or is intended to be, commissioned; and*
>
> *(ii) that are included or are intended to be included in the value of assets commissioned relating to the RAB"*

In terms of how Orion runs its business we agree that a relationship can exist between non-network opex and network capex. In our 2023 AMP we highlighted three areas impacting an uplift in non-network opex:

- system operations and network support team opex
- business support opex
- a range of data, digitisation systems that support operation of our network, examples could include upgrading load management software and systems, modelling development, licensing, cybersecurity, network operational software updates, cybersecurity, cloud services, data management and analytics.

If Capex involves acquisition, development and an intention to commission an asset then consequential non-network opex from this network capex activity could include:

- training such as for use and operation of new types of equipment or technology
- research and development
- support costs for modelling climate related risk in support of network asset management planning and work programmes (sustainability)
- legal costs relating to connection arrangements
- internal (FTEs) and external financial advice
- internal (FTEs) and external legal advice
- internal (FTE) data, digital and technology activities related to rolling out roadmap of improvements to information and technology systems and asset management systems[11].
- activities related to network transformation roadmaps such as for low voltage modelling and related asset management
- fleet management such as lifecycle change out to electric fleet

Orion submits that we support the Commission's conclusion that forecast capex as a driver of non-network opex could improve opex forecasts.

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?

10 Response:

Our total insurance premiums, since 2018 have increased by 62% while reducing coverage levels in an attempt to prudently manage costs. According to our 2023 Information Disclosures[12], insurance constitutes 4% of Orion's operational expenditure.

Orion continues to see price increases on our insurance programme and with a hardening of the liability market our insurance premiums have steadily increased since 2012. With a 12% increase

[11] The relationship may differ between EDBs depending on their accounting approach to capitalisation.

[12] https://www.oriongroup.co.nz/assets/Company/Regulatory-Disclosures/FY23-Information-Disclousures-FINAL-Website-Version.pdf

across our liability and material damage programmes in the most recent year.

The main drivers for cost escalation are underwriter's view of the amount of climate related events internationally along with New Zealand's earthquake history and the risk of an AF8 event. Lloyds of London have ranked Aotearoa second across all nations for losses due to natural hazards in 2018 and our most recent experiences with flooding and cyclones only reinforces this earlier view[13].

In terms of risk mitigations, insurance underwriters are requiring EDBs to model their highest risks – for example for Orion EQ and flood. The only lever available to reduce premiums in a traditional insurance market (not a parametric or captive) is to look at loss limits for natural disasters. This will only be achieved by modelling scenarios with insurers and increasing expenditure on resilience to mitigate the impact of such events.

The limited ability of EDBs to mitigate the frequency or impact of these events, like imprudent substitution of overhead line with underground cables, makes insurance a natural candidate for individual cost escalation or step change. There is a natural incentive on EDBs to make risk management decisions on insurance input costs to limit financial shock/business interruption and be in a position to restore supply in line with their role as a lifelines utility as well as minimise costs for consumers. The addition in the IM decision of a resilience reopener provides an incentive to maintain risk management decisions around resilience that may be enabling in terms of insurance cost levels.

We submit that the Commission should seek advice from the insurance sector to understand their approach to our sector.

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?

11 Response:

The information disclosures define network opex as:

> *the sum of operational expenditure relating to service interruptions and emergencies, vegetation management, routine and corrective maintenance and inspection, and asset replacement and renewal.*

The information disclosures define the opex related activity of these particular network assets as:

Service interruptions and emergencies means

> *"….operational expenditure where the primary driver is an unplanned instantaneous event or incident that impairs the normal operation of network assets.* [14]

Vegetation management means

> *"….operational expenditure where the primary driver is the need to physically fell, remove*

[13] https://www.ajg.co.nz/news/new-zealand-second-in-the-world-for-natural-disaster-costs/

[14] Noting: *This relates to reactive work (either temporary or permanent) undertaken in the immediate or short term in response to an unplanned event. Includes back-up assistance required to restore supply, repair leaks or make safe. It also includes operational support such as mobile generation used during the outage or emergency response. It also includes any necessary response to events arising in the transmission system. It does not include expenditure on activities performed proactively to mitigate the impact such an event would have should it occur. Planned follow-up activities resulting from an event which were unable to be permanently repaired in the short term are to be included under routine and corrective maintenance and inspection.*

or trim vegetation (including root management) that is in the proximity of overhead lines or cables. It includes expenditure arising from the following activities-

(a) inspection of affected lines and cables where the inspection is substantially or wholly directed to vegetation management (e.g., as part of a vegetation management contract). Includes pre-trim inspections as well as well as inspections of vegetation cut for the primary purpose of ensuring the work has been undertaken in an appropriate manner

(b) liaison with landowners including the issue of trim/cut notices, and follow up calls on notices;

(c) the felling or trimming of vegetation to meet externally imposed requirements or internal policy, including operational support such as any mobile generation used during the activity.[15]

Routine and corrective maintenance and inspection means

"…. operational expenditure where the primary driver is the activities specified in planned or programmed inspection, testing and maintenance work schedules and includes-

(a) fault rectification work that is undertaken at a time or date subsequent to any initial fault response and restoration activities

(b) routine inspection

(c) functional and intrusive testing of assets, plant and equipment including critical spares and equipment

(d) helicopter, vehicle and foot patrols, including negotiation of landowner access

(e) asset surveys

(f) environmental response

(g) painting of network assets

(h) outdoor and indoor maintenance of substations, including weed and vegetation clearance, lawn mowing and fencing

(i) maintenance of access tracks, including associated security structures and weed and vegetation clearance

(j) customer-driven maintenance

(k) notices issued."

Asset replacement and renewal means

"…(b) ….operational expenditure where the primary driver is the need to maintain network asset integrity so as to maintain current security and/or quality of supply standards and includes expenditure to replace or renew assets incurred as a result of-

[15] Noting: The following activities and related costs are excluded from this category- (a) general inspection costs of assets subject to vegetation where this is not substantially directed to vegetation management (include in routine and corrective maintenance and inspection); (b) costs of assessing and reviewing the vegetation management policy (include in system operations and network support); (c) data collection relating to vegetation (include in system operations and network support); (d) the cost of managing a vegetation management contract, except as stated above (include in system operations and network support); (e) emergency work (include in service interruptions and emergencies)

• the progressive physical deterioration of the condition of network assets or their immediate surrounds;

• the obsolescence of network assets;

• preventative replacement programmes, consistent with asset life-cycle management policies; or

• the need to ensure the ongoing physical security of the network assets."

The Commission has outlined the approach it has taken in previous resets to step changes and that these are considered criteria that remain appropriate:

"At past resets, we have required any step change to be:

3.57.1 significant.

3.57.2 robustly verifiable.

3.57.3 not captured in other components of our projections.

3.57.4 largely outside of the control of EDBs.

3.57.5 be applicable to most, if not all, EDBs."

We submit that analysis of Schedule 6b of the Information Disclosures Data[16] shows that operational expenditure across all EDBs has increased by 25% over the past 5 years, an average of 5% per year. This could be symptomatic of incremental increases in opex from activities and increased outputs.

The Commission has identified a number of step changes cited through previous submissions during the reset process. We agree with the items the Commission has identified and provide additional detail on these and we highlight some further items:

- prudent, consistent and continued replacement and renewal of an aging asset portfolio
- increased frequency of emergencies from extreme weather[17]
- increased focus on vegetation management to mitigate impacts of more vegetation planting by customers in line with high connection growth, and adverse resilience outcomes including employing technology to improve efficiency and effectiveness[18]
- D111.1 demand changes due to electrification- we have experienced increased costs for legal and consultancy advice from negotiation of individual construction contracts, delivery services agreements or handover deeds for complex decarbonisation projects, and technical and solution studies for distribution and transmission for complex projects.
- D111.3 data and digitisation costs–
    - Orion recently signed up with BlueCurrent[19] for the delivery of smart meter data. In line with our data and digitisation roadmap to access insights from data, expenditure will occur on automating processes and data intelligence, building on how we manage,

[16] https://comcom.govt.nz/__data/assets/file/0018/302436/Electricity-distributors-information-disclosure-data-2013-2023.xlsm

[17] https://niwa.co.nz/our-science/climate/information-and-resources/clivar/scenarios

[18] https://www.powerco.co.nz/what-we-do/our-projects/pole-top-photography-and-lidar

[19] https://www.energynews.co.nz/news/electricity-metering/149618/vector-metering-rebrands-moves-4g-iot-network

analyse and report that data as a normal course of business. Data access and use has been cited as a key enabler for facilitating DER management for long term benefit of consumers in the Authority's [Delivering key distribution sector reform (ea.govt.nz)](). We anticipate that other EDBs will follow suit with a step change in meter data costs being commonplace across EDBs.

  - improvements in efficiency from operational training in and use of new technology such as drones for routine inspection, and use of in field mobile data collection tools for as-build information and maintenance decision making

- D111.5- cybersecurity costs to bolster Orion's systems and secure our data
- D111.6 insurance increases- refer to our answer to question 10 for details on this uplift.

Expenditure we have identified which is over and above actual historical expenditure that we believe could also meet some of the step change criteria are:

- a step change in expenditure for customer engagement;
  - during major complex projects that impact the community
  - communications on safety messaging to prevent unsafe public practices of accessing our network for financial gain and to improve physical security where possible

- D111.1 Demand changes due to electrification- we anticipate a step change in payments for DER management services. There is a huge opportunity for EDBs to maximise the orchestration of distributed energy resources (DER) to avoid network constraints and minimise costs to consumers. To enable these functions for networks, EDBs will need to expand their capabilities. Unfortunately, while these costs, once established, are recurring in nature, we do not believe that forecasting costs is possible to the degree that will 'robustly verify' them to the Commission, they rely on a market from other parties (aggregators) responding to expressions of interest and being able to mee the need that would defer the capex investment, and that the piecemeal nature of these types of expenditure would not lend themselves to reopeners.

  The sector should not miss the opportunity to enable flexibility markets. We note below what the Authority is already doing in this space and that they recently:

  - made Code changes to enable fleets of distributed batteries to offer instantaneous reserves
  - 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
  - encouraged EDBs to shift to time-varying distribution pricing, which further encourages aggregator activity.

  We recommend that the Commission considers ways to facilitate access to expenditure related to DER management (flexibility services) and/or when that payment is to a particular flexibility provider the Commission should consider as a pass-through cost. We do not consider that the innovation and non-traditional solution allowance would accommodate these funds in a timely manner.

  The energy transition requires fast-moving, agile 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"*[20]

We submit that the Commission could also consider whether there is a case for some step changes to be considered as a pass through such as insurance.

We submit that key step changes to consider are insurance, payment for smart meter data, DER management, cybersecurity and customer engagement.

Chapter 3 – Quality standards

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?

12 Response:

Orion submits conditional agreement to the continued principle of no material deterioration and setting quality standards on a basis consistent with that established in DPP3. The condition is that if customers are willing to pay to maintain current levels and there is sufficient revenue via the DPP to maintain those levels.

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?

13 Response:

Orion submits agreement that the 10-year reference period updated for the most relevant information and normalisation approach for major events should be retained. A shorter period may risk omitting periods of frequent clustered events and not take into account differing regional patterns/timings e.g., Vector's more recent spate of events versus Orion's more recent benign period. Consideration of a shorter period was made when Orion moved from their CPP to the DPP, and it was concluded that the 10-year reference period remained appropriate, and this has been true in practice.

Orion submits that due to the expected increase in extreme weather events from climate change moving forward, the expectation of 2.3 major event days per annum may no longer hold. Orion encourages the Commission to engage with NIWA to ensure the MED expectation in the DPP aligns with the government's scientific advice.

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

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?

14 Response:

Orion submits that there is a risk that deferral of capex in favour of opex non-traditional solutions may carry a risk of increased reliability issues until these approaches are fully tested in earnest. This may need to be considered when reviewing quality results and incentives.

Orion already reports on a multicount basis.

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?

15 Response:

The Commission introduced a number of improvements and incentives as well as splitting planned and unplanned reporting during DPP3. We submit in agreement to the Commission's position not to introduce new additional quality of service measures for DPP4.

Chapter 3 – Other issues

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?

16 Response:

We endorse the ENA submission on this point.

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?

17 Response:

Setting the 5-year regulatory periods (DPP) is a resource intensive process for both EDBs and the Commission however it does provide a period of relative certainty for stakeholders once set. We submit in favour of retaining the current 5-year regulatory period.

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?

18 Response:

Yes, we support a similar approach with annual deadlines being appropriate.

19 The current IMs provide for a discretionary shortening of asset lives.

Do you have views on the framework for assessing accelerated depreciation applications?

19 Response:

We refer to the following sections of the DPP Issues Paper:

> *"G26 Increasing deployment of emerging technologies potentially changes the risk to EDBs' ability to fully recover their invested capital, under existing physical asset lives assumptions set out in the IMs.*
>
> *G30 No later than 13 months prior to the commencement of DPP4, EDBs may apply to us for 'an adjustment factor'. We propose to include a draft response to any such applications received as part of our draft DPP4 decision, similar to the approach undertaken in DPP3."*

We agree in principle with the mechanism for accelerated depreciation however in practice evidence of an increasing number of customers off-griding and/or being unable to attract investment (due to risk) would no doubt be needed at which point reducing asset lives by 15% may be too little too late.

Chapter 4 – Quality incentives

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?

20 Response:

Orion submits its agreement to retaining the revenue-linked approach to quality incentives. We do actively monitor our progress against targets, caps, collars and revenue at risk and report at Board level. However, we do question if the incentive scheme incentive rates (in our case $15,843 $/SAIDI min planned before planned notification incentive reductions, and $31,686 $/SAIDI min unplanned) are providing a strong enough incentive signal. A stronger signal might drive some improvements if this was consistent with customer preferences .

The planned notification incentive was complex to implement, and it is still too early to gauge whether the benefits have outweighed the costs.

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)?

21 Response:

Orion is working with Flexforum and other industry participants researching and trialling non-network solutions. Orion is also trialling flexibility as part of its Lincoln Flexibility Trial.[21] The potential for reduced reliability can be a concern when trialling new approaches.

However, we are more concerned that we have not been able to access the Innovation Allowance during DPP3 for DER management or non-traditional solutions. We would suggest that applying a less onerous non-performance quality criteria, to this type of project applied for under the innovation allowance, would be an appropriate way to account for non-performance of non-traditional solutions. Alternatively, there could be a provision for a reduction in SAIDI/SAIFI from a successful trial under the innovation allowance.

Chapter 4 Innovation

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?

22 Response:

We submit in support of a well-designed innovation allowance. We welcome the decision to remove an engineer's independent assessment report from the approval process to access the innovation allowance.

The current design of the innovation allowance still requires improvement including

- providing for a greater level of innovation allowance,
- allowing for sharing of allowance as part of partnered solutions,
- allowing for up front allowance rather than waiting for a project to complete.

During 2023 there has been strong sector feedback about the importance of whole of system thinking, and the need for regulatory alignment between the Commission and the Authority. We submit that the Commission should consider whether there is benefit in one of the possible qualifying aspects of an application being a linkage between the work programme of the Authority and the innovation activity applied for under the innovation allowance e.g., innovative projects that enable participation of DER.

Orion would welcome and support a targeted workshop to explore how the Commission may support innovation, before setting the draft decision for DPP4.

[21] https://www.oriongroup.co.nz/corporate/corporate-publications/lincolnflexibilitytrial/

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[22])? 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.

23 Response:

The key principles proposed by the Commission are:

- additionality principle- project is riskier than the BAU solution
- risk allocation (and compensation)- risk should be allocated to suppliers or consumers based on who is best placed to manage them
- proportionate scrutiny- expenditure that would lead to material increases in price and/or a material change in quality of service should attract greater scrutiny
- incentives for efficient expenditure (where appropriate)- funding should face incentives to be used efficiently
- fits within the relatively low-cost DPP settings- complexity and cost aligned with low cost DPP regime

We submit that the principles proposed by the Commission for an innovation or non-traditional solutions incentive scheme are effective and we suggest further principles could be

- novel- funding would facilitate combination of new and/or existing ideas, data, technology or partners
- efficient- funding would facilitate prudent investment in systems and processes that improve asset management efficiency, customer service or information transparency.

The potential scheme design characteristics proposed by the Commission are:

- type and characteristics of expenditure
- approval timing: e.g., before or after project starts
- expenditure approved: forecast and/or actual
- share of expenditure approved (%)
- when and on what conditions (if any) approved expenditure is received
- maximum expenditure permissible ($ and/or %) across the period

[22] https://orionnz.sharepoint.com/:b:/r/sites/Consultations/Shared%20Documents/General/Consultations%20-%20active/Commerce%20Commission/DPP4%20Issues%20Paper/Default-price-quality-paths-for-electricity-distribution-businesses-from-1-April-2025-Issues-paper-

- supporting evidence
- penalty/reward mechanism.

We submit that the following scheme considerations covered by the design characteristics improve the innovation allowance design and will be more effective:

- broadening the definition of an innovative project to 'Innovative or non-traditional solution projects not otherwise provided for or incentivised' will increase the scope of projects that may qualify.
- ex-ante and forecast approval
- ex-post expenditure received
- proportionate scrutiny on size of project and the need for an independent report.

We submit that a further scheme consideration could be the extent to which collaboration (EDB to EDB or cross sector) is a feature of the innovation application.

Reliance on innovation allowances to fund flexibility allowances

We note that the IM Decision not to introduce use-it-or-lose it or contingent allowances. We also note the ridged step change criteria that requires a high level of forecast certainty for any new operating expenditure to ensure suppliers aren't rewarded or penalised for forecast errors.

EDBs will likely rely on innovation incentives to provide allowances to purchase flexibility services where these have not been forecast in the AMP. However, we believe that specific mechanisms will be needed to fund flexibility payments to reflect:

- innovation allowance processes will be too slow to respond
- baseline incentive mechanisms are unlikely to provide any value to suppliers using flexibility services because of the opex/capex substitution issue and the long development timeline for the service to be at the scale needed to defer traditional investment. Suppliers will need to pass on the full cost of payments to participate in flexibility services. This is likely to differ from other innovation projects where an EDB may see offsetting cost savings within a regulatory period.
- 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.
- a common exemption from including the non-performance of a flexibility service in a network's quality measures (i.e., exclude any SAIDI/SAIFI caused by the non-delivery of a flexibility service).

We also believe that funding flexibility payments from innovation or a targeted allowance should only be a temporary solution while flexibility services are developed. Correcting the opex/capex substitution issues will be the best long-term solution to avoid rewarding or penalising networks for forecast errors which would be unavoidable for difficult-to-forecast costs.

Flexibility payment innovation allowance

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

Design characteristics could include:

- Ex-post application to recover costs – part of the Compliance Statement Process
- Standardised calculation template for each application on an allowance, transactional evidence of payments
- Verification of evidence by auditors
- Maximum Limits applied to each network

Advantages

- EDBs not rewarded for forecast errors
- Regulatory certainty – EDBs confident to procure non-traditional services
- Light touch – well suited to DPP
- No additional Commission verification resource

Disadvantages

- Additional audit cost (somewhat mitigated by use of templates and calculators)
- Price volatility – although this could be limited by the maximum limit on total payments

Chapter 4 - Energy efficiency, demand-side management, and reduction of energy losses

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?

24 Response:

We submit that we do not agree with the Commission's initial view that a specific demand-side management and energy efficiency scheme is not required for DPP4.

EDBs and the Commission acknowledge the unprecedented tension in this DPP reset between price shocks for customers and undue financial hardship to Suppliers (EDBs) (and relevance of s 53P(8(a)), given the justified investment needs of EDBs. The treatment of opex within the regime currently disincentivises EDB's from leveraging cost efficiencies through demand side management and energy efficiency initiatives as envisaged by s 54Q.

The stronger the Commission's argument is for implementing alternate rates of change in s 53P(8) (to either minimise price shocks or address undue financial hardship) and we think they are strong at this reset, the stronger the justification is for implementing an energy efficiency and demand-side management scheme to ensure there are adequate incentives under s 54Q (and to be certain there are no disincentives). With the right balance, EDBs will reduce adverse price and quality impacts on consumers that would otherwise result from the regime including more direct avenues to address energy hardship. Alongside the emerging flexibility market, there are traditional and non-traditional methods of giving consumers control of their electricity use to lower their retail bill, reduce network peaks and subsequently reduce urgent and ongoing capex investment. That is clearly what section 54Q is seeking to achieve and is undoubtedly a least regrets policy approach. It is also hard to envisage any period of time where a scheme under s 54Q would be more justified or have more impact.

A well designed 54Q incentive that contemplates EDB involvement in energy efficiency of buildings, vehicles and appliances having the effect of maximising energy use, minimising energy loss and reducing customer costs as it pertains to electricity service is beneficial to the whole of system too.

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.

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.

During the IM review consultation, Unison[23] 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:*
>
> > *protect the s 52A outcomes (including limiting excessive profits); and*
> >
> > *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."*

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[24] is an investment towards demand-side solutions. The opex step change process disincentivises EDBs to invest in flexibility services over network capex where this is more cost beneficial (in fact could influence investment towards a potential capex solution which is easier to forecast).

In order to deliver on decarbonisation, incentivise flexibility services (in a joined up way with the Electricity Authority work programme) and meet its requirements under Section 54Q the Commission should, in the absence of a demand-side management and energy efficiency scheme, in the very least introduce a use-it-or-lose it fund for EDBs to access expenditure related to flexibility services and/or when that payment is to a particular aggregator the Commission should consider as a pass-through cost.

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

[24] Flexibility has been defined by the FlexForum Plan 1.0 as "The modification of generation and/or consumption patterns in response to an external signal, to provide a service within the energy system"

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?

25 Response:

Orion agrees with the Commission to not introduce a specific quality incentive scheme (QIS) related to reducing energy losses for DPP4. Orion continues to refine our methodology for determining loss factors going forward, and we expect the addition of smart meter data for network management will naturally drive improvements in this area of our business.

Chapter 5 – Setting revenue allowances

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.

26 Response:

The sector experienced a significant drop in revenues from DPP2 to DPP3 mainly due to the reduction in the WACC. The estimated WACC leading up to DPP4 appears to be returning to similar levels as DPP2 and the Commission will need to factor in this step change, in conjunction with increased expenditure levels, from supply constraints and inflation, experienced during DPP3 which partly inform BBAR as well.

Orion submits in agreement to initially setting the X factor to 0% for the DPP draft decision process. However, "the X-Factor affects the step change in revenue over the 5-year period, where an EDB requires to collect revenue for larger expenditure / compensation and to smooth the impact on prices to consumers" therefore if the step change in expenditure for DPP4 is such that it may result in material price shock at the start of the period then the Commission should look to change the X-Factor value to an appropriate level to accommodate price smoothing over the 5-year period.

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?

27 Response:

We submit in support of ENA's submission on this question.

We seek clarification that the IM decision to apply a revenue smoothing limit, that has not yet been specified, excludes the recoverable transmission cost.

Revenues for DPP3 dropped considerably, primarily due to the significant drop in WACC. With an expected uplift in WACC into DPP4 it can be expected that the real change may result in a higher-than-normal price increase for consumers. Inflation is impacting costs now, and because of the revenue cap and smoothing, revenues may not be recovered fully until later in DPP4 and potentially into DPP5. When applying a price shock analysis, the Commission should factor in:

- the need for sufficient cashflow for suppliers to ensure investment can be sustained
- smoothing too much will have a timing mismatch that will impact profitability
- for EDBs who regulatory hedge there is a full step change in interest cost on day one of the DPP. If revenue is capped interest coverage ratios will suffer.

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?

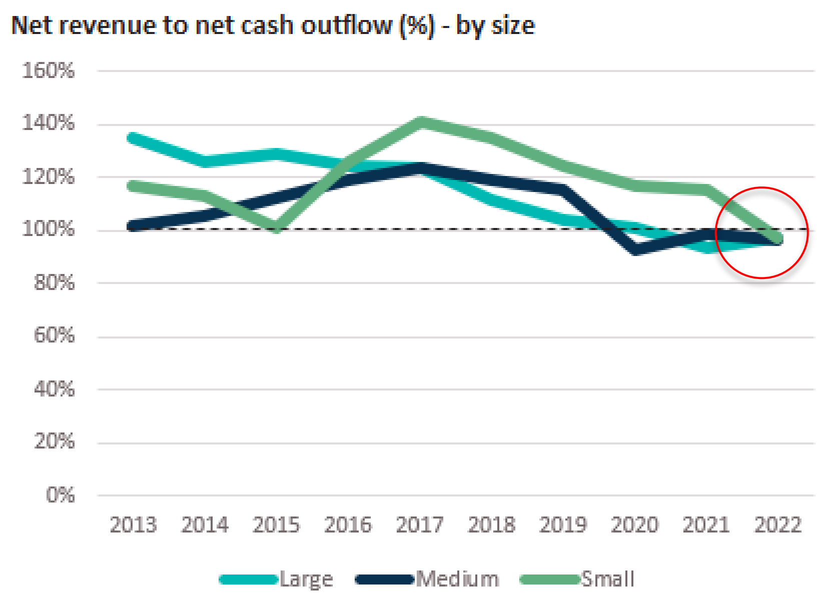
28 Response:

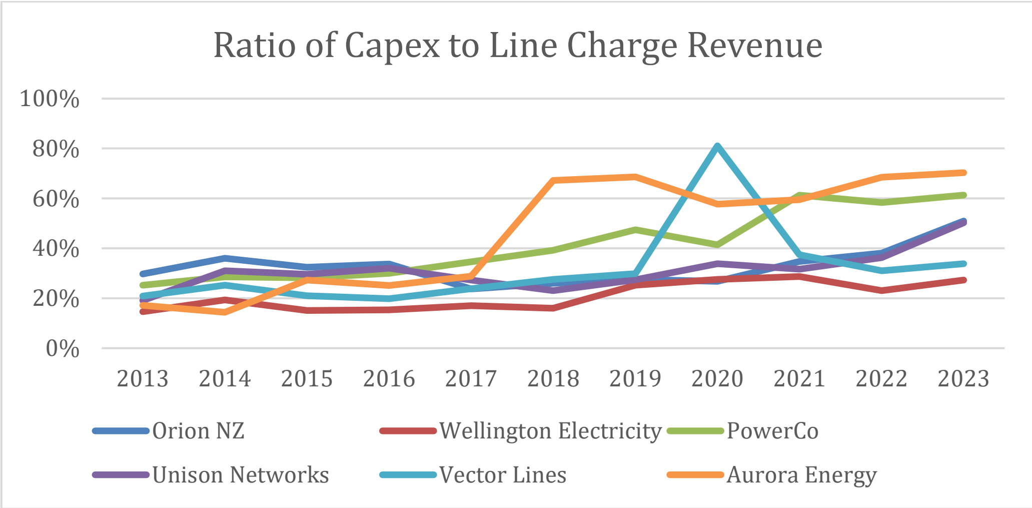
Orion submits that we have prudently reflected our region and customer's circumstances and required investment in our 2023 AMP, and refined further for our 2024 AMP, and that the forecast is in the long-term benefit of consumers. The Commission's DPP4 decision should allow appropriate allowances accordingly.

The use of a financeability assurance as part of the Commission's process should help ensure that financial hardship of the supplier is unlikely, as this would not be in the long-term interests of consumers.

Free cash is the binding constraint for EDBs, not gearing. The current trend of net cash outflows exceeding (or nearly exceeding) line charge revenue is unsustainable as illustrated by the diagram below showing this relationship by small, medium and large EDBs. Put another way we are needing to invest more in recent years, and moving forward, and the ratio of gross capex to line charge revenue would also indicate that we are needing to invest more than the revenue coming in (see further graph below).

We believe it is realistic to expect an uplift in allowances to support investment thereby ensuring an appropriate balance between investment and revenues.





The Commission needs to ensure that the revenue wash-up balances which have accumulated during DPP3 are recoverable by EDBs going forward. We have noticed, that mainly due to high CPI during DPP3 and capping EDBs revenue, there is an accumulation of balances in the washup accounts. If this continues, EDBs will not be able to recover these balances during DPP4 and the recovery will extend well beyond 2030.

Chapter 5 – Consumer bill impacts

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?

29 Response:

We have no specific view on this beyond those set out in the ENA submission .