12 July 2024

EDB DPP4 Draft Decision
Commerce Commission
Via email:infrastructure.regulation@comcom.govt.nz

Tēnā koutou

The DPP4 decision is a crucial enabler for South Canterbury to electrify at pace

Alpine Energy currently supplies over 34,000 homes and businesses in South Canterbury. The region is a significant contributor to Aotearoa New Zealand's success, especially through primary exports and tourism. We therefore expect significant change to the region's electricity needs through growth, electrification, and decarbonisation. Alpine is investing in our capabilities and collaborating closely with our peers, customers and stakeholders to support the needs of this diverse region.

The DPP4 decision and its application to 2030 will have long-lasting impacts on our customers and community. At the heart of our business is a core belief: electricity is an essential service that empowers our communities. It will influence how we maintain reliable electricity supply, support South Canterbury's decarbonisation and electrification efforts, and drive for efficient outcomes that support an affordable network.

Our summary views on the draft decision are:

- **We support the draft decision**. There are opportunities to refine (both practical and technical) some components of the decision so it can align with customer outcomes.
- **Ensure revenue smoothing mechanisms are future proofed**. We think EDBs are in the best position to manage the complexities of revenue changes and price setting. And EDBs have the incentive and tools to do this well.
- **Ensure all parties have clarity about the reopener process**, as it will help customers, distributors, and the Commission deliver market-like outcomes.
- **Retain step-changes to operational expenditure** and revise the approach. These step changes reflect necessary cost changes EDBs are experiencing.
- **Raise the capital expenditure cap to 130%** of historical capex. We share the Commission's concern that putting off investment can lead to higher costs later. EDBs can manage any price impacts directly via price setting and revenue smoothing.

Our submission material is attached and comprises two parts: deeper discussion on key topics (Appendix A) and commentary on each draft decision (Appendix B).

We appreciate the effort and engagement from Commission staff throughout the consultation process and look forward to the next steps in this process. Please contact [redacted] regarding this submission.

Yours sincerely,

[redacted]

Caroline Ovenstone
Chief Executive Officer

Appendix A – Discussion

1. This Appendix contains discussion about areas of the Draft Decision we think can be improved.

Revenue smoothing – simplify and future-proof the approach

2. The regulatory regime includes several mechanisms that affect the level of annual revenue that can be recovered through pricing in each year, and across years. Distributors have the more complex task of setting prices across customer groups which capture the nuances of those groups at a more granular level. This includes smoothing the impacts of annual prices changes on customers.

3. Looking ahead to 2030 and beyond, distributors will be facing a range of situations which can affect annual revenue and limit the ability for distributors to manage revenue smoothing over the long-term, for example:

    a. using pricing for investment signals

    b. removal of the constraint around Low-Fixed charge regulations

    c. revenue adjustments for re-openers

    d. adjustments for innovation projects (INTSA regime)

4. All possible combinations of these scenarios will be difficult to explore prior to the final DPP4 Determination. Setting limits ahead of time therefore needs either high confidence they will not bind unintentionally, or 'release valve' options to deal with exceptions when they do. This is the context for our views.

5. The Draft Decision (R1.3) allows EDBs to voluntarily defer up to 10% of their forecast allowable revenue each year. For the reasons noted above we:

    a. support increasing or removing this limit. ENA's submission notes there is no economic reason for voluntary under-recovery to be capped. The case of an increase is that Commission has determined that 20% movement in prices is acceptable, this should be applied to both upward and downward price movements.

    b. suggest that if unilaterally altering the rates is unappealing that an 'on application' exemption process be considered. This would create additional administrative overhead for all parties, which is a direct result of setting a limit.

6. On a technical note, ENA's submission has noted a change to the IMs (para 3.14) is needed to make the proposed mechanism workable. We support this practical change and see it as non-controversial.

7. Making IM changes of this nature would align with the Commission's approach to other IM changes of this nature[1]. Some of the linkages between the Input Methodologies and DPP4 determination are complex, new, and untested. We anticipate further tweaks will be needed as the regime is used in practice and support work to expedite them.

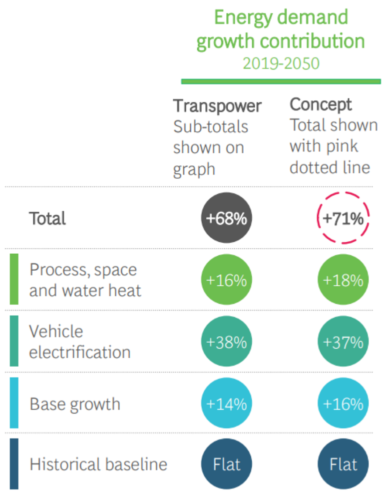
8. **We recommend** the Commission target making appropriate IM amendments prior to publishing the DPP4 determination to ensure regulatory clarity.

9. **We recommend** the Commission engage with EDBs and interested stakeholders on how these mechanisms work in practice and update the guidance material (if appropriate)

Price path – review approach to setting initial prices

10. The Draft Decision (P4) proposes that price shocks are assessed on real terms, per ICP, and include wash-ups and IRIS impacts. This flows through to the setting of the price path.

11. Our preference is that limits on initial prices are minimised or set higher and EDBs be tasked with managing the impact. This is because it is the price-setting process which ultimately affects customer impacts, and the EDB is responsible for communicating the reasons to customers. As noted above, revenue smoothing within the regulatory period is complex and EDBs are experienced at managing this now, given the experience with DPP3.



Observation: Future energy demand differs from 'base growth'. Price impacts will be tailored and targeted to specific customer groups. Source: "The Future is Electric".

12. With DPP3, EDBs consider year-on-year impacts on customers as part of a broader decision-making process. Prices are tailored to the customer-base, pricing methodology, network characteristics, and within-period impacts which can be significant. The Commission's assumptions in setting and smoothing initial prices (revenues) naturally doesn't consider this detail. Nor does it consider the on-going forecasts, which is projected to differ significantly from historical growth, as illustrated in "The Future is Electric"[2].

13. Should limits be applied in the final decision, we think the approach for setting initial price levels could be improved. While we support this approach in

[1] https://comcom.govt.nz/__data/assets/pdf_file/0022/357205/Notice-of-Intention-Potential-amendments-to-input-methodologies-for-electricity-distribution-services-2-July-2024.pdf

[2] https://www.bcg.com/publications/2022/climate-change-in-new-zealand

principle, we do not agree that ICP increases alone should be used as a proxy for demand growth (4.51.3).

a. A proxy is not required in this case. AMP disclosures (Schedule 12c(iii)) provide forecasts for demand growth – maximum coincident system demand growth (MW) and electricity volume growth (GWh).

b. This will provide a more nuanced forecast for growth that better reflects the impact of increased use and reliance on electricity by households and businesses, while also capturing ICP growth.

14. If the Commission is to limit P0 changes, we agree with ENA's view that that this should be applied symmetrically to future determinations regardless of whether they result in revenue increases or decreases. We suggest.

15. **We recommend** the Commission review whether the DPP4 revenue smoothing settings achieve the outcome intended

Lift capital expenditure allowances

16. Customers on Alpine's network are in a period of transformation. We are forecasting 'when not if' load growth driven by industrial expansion (now using electrified heat and production) and decarbonisation of existing loads. We have highlighted this in prior submissions to the Commission[3] and our public documents.

17. The Draft Decision allows for 68% of our 2024 AMP capex forecasts. This effectively amounts to our asset renewal and replacement (**ARR**) and asset relocation and reliability, safety, and environment work programmes across the DPP period. Rather than planning and delivering this work, we will need to explore other options to finance and deliver forecast system growth (**SG**) projects, required to meet customer demand.

18. We have forecast large SG projects at industrial areas on our network and following close engagement with customers over the past two years, we have a high degree of certainty that our investments will be required in this regulatory period. Deferring this critical investment will negatively impact our customers' ability to meet their own growth needs.

19. We agree with ENA's submission that the move the 125% capex cap is an improvement for DPP4, but also agree that raising this cap to 130% would be more enabling for EDBs facing significant step changes, while still limiting price impacts (which EDBs can partly manage). Avoiding costly, and resource and time consuming CPP and reopener processes with a more appropriate capex cap is ultimately in the long-term interests of our customers. Price impacts can be managed by EDBs, both within period (who pays what) and also across

[3] For example, our submission on the capex framework https://comcom.govt.nz/__data/assets/pdf_file/0029/347492/Alpine-Energy-Ltd-11-March-2024.pdf

periods (using revenue smoothing). This is a better mechanism for managing price impacts than the level of investment cap.

20. **We recommend** the Commission amend decision C2 and set the capex allowance in constant dollars based on the lower of an EDB's total forecast capex or 130% of its historical reference period capex.

Deliverability depends on the portfolio of work rather than the total cost

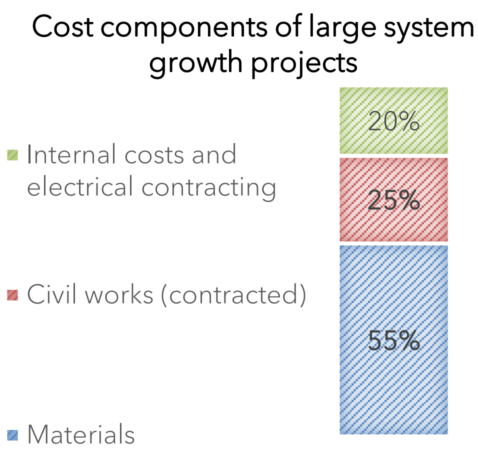
21. The Commission has queried the deliverability of EDB capex forecasts, including the feasibility of large increases ramping up over a relatively short time frame, and the uncertainty of growth projects (B7).

22. Like all other EDBs, we are aware of the challenges we face in both attracting and retaining talent and are working across our business, and with industry partners to resolve this, build capacity, and identify delivery efficiencies.

23. We are confident we can deliver our planned work programme as set out in our 2024 AMP. Our delivery capacity has grown significantly over DPP3, delivering our increased capex work programme year-on-year.

24. One of the reasons for our confidence is that the relationship between capex growth and work is not linear, particularly across different expenditure categories. A 40% increase in capex does not require a 40% increase in work for an EDB or electrical contracting services.

    a. During the DPP4 period, we have planned two new substations, two new switching stations, and a programme of new sub transmission cable installations to support industrial customer growth and decarbonisation. Large projects like these have elevated material and civil contractor costs (compared, for example, to ARR project costs) and do not need an equally substantial increase in labour hours for EDBs and electrical contracting services.



Observation: 80% of large project costs are outsourced from the EDB

    b. The cost base of large system growth projects is substantially driven by materials and outsourced civil work (see chart).

    c. Overhead and underground maintenance projects recently completed averaged 45% materials and contracting, with 55% internal/electrical contracting.

25. **We recommend** the Commission acknowledge the non-linear relationship between forecast system growth capex and capacity requirements and ensure any impacts about deliverability on DPP4 settings (eg capex limits) are evidence-based.

Revise approach to operating expenditure step changes

26. We support the Commission's draft decision to approve step changes to opex (O2.1-O3.7). Networks are exposed to new activities and associated costs eg cyber security, for which a step change is an appropriate mechanism for addressing rather than a re-opener.
27. Our view is:
    a. the proposed cost categories and associated costs are for important and essential business activity – akin to necessary investment to provide a reliable network
    b. There is no incentive to overstate the costs. If this is considered a risk, it could be alleviated by proportionate scrutiny/accountability along with simple reporting.
28. By not approving these costs, there is either a direct IRIS impact (solely due to the regulatory regime, and not reflecting an efficiency gain or loss) or an implicit requirement to deprioritise other business activity. Neither is good for customers in the long term.
29. In the draft decision a 5% cap has been applied to aggregate operating expenditure (opex) step changes as an alternative to in-depth scrutiny of individual data provided by EDBs. The approach potentially aligns with the Commission's commitment to a low-cost DPP regime. Low-cost doesn't have to mean overly simplistic.
30. We think there are alternatives (some of which can be combined) which align with the low-cost principle. For example:
    a. Approve step-changes where increased expenditure forecasts are supported with documentation (our preference). Require reporting on each cost category towards the end of DPP4 (similar to quality standards) to inform the approach for DPP5.
    b. Apply a cap (eg 5%) a subset of non-critical costs, approving remaining 'critical' or 'necessary' costs. For example, cyber security costs could be considered 'necessary' and therefore be excluded from the capping mechanism given the direct link to network security and resilience, and link to other forecasts eg SaaS.
    c. Apply a 5% cap at an individual level rather than aggregate (ENA proposal).

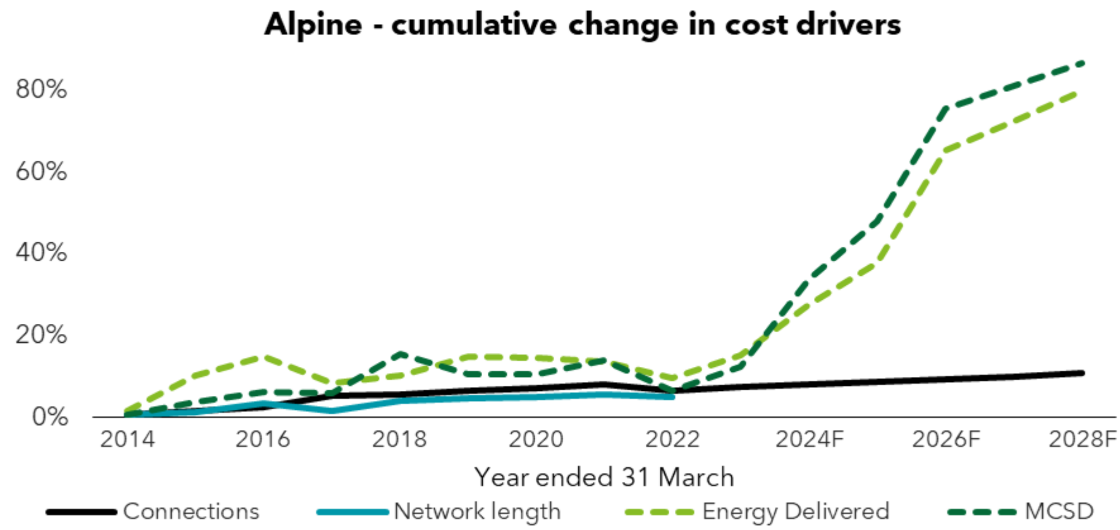
31. We look forward to seeing the options and approach from submitters on this topic. We are particularly interested to hear views on which of the proposed step change categories are considered unnecessary.

32. **We recommend** the Commission review its approach to step changes to opex.

Consider network demand as a scale factor for opex trend factors

33. The Draft Decision (O5.3) retained the DPP3 approach to scale factors for network opex: ICP count and line length. Network demand was not considered as an additional scale factor. We think it should be.

34. Our submission to the Commission on opex discussed the growth in energy delivered and the maximum coincident system demand (**MCSD**) has outstripped that of connections and network length since 2014. Our projected growth in energy delivered and MCSD is significantly higher than that of connections.



Source: EDB Performance Data, AMP 2024

35. For regional EDBs outside of the main cities, ICPs and line length will remain mostly unchanged due to the nature of the networks[4]. However, due to increased demand from customers to achieve their decarbonisation and electrification goals, the MCSD will increase significantly. We signalled this in our 2023 and 2024 AMP's and in previous submissions to the Commission.

36. This information is readily available to the Commission. AMP disclosure Schedule 12c(iii) contains forecasts for demand growth – maximum coincident system demand growth (MW) and electricity volume growth (GWh).

37. We expect other EDBs will also face changes to the patterns of project peak demand and ICP growth due to the composition of their networks eg urban-

[4] This is because the total line length is dominated by many long feeders. New ICPs will typically have short connection lengths.

dominated EDBs may see peak demand driven by private and public EVs that is vastly different to their history and other EDBs. Some EDBs may be more naturally home to data centres vs others will not[5]. These factors can be expected drive a step change to the historical ICP/MW link and are expected over the next 5-10 years.

38. **We recommend** the Commission include the increase in network demand as an additional cost driver for network opex.

Provide more guidance on the reopener processes

39. Alpine's capex allowance under the draft DPP4 decision is 68% of 2024 AMP forecasts for the period. On this basis, we expect to apply for reopeners to deliver some significant components of our work programme. We are therefore highly focussed on the mechanics of the application process, particularly where we are aligning asset management priorities, multi-customer plans, and the regulatory regime. Our objective is that the outcome for customers is not unduly impacted by the regulatory regime.

40. Equally, as our customers make significant growth and decarbonisation decisions, they require timely information on capacity availability. We are engaging with customers about this now. Their decisions are significant for both the region, and the country. Our collective role is to enable them.

41. Customers are asking us about what the business case looks like and how fast we can respond. We are confident about the asset delivery timeframes and are seeking similar clarity about the regulatory process that marries with it. It is essential that we can clearly, confidently, and collectively explain, how and when a reopener process will enable customer connections. We're keen to help the Commission with this.

A recent customer forum at Alpine Energy with commercial customers explaining current state and collaboration needed to meet future needs at pace, July 2024

42. The Draft Decision provides some commentary about some of the mechanics, especially where capex allowances are below forecast. For example:

    a. "EDBs who have a capex allowance which is below their AMP forecast, who consider they may need to apply for reopeners, will need to create a

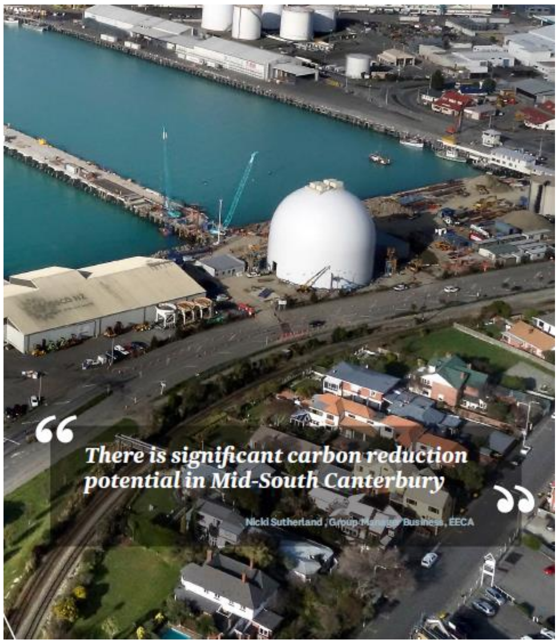
[5] For example, Auckland (Vector network) has 40 MW of data centres connected and a much larger connection pipeline (source, Vector 2024 AMP). Alpine's network has none.

prioritised list of projects and programmes which would outline how they intend to spend their capex allowances during the period" (B258)

b. prioritised lists "will be required to enable the assessment of the reopener applications."

43. We support the principle around prioritisation as it underpins asset management and forecasts. We are signalling in this submission that there is a high value in regulatory clarity about how this sort of information could be used for initial and successive applications. Asset project and programme priorities and plans can evolve through a price-path period compared to the AMP upon which the price path was set (the what, when, and how much). We encourage the Commission to provide more clarity here eg via the final Determination or a separate guidance material. It will be helpful to understand the link to IM's about "reviewing and reprioritising expenditure" clause 4.5.13(1)(c)(iii).

44. Two comments from the Mid-South Canterbury Regional Energy Transition Accelerator (RETA) report[6] support the significance and value from collectively delivering a well-functioning re-opener process. On the topic of recommended roles of EDBs:



"…we recognise that the regulatory framework for network companies may not support pragmatic, sensible investment decisions. While we have not investigated the potential for regulatory change, we endorse change if it helps accelerate decarbonisation…" (p145)

"A clear process, timeframes and information required for obtaining network connection. These processes should have realistic timeframes and the nature of the information that each stage of the process will provide the process heat user, and the data and information network companies need from the process heat user at each stage" (p145)

45. These are universal observations. Clarity from the Commission on the reopener process will support us collectively deliver this outcome for customers.

46. **We recommend** the Commission develop documentation and guidance on reopener processes (eg nature and timing of evidence, indicative timeframes,

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

indicative assessment criteria, and a fast-track process[7]). There may be some opportunities for CPPs here too.

47. **We recommend** the Commission provide clarity and explicit guidance on how these priority listings will be assessed and used in reopener applications, and when EDBs would prepare these lists, and how existing mechanisms are used to support this (e.g., at the time of reopener application, prior to DPP4, or at another time).

Opportunities to streamline reporting

48. We support the intent behind the Commission's consideration of additional reporting requirements, particularly Annual Delivery Reports (ADRs). Providing stakeholders with a greater understanding and transparency over our work is central to providing confidence in the sector. We have two reflections:

    a. We suggest ADRs are prioritised in the Commission's Targeted Information Disclosure Review programme. This would give to give stakeholders time to engage with the Commission to develop an effective delivery reporting framework which provides value to consumers, the Commission, and EDBs, without unnecessary duplication.

    b. One area which could be streamlined is pricing. There are opportunities for the Commission to reduce the complexity of the disclosure framework and better align with the Electricity Authority's work programme.

49. **We recommend** that the Commission address additional reporting requirements through separate consultation processes, specifically the Commission's TIDR.

50. **We recommend** that, as the Commission considers additional reporting requirements for EDBs, this is balanced by equal attention paid to opportunities to remove redundant and low-value reporting requirements.

Alpine Energy's restatement of historical Information Disclosure Schedules and the impact on DPP4

51. In 2023 Alpine Energy discovered historical errors in its Information Disclosure statements. This administrative error resulted in the setting of revenues higher than they should have been in 2015-23, leading to non-deliberate over-charging of the lines charges.

52. There are two comments in the Reasons Paper we'd like to have corrected should they flow through to the final Determination.

    a. The Reasons Paper (in Appendix I, paragraph 18) includes the comment: "On 6 October 2023, Alpine Energy redisclosed its ID data for the years

[7] See para 45-46, https://comcom.govt.nz/__data/assets/pdf_file/0011/323102/Alpine-Energy-Ltd-Submission-on-IM-Review-2023-Draft-Decisions-19-July-2023.pdf

between 2013 and 2023 to correct for an error in the calculation of depreciation." Alpine Energy redisclosed the restated Information Disclosure Schedules for 2014 to 2022 on 30 November 2023. This was pursuant to the ID exemption granted to us by the Commission, dated 30 August 2023[8].

b. Footnote 575 on page 378 includes the comment "… Alpine has disclosed that they were non-compliant with the revenue path over DPP3." The correction of errors in the Information Disclosures Schedules for the years ended 31 March 2014 – 31 March 2022 does not indicate non-compliance with the DPP3 price-quality path. We did not disclose that we were non-compliant with the revenue path.

53. It's important the commentary about the error and its impacts are correct given the investigation is mid-flight and the issue is significant to us, our customers, and our stakeholders. We are happy to assist the Commission with reviewing Alpine-specific statements in the Final Determination prior to its release.

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[8] https://comcom.govt.nz/__data/assets/pdf_file/0025/328831/Electricity-Distribution-ID-Exemption-Alpine-Energy-Limited-Extension-to-the-deadlines-for-year-ending-disclosures-30-August-2023.pdf

Appendix B –Responses to Draft Decisions

Request for feedback on DPP4 draft decisions

Capital expenditure (Capex)

1. **Capex**

C1	Use EDB 2024 AMP forecasts as the starting point for setting capex allowances.
C2	Set the capex allowance in constant dollars based on the lower of an EDB's total forecast capex or 125% of its historical reference period capex, with an adjustment for forecast capital contributions.
C3	Use a five-year historical reference period for setting capex allowances [2019 to 2023 for the draft and 2020 to 2024 for the final determination] with an additional cost escalation adjustment.
C4	Include an allowance for the cost of financing, scaled in proportion to the capex allowance.
C5	Include an allowance for the value of considerations for vested assets and spur assets equal to 2024 AMP forecasts.
C6	Use the All-Groups CGPI forecast with an additional adjustment to escalate the constant price capex allowance to a nominal allowance.

Views/Response:

Support draft decisions C1, C4, C5 and C6.

Support the increase in the capex allowance provided by draft decision C2, and recommend a 130% increase. See discussion in Appendix A. This is to further enable EDBs to deliver on work programmes to meet customer demand from growth and decarbonisation and provide resilient networks for all customers. On the margin, a 130% increase can reduce or defer reopener applications.

Support with the use of a five-year historical reference period (C3) nothing that historical and future lumpy investment (whether planned or re-openers) will not be well reflected in this approach. This is symmetric issue affecting forecasts which are above, or below, historical averages.

Operating expenditure (OPEX)

2. **Opex**

O1.1	Apply a base-step-trend approach to forecasting opex.
O1.2	Use 2024 as the base year. [2024 AMP forecasts used for the draft decision]

Views/Response:

Accept draft decision O1.1. Our preference is for AMPs be used for opex forecasting. However, in line with the submission from ENA, we accept the base-step-trend approach as an appropriate alternative.

Support draft decision O1.2 to use 2024 Information Disclosure data as the base year.

Request for feedback on DPP4 draft decisions

3. Opex step changes

O2.1	Consider proposed step-changes against a defined set of factors, incorporating judgement.
O2.2	Step-changes should be significant.
O2.3	Step-changes should be adequately justified with reasonable evidence in the circumstances.
O2.4	Step-changes must not be included elsewhere in expenditure allowances.
O2.5	Step-changes should have a driver outside the control of a prudent and efficient supplier.
O2.6	Step-changes should be widely applicable.
O3.1	Include a step-change to reflect increasing insurance costs.
O3.2	Include a step-change for greater consumer engagement.
O3.3	Include a step-change for low voltage (LV) monitoring and smart meter data.
O3.4	Include a step-change for increasing cyber-security costs.
O3.5	Include a step-change for the costs of software-as-a-service (SaaS).
O3.6	Include a negative step-change in Aurora's indicative forecasts to capture the end of its CPP spend.
O3.7	Cap aggregate step-changes (in real terms) at 5% of trended opex excluding step-changes.

Views/Response:

Support all draft decisions relating to opex step changes, except for O3.1

Recommend an alternative for the draft decision O3.1 to be amended. In line with ENA, we believe insurance cost will be more dealt with via a pass-through mechanism or an independent cost escalator.

Recommend an alternative for draft decision O3.7 we have provided our views, and options in Appendix A.

Request for feedback on DPP4 draft decisions

4. Opex trend factors

O4.1	Escalate all opex costs using the same cost escalator.
O4.2	Escalate opex using the all-industries labour cost (60% weighting) and a producers' price (40%) indices, plus a 0.3% uplift to reflect EDB-specific inflation.
O5.1	Scale growth forecast separately for network and non-network opex.
O5.2	Use 2018-2024 as the reference period for scale elasticities and driver projections [2024 data available post-draft].
O5.3	Forecast network opex scale growth with line length (elasticity 0.52) and ICPs (0.45).
O5.4	Forecast non-network opex scale growth with line length (elasticity 0.35), ICPs (0.22), capex (0.30).
O5.5	Forecast lines length extrapolated using recent growth rate trend, and irregular data adjusted.
O5.6	Forecast ICP count extrapolated using recent growth rate trend, and irregular data adjusted.
O5.7	Forecast capex based on a constant growth.
O6.1	Apply an opex partial productivity factor of 0%.

Views/Response:

Support draft decision O4.1, but would prefer a separate cost escalator for insurance

Support draft decisions O4.2, O5.1, O5.2, and O5.4 – O5.7

Do not support O5.3: See Appendix A for discussion.

Support draft decision O6.1 to retain an OPEX partial productivity factor of 0%.

Innovation and section 54Q incentives

5. Innovation, energy efficiency and demand-side management

U1	Introduce an Innovation and Non-traditional Solutions Allowance (INTSA), capped at 0.6%.
U2	Incentivise energy efficiency and demand-side management incentives through the INTSA.
U3	Do not introduce a reduction of energy losses incentive.

Request for feedback on DPP4 draft decisions

Views/Response:

Support draft decisions U1 – U3. We believe the Commission's approach to innovation in DPP4 is a significant improvement on DPP3. We think the INTSA should be reviewed to ensure collective EDB initiatives can be included. This could be supported by a higher INTSA allowance to facilitate participation. For example, Alpine Energy is participating with a few other EDBs in a prototyping exercise for a local flexibility market. We expect ENA's Future Network Forum will have projects of a similar nature. There will be customer and wider benefit if the drafting of the INTSA requirements can encompass these sorts of scenarios.

Support the response and recommendations provided by ENA.

Quality

6. Quality standards

QS1	Maintain separate standards for planned and unplanned SAIDI and SAIFI.
QS2	Retain annual unplanned reliability standards for SAIDI and SAIFI.
QS3	Retain the 2.0 standard deviation buffer for setting the unplanned interruptions reliability standards.
QS4	Maintain regulatory period length standard for planned SAIDI and SAIFI.
QS5	Change the planned reliability buffer for the planned interruptions reliability standard to be a 100% uplift on the historic average, capped at a +/- 10% movement from the current standard.
QS6	De-weight the impact of notified planned interruptions by 50% in the assessment of compliance with planned interruption standards.
QS7	Retain SAIDI extreme event standard set at 120 SAIDI minutes or 6,000,000 customer minutes where specified.
QS8	Retain enhanced automatic reporting following a breach of a quality standard.
QS9	No new quality measures are introduced as part of the quality standards applying in DPP4.
QS10	Set interruptions quality standards and incentives for Aurora transitioning from a CPP to the DPP on the same basis as for other EDBs on the DPP.
QS11	Retain the requirement for reasonable reallocation of SAIDI and SAIFI following an asset transfer between EDBs.

Views/Response:

Support all draft decisions relating to quality standards, except for QS5. Our preference is for the current approach to be retained.

Support the response and recommendations provided by ENA regarding the planned reliability buffer.

Request for feedback on DPP4 draft decisions

7. Quality incentives

QIS1	Retain the revenue-linked quality incentive scheme for planned and unplanned SAIDI. SAIFI is excluded.
QIS2	Unplanned incentive rates are informed by the value of lost load (VOLL), discounted by (1-IRIS retention factor) to reflect expenditure incentives, and a further 10% to reflect quality standard incentives, with VOLL set at $35,374r/MWh.
QIS3	Planned incentive rates are reduced by 35% relative to the unplanned incentive rate.
QIS4	Planned 'notified' interruptions are reduced by 75% relative to the unplanned incentive rate to reflect less inconvenience to consumers.
QIS5	Incentives are revenue-neutral at the average of the reference period, also known as the target.
QIS6	The SAIDI caps (which determine maximum losses) are set equal to the SAIDI limits for planned and unplanned SAIDI.
QIS7	The SAIDI collars (which determine maximum gains) are set at 0 for unplanned and planned SAIDI.
QIS8	Cap revenue at risk at 2% of actual net allowable revenue.
QIS9	Do not implement any new incentive schemes.
QIS10	Do not make an explicit adjustment to match the duration of retention benefits between EDBs and consumers.

Views/Response:

Support draft decisions relating to quality incentives.

Support the recommendation provided by ENA that the Commission review the de-weightings used for notified outages.

8. Normalisation

N1	Normalisation only applies to unplanned interruptions, which are the only initiators of a major event day.
N2	Retain the normalisation approach used in DPP3, being: - define a major event as 24-hour rolling periods (assessed in 30-minute blocks) - the major event boundary value has been identified as the 1104th highest rolling 24-hour period for SAIDI and SAIFI over the 10-year reference period - normalisation is applied on half-hour blocks, within a major event, where the SAIDI figure exceeds 1/48th of the boundary value, and - treat major events by replacing any half-hour that is greater than 1/48th of the boundary value with 1/48th of the boundary value if that half-hour is part of the major event (can exceed 24 hours in duration).
N3	SAIDI and SAIFI major events are triggered independently.
N4	Set a higher boundary for very small EDBs.
N5	Retain additional reporting by EDBs for each unplanned major event in its compliance statement consistent with DPP3.

Request for feedback on DPP4 draft decisions
Views/Response: **Support** draft decisions N1 – N5 regarding normalisation.

9. Reference period

RP1	Use a 10-year reference period from 1 April 2013 to 31 March 2023 to inform the parameters for unplanned interruptions reliability standards and incentives, with the period adjusted to 1 April 2014 to 31 March 2024 for the final determination.
RP2	Apply a reference period for planned interruptions of 2017 – 2023 for the draft decision, extended to 2017 – 2024 for the final decision.
RP3	Retain the cap on inter-period movement, ±5% for unplanned interruptions for both the SAIDI and SAIFI unplanned target and also apply this to the SAIDI and SAIFI unplanned limits.
RP4	Make no explicit step changes to reliability targets or incentives.
RP5	Make no explicit adjustments for instances of non-compliance contained within the unplanned interruption reference period dataset.
RP6	EDBs must record successive interruptions on the same basis they employed in responding to the s 53ZD notice.
RP7	Interruptions directly associated with an approved INTSA project are excluded for calculation of SAIDI and SAIFI values up to a cap of 0.5% of the respective SAIDI and SAIFI limit.

Views/ Response:

Support draft decisions RP1 - RP7 regarding the reference period of interruptions.

Revenue path

10. Price path

P1	Set starting prices based on the current and projected profitability of each supplier using a building blocks allowable revenue (BBAR) model.
P2	Set a default rate of change relative to CPI (X-factor) of 0%.
P3	Set alternative X-factors such that, in most cases, initial price shock is limited to 20% in real per ICP. terms, and the change between years within the regulatory period to 10% (based on the price shock and notional financeability assessments).
P4	Assess price shocks on a real revenue per ICP basis, incorporating wash-ups and IRIS.
P5	Assess notional financeability using FFO/Debt and Debt/EBITDA ratios.

Request for feedback on DPP4 draft decisions
Views/Response: **Support** draft decisions P1 – P5 regarding the price path. **Do not support** draft decision P3. We think there's a better approach than using ICP increases as a proxy for demand growth (4.51.3). See Appendix A for discussion. **Support** P5 and the additional information included in the draft decision on how the Commission will apply the financeability "sense-check". We support the decision to draw on metrics from Standard & Poor's methodology as this is a transparent, practical and reasonable approach.

11. IRIS

I1	IRIS retention rate for capex is equivalent to the opex rate.
I2	Determine IRIS opex and capex forecasts in real terms (inflated by CPI).

Views/Response:

Support draft decisions I1 and I2 regarding the IRIS

Support ENA's recommendation that customer connections capex be excluded from IRIS.

12. Revenue Path

R1.1	Apply a revenue cap with wash-up as the form of control.
R1.2	Forecast CPI based on the four-quarter average change in CPI between the first year of the regulatory period and the current year.
R1.3	Apply a 90% "voluntary undercharging" limit (or an alternative in some cases).
R1.4	Include a large connection contract (LCC) wash-up term in the wash-up accrual formula, to avoid recovery of LCC revenue from other customers.
R1.5	Allow distributors to agree a reasonable reallocation of revenue following an asset transfer.
R2.1	Apply the revenue smoothing limit based on forecast net allowable revenue for the current year and CPI-adjusted recoverable costs from the prior year.
R2.2	Apply a revenue smoothing limit of 10%.
R3.1	Implement the revenue wash-up by specifying a re-run of the DPP4 financial model.
R3.2	Calculate the Y1 inflation wash-up based on the four-quarter average change in inflation between Y0 and Y1.
R3.3	Do not specify base revenue wash-up draw down amounts for DPP4.
R3.4	Calculate the time-value of money of the opening wash-up balance using one year of the DPP3 WACC and one year of a blended DPP3/DPP4 WACC (for a value of 5.25%). [This will be updated for the final decision.]

Request for feedback on DPP4 draft decisions

Views/ Response:

Support draft decision R1.1 regarding the retention of a revenue cap with wash-up as the form of control. As proven through DPP3, the wash-up mechanism ensures that EDBs are kept whole in times of increasing uncertainty. See Appendix A for our comments on revenue smoothing, undercharging.

Do not support draft decision R1.3 regarding a 90% "voluntary undercharging" limit. See Appendix A for our comments on this.

13. Other Matters

X1	Retain the current five-year regulatory period length.
X2	Include Aurora in the DPP4 expenditure and revenue setting process.
X3	Retain the CPP application timings set for DPP3.

Views/Response:

Support draft decision X1 to retain a 5-year regulatory period to ensure a low-cost DPP regime and allows changes in economic conditions to be mitigated. A shorter length may have merit in the future as a mitigant for forecasting or future uncertainties that can't be easily addressed through the regime.

Support in principle the draft decision X3 to retain CPP application timings. An approach which accounts for the differing application complexities will be in the interests of consumers, applicants, and the Commission.

14. Other inputs to the financial model

M1	Weighted average cost of capital (WACC) of 7.37%. [This will be updated for the final decision.]
M2	Include an allowance for disposed assets, based on historical levels.
M3	Forecast depreciation on existing assets based on information provided by each EDB.
M4	Use base year data from 2024 Information Disclosures in our final decisions, and data from 2023 Information Disclosures for our draft decisions.
M5	For CPI forecasts, use the most recently available RBNZ MPS forecasts from when the WACC was determined.

Views/Response:

Support in principle draft decisions M1 – M5 regarding other inputs to the financial model.

Support ENA's submission recommending the Commission replace the arbitrary 44-year useful life for assets with each EDB's weighted average useful life of commissioned assets over the current regulatory period.

Support ENA's submission regarding the impact of the IMs' approach to the WACC.