Aurora Energy's submission

Default price-quality paths for electricity distribution businesses from 1 April 2025 – Draft decision

12 July 2024

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1. Introduction

1. Aurora Energy Limited (Aurora Energy) welcomes the opportunity to submit its views on the Commerce Commission's (the Commission's) Default price-quality paths for electricity distribution businesses from 1 April 2025 – Draft decision.
2. Section 2 of this document provides a summary of the key aspects of Aurora Energy's feedback, with our responses to the Commission's specific questions provided in section 3.
3. No part of our submission is confidential.

2. Executive Summary

Operating expenditure

4. We accept the Commission's continued use of the base-step-trend approach to determine operating expenditure (opex) for the DPP4 period is appropriate, provided that appropriate step changes are allowed, and no other adjustments are made to the base year.

   Aurora Energy's opex allowances must use RY25 actual opex as the starting point.

5. We thank the Commission for including Aurora Energy in the draft decision paper and appreciate the work that has been undertaken to provide indicative DPP4 allowances. However, to ensure consistency with the base-step-trend approach to opex forecasting, the Commission must use Aurora Energy's actual expenditure for RY25 as the starting point for setting our DPP4 allowances.
6. The rationale for making a $3.5m base year adjustment to Aurora Energy's opex forecast is not appropriate for the following reasons:
   - The draft decision states "a $3.5m reduction in opex is justified to avoid one-off CPP costs being locked in for future periods." However, it is unclear from the draft decision or Aurora Energy's CPP determination what these one-off costs are, and/or what services the Commission consider Aurora Energy should be ceasing when the CPP ends in March 2026.
   - Aurora Energy's CPP determination included a 6% annual reduction in System operations and network support (SONS) and people costs. Aurora Energy challenged this decision at the time of the CPP determination and we still hold the view that this annual reduction is not realistically achievable in the current industry context where electrification and increased DER is driving the need for additional resources to plan and deliver growth in an increasingly complex operational environment. It remains unclear how the Commission expects this annual reduction to be achieved.
   - While we don't agree with the rationale for the annual reduction in operating costs over the CPP period, we note that throughout the CPP period Aurora Energy has been subject

to IRIS incentives and penalties based on the reduced level of opex allowances. This has had the effect of ensuring that Aurora Energy's actual revealed opex expenditure during the CPP period is prudent and efficient.

- Through the CPP period Aurora Energy has faced additional opex costs for cyber-security, Software as a Service (SaaS), insurance, and consumer engagement. These costs are now reflected in Aurora Energy's base opex expenditure and therefore have not been recognised as step-changes in the Commission's draft DPP4 decision. Any CPP roll-off base year adjustment, should be offset by step changes for SaaS, insurance, and consumer engagement to ensure Aurora Energy is treated consistently with other suppliers.

The 0% opex Partial Productivity Factor is appropriate.

7. We support the Commission's decision to retain the 0% opex partial productivity factor (PPF). The IRIS mechanism is intended to act as an incentive for suppliers to only incur expenditure that is prudent and efficient. This ensures that an efficient level of operating costs is effectively revealed in the base expenditure. No rational supplier would voluntarily incur IRIS penalties, (or forego opex incentives) for expenditure that was unnecessary or inefficient. Under the current regime, a 0% PPF adjustment is the only logical value that can be applied. Any deviation from the 0% opex PPF would need to be accompanied by changes to the opex IRIS mechanism.

8. The decision to retain the 0% PPF is further supported by the Cambridge Economics Policy Associates (CEPA) EDB Productivity Study 2024 which found no compelling evidence that there has been a real decline in productivity over the DPP3 period, and that there are outputs that consumers value that are not accurately captured in PPF metrics.

Capital expenditure

9. We acknowledge the Commission's challenge in determining appropriate capital expenditure (capex) allowances to support New Zealand's electrification demands against the backdrop of a consumer cost of living crisis. Overall, we feel the Commission have struck a fair balance in their setting of the initial capex allowances.

An effective reopener process is critical to support investment during the DPP4 period.

10. We understand that the Commission's analysis of capex allowances has been partially informed by the analysis of 2024 Asset Management Plans (AMPs). We wish to note that Aurora Energy's 2024 AMP only included projects that we have reasonable confidence will materialise. When preparing the 2024 AMP, we excluded several identified projects for which there was insufficient certainty. If these projects materialise during the DPP4 period it is highly likely that Aurora Energy will need to rely on the reopener process to seek additional capex funding.

11. A review of the draft decision capex allowances compared to 2024 AMPs for other suppliers suggests that reopeners will be a key feature of the DPP4 period. Ultimately the success of the regulatory regime in enabling the energy transition will rest on the Commission's ability to enact

an efficient and well understood reopener process prior to the commencement of the DPP4 period.

The Commission needs to assure the industry that it is appropriately resourced to facilitate timely turnarounds of reopener applications. Alternatively, it should consider outsourcing elements of the reopener process to third parties. We note the Commission's continued preference to assess reopeners on an ex-ante basis. The implications of this approach are that consumer driven projects are likely to be delayed if the Commission is unable to approve reopener applications in a timely manner.

12. To further assist the efficiency of the reopener process for all parties, we request that the Commission publish reopener guidance before the commencement of the DPP4 period. The guidance should cover:

    - Application format and content, with requirements scaled by application size (consistent with the principle of proportionate scrutiny).
    - Application timelines, including Commission response timeframes to allow planning certainty.

Customer connection capex should be removed from the IRIS mechanism

13. The Commission should consider removing customer connection capex from the calculation of IRIS incentives to mitigate the impact of uncertainties that are outside the control of suppliers. This is particularly relevant for the DPP4 period, where an increase in electrification projects is expected. We also note the Electricity Authority are currently considering reviewing Code requirements for Capital Contributions, which could add further uncertainty to the level of consumer connection capex required in DPP4.

Revenue path

14. We understand the Commission is facing unprecedented challenges in determining supplier revenue paths for the DPP4 period. Exogenous economic factors are driving a significant increase in suppliers building block inputs at a time when many consumers are under strain from significant cost of living increases. The Commission have an unenviable task of balancing consumer price shocks against supplier financeability concerns.

15. We appreciate the Commission's progress in addressing the issue of financeability and we think the sense check is a step in the right direction. It is now time for the Commission to evolve their understanding of consumer price impact.

16. The Commission continue to assess consumer price impact on a per ICP basis, which is not appropriate for the DPP4 period. It is a commonly held view that electrification will increase in the next five-years as we forecast an uplift in process heat conversion, a continued uptake of electric vehicles, and households' conversion from natural gas to electricity. All these changes will lead to increased electricity consumption per ICP and a corresponding decrease in expenditure on fossil fuels. To continue to assess price impact on a per ICP basis shows a fundamental misunderstanding of New Zealand's electrification journey.

17. We advocate for using a per kWh measure for assessing price impact. A per kWh measure captures both increases in the number of ICPs and increases in the amount of energy consumed per ICP from electrification. Therefore, it is a better proxy for overall consumer impact, than a per ICP metric.

18. Moving to a per kWh assessment of price impact would also be more in line with how MBIE monitor electricity cost and prices. MBIE's Quarterly Survey of Domestic Electricity Prices (QSDEP) is the most accepted source of measuring electricity costs on a household basis in New Zealand, with electricity costs being measured on a kWh basis.

19. Furthermore, kWh metrics are just as readily available as ICP metrics, being included in both Information Disclosures and AMP forecasts.

20. It is critical that the Commission evolves its understanding and modelling of consumer price impacts.

Setting quality standards and incentives

21. The changes that the Commission made to the quality standards and incentives in DPP3 have now had time to bed in and we support the decision not to make any further wholesale changes to the quality standards and incentive framework at this time.

22. We encourage the Commission to reconsider its decision in DPP3 to move away from the two-out-of-three rule because we consider that rule to be more appropriate as it allows for one-off poor performing years, which alone may not constitute an underlying material deterioration of reliability.

23. Given our own experience with transferring a very small portion (0.15%) of the ICPs on our network to another EDB, we strongly encourage the Commission to introduce a de-minimis threshold in relation to the requirements on an EDB to adjust its revenue and quality path following a transfer.

24. We support the retention of the 'additional notice' framework and how this incentivises EDBs to give sufficient notice to consumers of planned interruptions and to keep them informed. However, we consider that the requirements, which were not fully consulted on during the DPP3 reset, are overly prescriptive and conflict with the Electricity Authority's Electricity Information Exchange Protocol EIEP5A. We suggest, at the very least, that the Commission makes the same changes it did for Aurora Energy in its CPP Determination relating to a 24-hour time format.

25. Adopting a shorter reference period to inform the planned standard parameters is a positive move by the Commission. However, we consider that a seven-year reference period from 1 April 2018 should be used for the final decision, rather than an eight-year reference period as suggested. We consider that the rationale and evidence provided in the Draft Reasons Paper supports this.

Aurora Energy's CPP to DPP transition

26. We welcome the Commission's intended approach to work closely with Aurora Energy ahead of the transition from CPP to DPP and thank the Commission for confirming that the 2025 AMP will be the starting point for assessing forecast capex.

3. Feedback Questions

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:

C1 We support the Commission's use of AMP forecasts as the starting point for setting capex allowances, and agree with the Commission's thinking that Aurora Energy's 2025 AMP should be the basis for Aurora Energy's transition to DPP4.

C2 The use of an arbitrary limit of 125% of the historic reference period may not be appropriate for the DPP4 period when an increase in investment is needed to meet New Zealand's electrification goals. In our view the risk of under-investing, or investing too late, outweighs the consequences of investing too much, or too early, noting that increases in capital expenditure have a relatively minor consumer impact in the short-term, because costs are recovered over the life of the assets.

The Commission also needs to consider how many reopeners it can process in a timely fashion and set a capital expenditure limit that ensures the Commission does not receive more reopener applications than it can manage. Delays in processing reopener applications is a significant risk for the DPP4 period, and if not addressed are likely to lead to delays in investments, including customer-initiated electrification projects.

C3 The five-year reference period is reasonable. We would like the Commission to confirm that the reference period for Aurora Energy's transition from a CPP to DPP4 will be RY21 to RY25.

C4 An allowance for the cost of financing is appropriate.

C5 We have no strong views about applying an allowance for vested assets and spur assets.

C6 We agree that the capex allowance needs to be adjusted for inflation and are unaware of any more appropriate indices than the CGPI.

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:

O1.1 The base-step-trend approach to forecasting is appropriate, provided that adequate step changes are allowed for in the final decision.

O1.2 2024 is an appropriate base year for suppliers that are commencing DPP4 on 1 April 2025. For Aurora Energy, we believe that actual opex for 2025 should be the base year for determining opex allowances when Aurora Energy transitions from a CPP to DPP4 on 1 April 2026.

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 Energy'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:

O2.1 We support the Commission's approach to assessing step-changes in DPP4. However, this approach only captures step changes that can be adequately justified at the time of the DPP4 reset. The DPP regime should also include a mechanism to reopen opex allowances when new step changes emerge during a DPP period. For example, the draft Electricity (Hazards from Trees) Amendment Regulations 2024 will result in increased costs for the industry if they are implemented as proposed.

O2.2 Significant step changes are necessary for the DPP4 to reflect increased supplier costs such as cyber-security, insurance, LV monitoring, and Software-as-a-Service (SaaS). These increased costs will support a more resilient and efficient supply of electricity in the medium to long-term.

O2.3 On balance, the Commission's approach to assessing the reasonableness of step changes in DPP4 is appropriate. We note that, by definition, step changes are expenses that have no historical precedent, so the Commission will need to apply some discretion in determining the quantum of step changes required.

O2.4 We agree that step changes must not be included elsewhere in expenditure allowances.

O2.5 We would like to see this requirement replaced with a requirement that step changes should be in the long-term interests of consumers.

O2.6 We support the relaxing of this requirement and agree that step changes should be widely applicable.

O3.1 Our preference is to treat insurance as a passthrough cost because these costs are mostly outside of the supplier's control. We support the inclusion of a step-change for insurance costs as a 'second-best' option.

O3.2 We support the inclusion of a step-change for greater consumer engagement.

O3.3 We support the inclusion of a step-change for LV monitoring and smart-meter data.

O3.4 We support the inclusion of a step-change for increasing cyber-security costs.

O3.5 We support the inclusion of a step-change for the costs of (SaaS.

O3.6 We do not agree with the rationale for applying a negative step-change for the end of Aurora Energy's CPP period. As outlined in our executive summary we feel this approach is inconsistent with the Commission's base-step-trend approach to forecasting opex. We welcome further engagement with the Commission on this topic.

O3.7 We understand that the 5% cap on opex step-changes has been applied to attempt to balance consumer impact, within the level of scrutiny appropriate for a DPP regime. However, we believe the Commission should consider a higher cap for suppliers that are able to provide stronger evidence to support step changes.

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

O4.1 We urge the Commission to reconsider treating insurance as a Passthrough cost because these costs are outside of the control of suppliers. Cost changes for insurance tend to be driven by international markets and localised risk factors which are not reflected in the Commission's cost escalators.

O4.2 We appreciate the Commission's addition of a 0.3% uplift, however, this is unlikely to be truly reflective of the cost pressures experienced by suppliers.

O5.1 No comment at this stage.

O5.2 No comment at this stage.

O5.3 No comment at this stage.

O5.4 No comment at this stage.

O5.5 No comment at this stage.

O5.6 No comment at this stage.

O5.7 No comment at this stage.

O6.1 As outlined in our executive summary; we believe an opex partial productivity factor of 0% is appropriate for DPP4.

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.

Views/Response:

U1 We support the introduction of an innovation and non-traditional solutions allowance (INTSA).

U2 We support the use of the INTSA to incentivise energy efficiency and demand-side management.

U3 We agree that a reduction of energy losses incentive is not required in DPP4.

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 Energy 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

QS1 We support maintaining separate standards for planned and unplanned SAIDI and SAIFI.

QS2 Annual assessment of unplanned standards for SAIDI and SAIFI was introduced in DPP3. We consider that the two-out-of-three rule that applied in DPP2 remains a better alternative because it would allow for one-off poor performing years, which alone may not constitute an underlying material deterioration of reliability. We encourage the Commission to reconsider introducing the two-out-of-three rule.

QS3 We support retaining the 2.0 standard deviation buffer for setting the unplanned interruptions reliability standard.

QS4 We support maintaining the regulatory period length standard for planned SAIDI and SAIFI. This was a positive introduction to DPP3 that we consider remains important in recognising the need for an EDB to have the flexibility to deliver its work programme across the 5-year period rather than be constrained by annual planned SAIDI and SAIFI limits.

QS5 No comment at this stage.

QS6 We support maintaining the de-weighting of the impact of notified planned interruptions by 50% in the assessment of compliance with planned interruption standards. We continue to receive customer feedback that reinforces the value that is placed on receiving advance notice of interruptions. We believe that the de-weighting acknowledges this.

QS7 No comment at this stage.

QS8 No comment at this stage.

QS9 We support not introducing any new quality measures as a part of the quality standards applying in DPP4. If new quality measures are to be introduced to the compliance framework, they should be signalled well in advance and should be introduced through information disclosure first to give EDBs sufficient time to make and embed any necessary process changes.

QS10 We support setting interruptions quality standards and incentives for Aurora Energy on the same basis as for other EDBs under the DPP. We do not think that there is any justification for applying a different approach.

QS11 While we support, in principle, the requirements for reasonable reallocation of SAIDI and SAIFI following an asset transfer between EDBs, from our own experience, we consider that a de minimis threshold needs to be introduced.

In November 2022 we transferred 144 connections from a small, embedded network to The Power Company. This represented 0.15% of the total number of connections on our network. Despite this, the workload associated with meeting the requirements related to adjusting our forecast net allowable revenue, wash-up amount and our quality standard parameters, were the same as that required for an EDB that was transferring a substantial portion of its network to another.

We consider that there has been little benefit to consumers in us incurring the costs of undertaking these adjustments and consider that a de minimis threshold should be introduced and should have to be met before an EDB needs to comply with the adjustment requirements in the Determination.

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:

QIS1: We support, in principle, retaining the revenue-linked quality incentive scheme for planned and unplanned SAIDI, and that SAIFI remain excluded. However, as we expressed at the time our CPP Determination was made, we consider that the framework for 'additional notice' is too prescriptive and continued to cross over with, and in some places contradict, the electricity information exchange protocols (EIEP) developed by the Electricity Authority, particularly EIEP5A, which is now mandatory.

Our preference is that the Commission remove the prescriptive requirements for "additional notice" as an EDB's compliance with EIEP5A should be sufficient.

Alternatively, at a minimum, we ask that the Commission:

- includes the ability for a 24-hour format to be used for the start time and end time in the definition of "notified interruption window", as it has done for Aurora Energy in its CPP Determination. This aligns with the registry delivery format used for EIEP5A and means that additional content is not required to be provided alongside the registry notification in an am/pm format;
- removes the need for an EDB to record in its internal systems that an interruption is a "Class B notified interruptions". Evidence that the timeframes and notice content requirements have been adhered to should be sufficient for an interruption to qualify for the incentive; and
- changes the requirements of paragraph **4(a)(iv)** of Schedule 3.1 of the draft DPP4 Determination so that an EDB only needs to provide their URL in accordance with EIEP5A without additional information required. EDBs have no control over what the retailer ultimately includes in the notice and therefore this information becomes redundant.

QIS2: No comment at this stage.

QIS3: We support reducing planned incentive rates by 35% relative to the unplanned incentive rate.

QIS4: We support reducing 'notified interruptions' by 75% relative to the unplanned incentive rate to reflect less inconvenience to customers.

QIS5: No comment at this stage.

QIS6: We consider it appropriate to set the SAIDI caps equal to the limits for planned and unplanned SAIDI.

QIS7: We consider it appropriate to set the SAIDI collars to 0 for planned and unplanned SAIDI.

QIS8: We consider it appropriate to cap revenue at risk at 2% of actual net allowable revenue.

QIS9: We support not implementing any new incentive schemes. We consider that the changes made during DPP3 are sufficient to incentivise EDB performance.

QS10: We support not making an explicit adjustment to match the duration of retention benefits between EDBs and consumers.

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.

Views/Response:

N1: We support retaining normalisation only for unplanned interruptions.

N2: We support retaining the normalisation approach used in DPP3.

N3: We support SAIDI and SAIFI major events being triggered independently.

N4: No comment at this stage.

N5: We consider the current additional reporting for each unplanned major event in an annual compliance statement to be appropriate and sufficient.

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:

RP1: We consider that a 10-year reference period is appropriate to inform the parameters for unplanned interruptions reliability standards and incentives, and we support the use of 1 April 2014 to 31 March 2024 for the final determination.

RP2: We consider that a seven-year reference period is appropriate to inform the parameters for planned interruptions and that the Commission should not extend this to an eight-year reference period for the final decision.

Instead**,** we consider that the reference period for the final decision should start at 1 April 2018. The Commission acknowledges in paragraph E398 of the Draft Reasons Paper that it has seen a step change in planned interruptions across non-exempt EDBs. Figure E4 of the Draft Reasons Paper depicts that step change, particularl**y** from 2018, which we consider supports the use of a seven-year reference period beginning 1 April 2018.

RP3: No comment at this stage.

RP4: We support there being no explicit step changes to reliability targets or incentives.

RP5: No comment at this stage.

RP6: We consider that recording successive interruptions on the same basis as employed in responding to the s 53ZD notice is appropriate.

RP7: We support excluding interruptions directly associated with an approved INTSA project to encourage innovation by EDBs.

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.

Views/Response:

P1 We support this approach to setting starting prices.

P2 We support the use of a default rate of change of 0%.

P3 We accept that some degree of price smoothing is required to moderate the impact on consumers and we agree with the Commission's approach that all allowable revenue should be recovered within the DPP4 regulatory period.

P4 As outlined in our executive summary, we do not agree with the Commission's approach to assessing price shock. Price shock also needs to consider changes in the quantity of electricity consumed.

We would also like the Commission to confirm that, for Aurora Energy's transition from CPP to DPP4, the initial price shock limit of 20% will be measured as the change in prices between RY26 and RY27.

P5 We have no comments on this topic.

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:

I1 We agree that the IRIS retention rate for capex and opex should be the same.

I2 We agree that IRIS should be calculated in real terms, however CPI is unlikely to be the most accurate inflationary measure, especially for capex. The Commission should consider adopting the CGPI as a better measure of real capex increases.

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.]

Views/ Response:

R1.1 We agree with using a revenue cap and wash-up as the form of control.

R1.2 We have no comments on this topic.

R1.3 We question why a **voluntary undercharging limit** is required, considering a revenue smoothing limit is in place to moderate year-on-year consumer impact. The voluntary undercharging limit only serves to limit the size of accumulated wash-up balances and may restrict a supplier's ability to manage customer price impacts and lead to more volatile prices.

R1.4 We agree a LCC wash-up adjustment is required.

R1.5 We believe there should be a materiality threshold included in the asset transfer provisions to protect the long-term interests of consumers. Aurora Energy have experienced a situation where the administrative costs of complying with the asset transfer provisions exceeds the value of the calculated revenue transfer.

R2.1 We have no comments on this topic.

R2.2 We believe the revenue smoothing limit should be adjusted for changes in the quantity of electricity supplied to ensure the smoothing limit is a better proxy of consumer impact and suppliers with faster growing networks are not disadvantaged.

R3.1 We have no comments on this topic.

R3.2 We have no comments in this topic.

R3.3 We have no comments on this topic.

R3.4 We have no comments on this topic.

13. Other Matters

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

Views/Response:

X1 We support the retention of a five-year regulatory period.

X2 We support the inclusion of Aurora Energy in the DPP4 process and welcome engagement with the Commission prior to the setting of Aurora Energy's final allowances.

X3 We support the retention of the CPP application timings.

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:

M1 No comment at this stage.

M2 We support this approach.

M3 We support the approach to forecasting depreciation based on information supplied by each EDB.

M4 We support the use of the 2024 Information Disclosures as the base data for the final DPP4 decisions. We would also like the Commission to confirm that it will use the 2025 Information Disclosures as the base data for Aurora Energy's transition to DPP4.

M5 We support the use of the most recently available RBNZ MPS forecast for determining CPI forecasts.