19 July 2023
Commerce Commission
Level 9, 44 The Terrace
Wellington 6011
By email to im.review@comcom.govt.nz

To whom it may concern,

Alpine Energy Limited's submission on the Commerce Commission's draft Input Methodologies

Introduction

1. Alpine Energy Limited (**Alpine Energy** or **we**) thanks the Commerce Commission (**the Commission**) for the opportunity to submit on the draft decision and supporting reports on the Input Methodologies (**IMs**) review relating to electricity distribution businesses (**EDBs**), gas distribution businesses (**GDBs**), gas transmission business (**GTB**), Transpower and regulated airport services, dated 14 June 2023.
2. We are pleased to see that the Commission's draft decision and supporting reports recognise that the energy industry is facing times of uncertainty, rapid change, and transformation, coupled with significant uplifts in forecast expenditure over the short, medium, and long term. We were also pleased to see the recognition that regulated suppliers will face different challenges based on their network characteristics and consumer drivers.
3. As we have highlighted in our current Asset Management Plan (**AMP**)[1] the scale and scope of change on our network is significant in comparison with the capacity and size of our network. The Mid-South Canterbury Regional Energy Transition Accelerator (**RETA**)[2] report, published in June 2023, highlights the extent of large-scale decarbonisation projects which could eventuate in the next ten years and the capacity constraints in certain areas of our network.

[1] https://www.alpineenergy.co.nz/__data/assets/pdf_file/0029/18983/AMP-2023-WEB_FINAL.pdf
[2] https://www.eeca.govt.nz/assets/EECA-Resources/Co-funding/EECA-Mid-South-Canterbury-RETA-Report.pdf

4. Our customers must have the opportunity to make informed energy choices and we are a key enabler of this. We therefore need a regulatory framework that provides us, and the industry as a whole, with sufficient and appropriate tools to enable the New Zealand energy transition and ensure the best long-term outcomes for consumers.
5. The regulations should also be fit for purpose within the New Zealand context. We support drawing on the experience of international regulators for mechanisms and rules, and the practical application of these. However, we are concerned that some of the draft decisions are based on international regimes without appropriately considering the impact on small, regional New Zealand businesses and communities.
6. While we welcome most of the changes proposed in the draft decision, we believe amendments are required to ensure the suitability of the IMs as we head into a new regulatory period.
7. EDBs, and the wider energy industry, need to plan and prepare for the impacts climate change, decarbonisation, and electrification, while upskilling our workforce to cope with the changing technologies and digital disruption. This will all result in an uplift in forecast expenditure which is likely to remain through the next two regulatory periods, as we move closer to New Zealand's net zero emissions target or 2050.
8. As a member of Electricity Networks Aotearoa (**ENA**), we largely support the submission prepared on behalf of the members. We specifically support the concerns raised in respect of the draft decision on the cost of capital.

Welcomed changes

9. The New Zealand energy industry, and EDBs in particular, are at a pivotal point where the industry is already witnessing and delivering rapid change driven by electrification to decarbonise the New Zealand economy.
10. The Commission's draft IMs propose to introduce a new mechanism to address expenditure uncertainties related to the timing of Large Connection Contracts (**LCC**). Alpine Energy generally supports the proposed mechanism. We believe that this is a step in the right direction to eliminate cross-subsidisation of lines charges and benefit all our consumers, large and small, in the long term.
11. Alpine Energy supports the Commission's draft decision to change the innovation project allowance mechanism by removing the definition of an innovation project and by broadening the scope to include non-traditional solutions within the allowance.

12. Alpine Energy also supports the Commission's decision to adjust the incremental rolling incentive schemes (**IRIS**) allowances for inflation and use the mid-point discount rate in the opex IRIS computation. We believe this recognises that opex may increase over the regulatory period as technology moves to cloud-based solutions and new skills and capabilities are introduced to respond to digital disruption.

13. We welcome the Commission's draft decision to address inflation forecasting risk through the adjustment for a wash-up for year one of the regulatory period. We also support replacing the existing maximum allowable revenue (**MAR**) wash-up with one that calculates a wash-up amount by re-running the building blocks model for the regulatory period in question, using actual consumer price index (**CPI**) in place of the forecasts used originally.

14. Alpine Energy supports the Commission's draft view that it can manage risk of consumer price shocks, by smoothing price increases over multiple years setting an 'alternative rate of change' for a particular supplier if deemed desirable to minimise price shocks. Achieving price stability over both the short-term and long-term, will best promote the long-term benefit to consumers.

15. We welcome several of the Commission's draft changes to the IMs relating to the price-quality path reopener provisions. We are encouraged by the Commission extending reopeners to include opex solutions and capturing opex solutions within system growth expenditure. These decisions will assist the industry as it looks for new, non-network opportunities to support decarbonisation efforts.

16. We are also supportive of the introduction of provisions to protect confidential information. As we sign non-disclosure agreements with many of our large-scale customers, this is a welcome addition to ensure our customers' interests are sufficiently protected. This also promotes the section 52R purpose by providing more clarity in how to deal with confidential information.

Large connection contracts

16. Alpine Energy generally supports the proposed mechanism in the Commission's draft IMs. However, we believe that the maximum capacity of the connection contract should be based on peak demand for specific regions/EDBs rather than a single blanket threshold across all EDBs.

    a. The Commission defines 'large' connections as contracts with a maximum capacity of at least 10MW. Given our network size, scale, and general size of customers in the region, we believe the threshold should be set at a maximum of 1% of peak demand (which is in line with the historic average size of new or amended connections across our region) to promote outcomes consistent for the region.

b. The supplementary information on potential load characteristics accompanying the RETA report[3] indicated that, of the load sites identified as large decarbonisation projects in South Canterbury, only three of the thirteen potential projects had indicative loads of more than 10MW.

c. The first industrial decarbonisation project we delivered in Washdyke, Timaru, during 2023 had a load of 8.5MW, which equates to 40% of the current demand in Washdyke.

d. We therefore urge the Commission to strongly consider changing the threshold to be more representative of network capacities and demands.

17. We also seek more clarity from the Commission to ensure that, for any future assets installed through this mechanism, the rules remain consistent during the asset's economic life and commercial term, with minimal regulatory compliance costs. The Commission also needs to provide clarity and certainty on the treatment of projects that are already in motion, and the implications on the current DPP and information disclosure requirements.

Weighted Average Cost of Capital

18. Currently, New Zealand is experiencing a period of high inflation and high interest rates at levels not experienced since before the global financial crisis. The official cash rate (**OCR**) has increased at record speed to 5.5%, after being at an all-time low of 0.25% during the pandemic to combat high inflation. This is by far the fastest increase in the OCR that New Zealand has witnessed this century.

19. The economic/capital market uncertainties coupled with industry uncertainties driven by decarbonisation has a cascading impact on the weighted average cost of capital (**WACC**). While we could expect to see a decline in interest rates over the next DPP period, decarbonisation related investments would have a major balance sheet impact for regulated suppliers and our ability to fund the expenditure, given revenue pass-through constraints.

20. Against this backdrop, the Commission's draft view is to reduce the WACC percentile from the 67th to 65th percentile (effectively reducing the overall WACC). We question the rationale behind this draft decision, given the significant investment requirements for decarbonisation and electrification.

[3] https://www.eeca.govt.nz/assets/EECA-Resources/Co-funding/South-Canterbury-Spare-Capacity-and-Load-Characteristics.pdf

21. The Commission's draft view is to maintain its current approach of estimating the risk-free rate used in the cost of debt and cost of equity calculations. Currently, for both information disclosure and the default price-quality path (**DPP**) setting purposes, the Commission estimates the risk-free rate using a three-month arithmetic average of prevailing wholesale New Zealand dollar denominated government bonds with a maturity period equal to a DPP regulatory period.

    a. While Alpine Energy generally supports the approach of using the prevailing market bid yields to establish the risk-free rate; we believe that the Commission should consider a longer observable period rather than a relatively short three-months window for setting the risk-free rate used in the WACC calculations. The current volatility in global capital markets, coupled with the relatively short observable period, could potentially result in perverse outcomes over the full DPP regulatory period. Further, market volatility is likely to produce outcomes which are unfavourable for consumers and suppliers alike during the full DPP period. Hence, we urge the Commission to consider a longer observable period to estimate the risk-free rate used in the WACC estimation process.

22. The Commission's draft view is to maintain its current approach of past trends and judgment-based methods to estimate the tax adjusted market risk premium (**TAMRP**). The Commission accurately asserts that the '*TAMRP is a forward-looking concept which cannot be directly observed*'. We agree with the Commission's assertion that the TAMRP is not directly observable, and support the theoretical approaches followed.

    a. However, we urge the Commission to consider a more frequent estimation of the TAMRP as it would better align with market conditions prevailing at the time. Alpine Energy is of the view that the Commission should, at a minimum, estimate the TAMRP as part of the DPP WACC determination process.

23. The Commission's draft view and the current IMs do not have an explicit allowance to cover the cost related to equity raising/issuance. We urge the Commission to reconsider this position. Alpine Energy may need to seek additional equity to fund network growth driven by decarbonisation. Hence, we are of the view that it is inconsistent to exclude the equity issuance cost from the WACC, given the Commission's acknowledgement of the uncertainties faced by the industry and the wider economy.

    a. As a minimum, we urge the Commission to consider an allowance to recover equity raising costs should a situation eventuate where equity raising is required to fund network growth.

Inflation risk

24. Since 2021, inflation has been well above the RBNZ's mid-point target of 2% and currently hovers around 7%. The RBNZ expects inflation in New Zealand to decline, however, we believe, core inflation pressures will remain until capacity constraints ease further. As per the latest monetary policy statement (**MPS**), inflation is expected to return to the RBNZ target range of 1% to 3% by late 2024. However, there is significant risk of a long-term neutral rate sitting above 2% over the DPP4 period.

25. Since the pandemic, New Zealand has observed high variability in inflation. We believe that the Commission could have a better approach in forecasting inflation to minimise the mismatch of actual versus forecast inflation. Discrepancies between actual inflation and the Commission's expected inflation puts pressure on EDBs financeability metrics as it will mean funding the delta until the revenue wash-up can be realised. This may impact compliance with bank covenants and would also have cash flow implications due to asset indexation.

26. The Commission's draft decision is to retain the current inflation forecasting method risks generating significant forecasting errors and is unlikely to be fit for purpose. Using the best CPI forecast is particularly relevant now due to the uncertainty in the current economic climate.

27. We suggest the Commission **further explores and tests** various alternative approaches in forecasting CPI, especially the glide-path and survey approaches in estimating long term inflation projections. There are various alternatives that the Commission can consider as applied by regulators overseas.

28. The Commission is of the view that RBNZ forecasts always end in the target range, and a glide-path approach is therefore irrelevant. However, if inflation remains above the RBNZ's mid-point target for an extended period, the probability of de-anchoring medium-term expectations increase.
    a. If this de-anchoring were to occur, a glide-path approach is likely to produce inflation expectations that are closer to market expectations compared to the Commission's current approach.
    b. A glide-path approach provides a provision for de-anchoring inflation expectations in the coming years and is an approach that is transparent and replicable.
    c. There are key decisions to be made including defining the length of the glide-path. The glide-path approach has been adopted since the pandemic by regulators in Australia, acknowledging the need to adopt a different approach to address the mismatch problem.

29. A survey approach will de-risk the reliance of a single point forecast and ranks highly in terms of relative congruence as professional forecasters invest substantial time and effort to ensure their models track changes in information relating to the formation of inflation expectations. Further, a combination of a survey approach and a glide-path could also be considered as an alternative, similar to the Commission's approach in estimating the TAMRP.

Approach to incentivising efficient expenditure

30. Alpine Energy welcomes the Commission's draft decision to maintain the overall mechanics of the IRIS. Whilst we acknowledge that the IRIS workings are complex and less intuitive than other mechanisms in the draft IMs, we believe the level of complexity and detail is necessary to achieve the desired outcomes.

31. Alpine Energy is already witnessing a marked increase in capex and opex spend driven by decarbonisation and electrification. This is forecast to substantially increase over the next 5-10 years. As part of this, we are constantly exploring alternative ways to deliver network solutions that better meet the energy needs and expectations of our region and communities.

32. We are increasingly exploring options to utilise non-network digital solutions as a means to manage network load, therefore, we expect non-network solutions to become more important in network planning in the coming years. Hence, we require greater flexibility to consider non-network solutions and certainty of the rules, regulations, and processes.

    a. If there is no mechanism available to find or recover the investment in digital technology, adoption, and management of new technologies, like solar photovoltaics, and other non-network solutions, the incorporation of these alternatives in network planning will be delayed. We believe this will not benefit the consumers in the long-term as we need to be ready to respond to the changing consumer needs.

    b. Alpine Energy's view is that the status quo in terms opex and capex allowance within the DPP should prevail, with the Commission placing greater emphasis on supplier forecast when setting expenditure allowances.

33. Alpine Energy supports the Commission's draft approach to maintain the opex incentive rate as a function of the retention period, and the WACC for the respective DPP regulatory period. The retention period is currently set at five years, which is effectively the length of time the regulated suppliers are able to retain any savings/losses relative to the opex allowance. In our view, the retention period should remain consistent with the DPP period to better align the IRIS incentive mechanism with the price-quality regulation.

34. We are also of the view that the Commission should ensure equivalence between the opex and capex retention rates, whereby the capex retention rate is set to be equal to the corresponding opex retention rate for the respective DPP control period. Alpine Energy believes that this treatment is logical and consistent in delivering both capex and opex outcomes.

35. Alpine Energy welcomes the Commission's proposed intention to adjust the opex and capex allowances used in the computation of the IRIS incentive to account for economy-wide inflation. Currently, IRIS related rewards and penalties are computed based on the DPP allowance versus actual spend, with suppliers being exposed to industry-wide inflation which is beyond the control of regulated suppliers.

36. The Commission's proposed approach in the draft IMs is to:

    a. Set both the opex and capex allowances in nominal dollars, based on the specific forecast cost inflators as at the DPP reset;

    b. Convert the nominal IRIS allowances (equivalent to the nominal DPP allowances) to real IRIS allowances using the forecast Consumer Price Index (**CPI**); and

    c. Use the actual ex-post CPI to compute the IRIS allowances used in incentive calculation.

37. Fundamentally, we do not foresee an issue with the approach of converting nominal allowances to real dollars, and subsequently using ex-post escalation rates to convert real dollars back to nominal dollar IRIS allowance for the explicit purpose of adjusting the IRIS allowances for inflation. However, Alpine Energy does not agree with the Commission's proposed use of the forecast CPIs to convert nominal IRIS allowances to real dollars and subsequently using the ex-post CPI to calculate the nominal dollar allowances. We believe the use of CPI is fundamentally inconsistent as the DPP opex allowances are based on a mix of labour cost index (**LCI**) and producer price index (**PPI**), whilst the capex allowances are based on the capital goods pricing index (CGPI).

38. Alpine Energy is of the view, that the Commission should instead consider using the forecast values of LCI, PPI, and CGPI cost inflators used in setting the DPP allowances to deflate opex and capex IRIS allowances respectively. Subsequently, using the ex-post LCI, PPI and CGPI to convert the real IRIS allowances to nominal dollars. We believe this approach is more consistent with the DPP process and would avoid any potential adverse outcomes relating to escalations and de-escalations.

39. Given that industry wide inflation is beyond the control of regulated suppliers and the fact that commercial contracts are potentially based on escalation rates that differ from LCI, PPI and CGPI; the more pragmatic and realistic approach would be to set the IRIS allowances in real dollars and allow regulated suppliers to convert the nominal dollars in line with true cost escalation faced by regulated suppliers. This would better promote outcomes consistent with workable competitive markets.

Volume wash-up mechanism of new connections

40. As correctly pointed out by the Commission, the regulated suppliers have little to no control over the timing of customer-initiated demand, the increase in demand from EV uptake, or organic growth in connections. We welcome the Commission's proposed approach on the new connection wash-up mechanism for a customised price-quality path (**CPP**).

41. The Commission's proposed mechanism is to:

    a. Determine the ex-ante connection cost by type of connections;

    b. Forecast the number of connections by type;

    c. Calculate the wash-up based on the difference in forecasted connection capex and actual connection capex whilst holding the cost per connection constant; and

    d. Recover the connection capex wash-up via the aggregate price path wash-up.

42. In theory, we do not see an issue with the Commission's approach outlined above, as it generally aligns with the wider regulatory construct. However, we believe that the capex estimates should flow through the building blocks (return of capital) construct to avoid any unintended outcomes. We believe that the Commission could potentially follow an approach identical to the capex wash-up mechanism whereby the Commission estimates the difference in building blocks allowable revenue (**BBAR**), driven by the outturn in connection capex, with the recovery flowing through the aggregate wash-up calculations.

43. Further, we would encourage the Commission to consider extending the connection volume wash-up mechanism to capture DPPs as well as CPPs. We believe the Commission has a wealth of data from past information disclosures, and we are happy to provide any additional supporting information, either via s53ZD notice or through the DPP consultation process, to see this mechanism captured in the DPP IMs and more specifically from DPP4 onwards.

Price-path reopeners

44. We welcome several of the Commission's draft changes to the IMs relating to the price-quality path reopener provisions. However, we urge the Commission to reconsider its draft decision to not extend the DPP reopeners to capture central government policy and local government rule changes.

    a) It is the Commission's view that costs arising in response to government policy are more appropriately managed within reprioritisation of existing expenditure allowances, as suppliers can make decisions on whether to respond or not. And that local government rule changes that are legislative or regulatory requirements are already covered by the "change event" reopener.

    b) We acknowledge this is the case for some central and local government policies and plans that establish direction rather than requirements. However, we submit that the draft determination on "change event" reopeners is ambiguous and excludes central and local government policy and planning frameworks that establish legal and regulatory requirements with material impacts on EDBs, in the same way as legislation does.

    c) National Policy Statements (**NPS**), issued under the Resource Management Act (**RMA**) require local authorities to amend regional or district plans to give effect to these policies.

    d) For example, the National Policy Statement for Urban Development (**NPS-UD**), or National Policy Statement for Renewable Electricity Generation (**NPS-REG**) set requirements for local authorities which can have a significant impact on land use and, as a result, can drive the need for significant and unforeseen network investment.

    e) It is currently unclear whether the issuing of an NPS by central government, or the enforcement of a NPS by local government through a regional or district plan change is covered by clause 4.5.5 (2) of the draft IMs – "a change in a regulatory or legislative requirement that applies to an EDB as a result of new or amended legislation."

    f) NPS and local government plan changes are not "new or amended legislation". However, the requirement for EDBs to comply with local government planning rules resulting from the NPS is the same as that for new or amended legislation. We are not able to make decisions on where to respond or not as the Commission argues in relation to costs arising from government policy.

g) We also submit that limiting reopeners to purely legislative changes, as presented in the draft determination, does not appropriately consider to the current central government policy reform programmes underway, particularly the Resource Management Reform. The Natural and Build Environment (**NBE**) Act will require regions to develop NBE plans. These will be combined plans covering both resource allocation and land use for a region. We question whether it is the Commission's intent to exclude these plans from "change event" reopeners in the future.

h) Government policy development and changes, like NPS, are clearly beyond the control of regulated suppliers. Providing a DPP reopener for central and local government policy and plan changes, like NPS and district plan changes, would not reduce incentives to improve efficiencies, and suppliers are not able to make decisions on whether to respond or not.

i) We request that the Commission considers amending clause 4.5.5 (2) of the draft IMs as follows:

"a change in a regulatory or legislative requirement that applies to an EDB as a result of new or amended legislation and government or local government policy or plan".

45. We encourage the Commission to establish clearer details on the reopener process and process timelines, outlining possible guidelines on required information and application evaluation periods. This will provide EDBs with more clarity around costs, efforts and timeframes required to undertake a reopener and to plan accordingly.

46. We further encourage the Commission to consider the implementation of a templated 'fast-tracked' reopener for those events likely to impact all EDBs equally regardless of size, for example a change event from legislative change. To apply for a reopener requires the same resourcing regardless of EDBs size and it is therefore relatively more expensive for smaller EDBs to navigate a reopener. Given reopeners are likely the only practical avenue to pursue due to the significant cost of preparing and applying for a CPP, we urge the Commission to consider streamlining the process in order to minimise regulatory costs associated with reopeners so as to ensure reopeners are accessible for all.

47. Alpine Energy is also concerned with the Commission's draft view on the foreseeable/unforeseeable major capex projects, and the exclusion of general growth projects from the unforeseeable capex reopeners. We do not see the merit in distinguishing between foreseeable and unforeseeable capex reopeners. Therefore, we suggest that the Commission look to simplify the categorisation of reopeners.

48. Alpine Energy seeks clarification on whether multiple similar events occurring in a given regulatory year can be covered via a single reopener application. The Commission's draft IMs is silent on this matter. We ask the Commission to provide clarity or revise the IMs to enable EDBs to capture multiple events under a single reopener application.

49. As an example, it is possible for several of our current heat processing customers decide to decarbonise their operations from coal to electricity at similar times, and all in the Timaru region. Individually, it is unlikely for the growth capex to meet the draft reopener's lower materiality threshold, however, collectively, these events could. Therefore, we strongly urge the Commission to clarify this issue, or amend the IMs accordingly.

50. We also urge the Commission to reconsider its draft decision to increase the reopener threshold from $2 million to $2.5 million. As per the supplementary information on load characteristics[4] accompanying the RETA report, only three of the thirteen projects included in the study are expected to meet the reopener threshold.

    a. The lack of flexibility of not being able to apply for reopeners on smaller sized projects will inevitably mean that customers will have to pay contributions in full or will alternatively lead to other work programmes being deferred in order to fund customer-initiated work.

Catastrophic events

51. The Commission's draft view is to change the basis for establishing the threshold for catastrophic events from an impact on revenue test to an incurred cost test.

52. Alpine Energy is of the view that EDBs should not be required to absorb the costs of catastrophic events into their expenditure allowances. Doing so will require EDBs to defer planned expenditure to later regulatory periods, which may not be in the best long-term interests of consumers. If the Commission decides to make this change, we urge the Commission to consider removing expenditure on catastrophic events from the IRIS calculation.

---

[4] https://www.eeca.govt.nz/assets/EECA-Resources/Co-funding/South-Canterbury-Spare-Capacity-and-Load-Characteristics.pdf

Conclusion

53. If the Commission has any questions or requires clarification on any information provided in our submission, please do not hesitate to contact us.

Yours sincerely

[redacted]

Marisca MacKenzie
Chief Regulatory Officer
[redacted]