Chairman: Warren McNabb, [redacted]
Secretary: David Inch, [redacted]

19 December 2023

Ben Woodham
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By email: infrastructure.regulation@comcom.govt.nz

Dear Ben,

RE: Submission on EDB DPP4 reset

The Independent Electricity Generators Association (IEGA) welcomes the opportunity to engage on the Commerce Commission's (Commission) analysis of key issues for the reset of EDB's Price-Quality path from 1 April 2025. [1]

The IEGA represents commercial distributed generation. We are focused on the opportunities for distributed generation to meet incremental growth in electricity demand, operate to meet peak demand, as well as defer or avoid new infrastructure investment by being contracted as a non-network solution by the EDB.

Non-traditional solutions and ACOD

The IEGA submitted on the ID and IM Reviews that we did not support the change from 'non-network solutions' to 'non-traditional solutions'. The Commission's IM decision might make it clear to EDBs that anything 'non-traditional' is anything "instead of traditional lines solutions".[2] That is distributed generation is a non-traditional solution because it is not electricity lines. The IEGA requests a meeting with the Commission to understand the rationale behind this change and the Commission's expectations of EDBs in relation to alternatives to networkinvestment.

The IEGA supports the Commission's IM decision "to introduce a mechanism that enables a wider set of incentive schemes, including to improve incentives for opex/capex substitution across regulatory periods". We hope these changes encourage distributed generation as a non-traditional solution. If

[1] The Committeehas signed off this submission on behalf of members.

[2] Paragraph X59, page 19. 'Part 4 IM Review Final Decision – Risks and Incentives Topic Paper', 13 December 2023

the Commission is proposing any workshop to discuss non-traditional solutions and the incentive mechanism the IEGA welcomes the opportunity to participate in this discussion (Q22).

The Commission asks if there is a basis for strengthening the incentives for energy efficiency and demand-side management initiatives.[3] Energy efficiency relates to using less energy overall. Demand-side management (DSM) initiatives relate to changing the time of energy consumption – with the objective to reduce demand during peak periods which is what drives the requirement for additional network capacity. DSM are more likely to be activities that are non-network/traditional solutions that avoid or defer new capacity investment. If the Commission decides to incentivise EDBs to initiate more DSM activity, this activity must be contestable with the incentives applying to all activities that reduce peak demand on the distribution network – such as distributed generation generating during periods of peak demand. The previous incentive to manage load and generate during periods of peak demand (transmission interconnection pricing based on RCPD) was very successful. Transpower has been clear that the removal of RCPD pricing has resulted in peak demand increasing faster than historic rates in the last 2 years.

The Commission discusses Avoided Cost of Distribution payments (ACOD) in the context of costs that could trigger a step change.[4] The Commission is correct that EDBs have not been paying ACOD payments to distributed generation that has reduced or avoided network investment.

Whether distributed generation is a non-traditional solution or a demand-side initiative, the historic approach to not paying for ACOD can not continue. The increased focus on 'flexibility services' which includes distributed generation should result in increased payments of ACOD to distributed generation and all flexibility service providers. However, we agree that higher ACOD payments are not a 'step change' as they will reflect the most efficient solution to address network issues.

Context andchallenges

We agree with the Commission's high-level description of the context and challenges for EDBs and support the Commission's acknowledgement that this "*DPP4 will heavily influence EDBs' decisions about how they make the necessary investments to address the challenges they face in meeting their consumers' needs*".[5] We suggest EDBs are already making decisions that impact the sector's success in achieving international climate change commitments – that is, the regime should be a continuum and not a new start point on 1 April 2025.

The Commission is likely the most informed government agency about the activity and performance of the distribution sector. The Commission is also aware of the Boston Consulting Group estimate of investment by the distribution sector of $22 billion during the 2020s.

The IEGA is interested to understand the Commission's view about what needs to happen in the distribution sector in the next 5-7 years to achieve NZ's climate change goals, especially our 2030 commitments? For example, should the Commission have oversight of the applications for new or expanded connections to distribution networks to understand the quantum, location and timeframes for this growth. If current EDB activity under the light-handed Price-Quality regime looks like it is not

[3] Para 4.25, Q24 & Attachment I of the Issues Paper
[4] Para D180-D188 of the Issues Paper
[5] Para 2.9 of the Issues Paper

going to deliver the activity by regulated entities that is needed to deliver international climate change commitments would the Commission intervene / revise the regime to be more facilitative?

A recent survey of energy sector leaders revealed several saying that NZ won't get to our 2030 international commitments.[6] The current cost of underachieving domestic emission reductions is estimated by The Treasury to be $23.7 billion[7] (ie purchasing emission reductions from overseas projects).

We also suggest the Commission's focus is very much on the load / demand side. As already discussed, there is significant potential for newly connected generation to offset this demand within the network avoiding network infrastructure investment. We recommend the Commission encourage an improved approach to connecting new generation as alternatives to network investment. EDBs' approach to the connection of new distributed generation can / does impact the location of new renewable generation. Is it appropriate that an EDB is 'pre-determining' the timing/location of generation, especially if the proposed generation is close to load growth?

The IEGA strongly suggested to MBIE that they undertake model a cost benefit analysis to establish if the overall costs to consumers will be less when generation is built and connected to distribution networks compared with utility-scale generation that requires (forecast ~$30 billion) upgrades and/or new transmission lines to transport electricity to load centres as well as increased connection capacity between transmission and distribution networks.[8] This could determine the optimal mix of distributed generation and network infrastructure investment that results in the lowest overall system costs for electricity consumers.

Capital expenditure forecasts

We suggest that the Commission also focus how EDBs can be encouraged to increase the capacity utilisation of existing assets. The load factor across the sector is ~59% on average over a year. This obviously changes by time of day, day of week and seasonally but there is currently excess capacity. The cost of ensuring assets are used more must be less than the cost of new infrastructure. Connecting generation to local distribution networks can increase utilisation of existing assets. It is also an incremental way of increasing supply of electricity close to load growth forecast as households and businesses decarbonise their activities. The Commission could measure and monitor load factors. EDB capex forecasts could be reviewed with a lens of increasing use of existing capacity before investing in new capacity, if and when appropriate.

The IEGA notes that forecast capex on asset replacement and renewal is ~+$200m when system growth is ~+$800m in 2026-2030 compared with 2018-2022.[9] We query if this ratio is intuitive when it is widely acknowledged network assets are aging and the risk of asset failures increasing.

[6] KPMG 30 Leaders report

[7] Source:https://www.treasury.govt.nz/publications/climate-economic-fiscal-assessment/nga-korero-ahuarangi-me-te-ohanga-2023#foreword

[8] IEGA submission on MBIE's 'Measures for Transition to an Expanded and Highly Renewable Electricity System' Issues Paper, November 2023

[9] Figure E3, page 142 of the Issues Paper

In IEGA's view deliverability risk[10] on capex should also take into account the intersection of transmission and distribution assets. For example, there may be locations where Transpower has a Major Capital Project approved to increase transmission capacity and electricity delivered to a particular region, but the EDB side of GXP does not have enough capacity and the EDB may not be able to fund an increase in capacity. It also works in the other direction, connection of a distributed generator may require an increase in GXP capacity if there is electricity exported. The distributed generator is aware of the process it is in for its connection asset but has no visibility of the distributor's efforts to increase the capacity of other parts of its network.

Transpower is publishing information about new connection applications and its identified. There is no such disclosure by EDBs. This capital investment requires increased co-ordination and visibility.

Quality standards

The Commission needs to consider the interaction between EDB and Transpower quality standards. Do the requirements on EDBs deliver the 'quality' that Transpower is required to achieve. Put the other way, is Transpower imposing additional quality levels on EDBs because of uncertainty about demand side that are unnecessary from Commission's perspective to achieve the Price-Quality statutory objective?

Further, the current arrangements take an aggregate or "whole of network" approach to setting quality standards. This can camouflage poor performance that is having a substantial impact on consumers in particular parts of an EDB's network. The Commission should hold EDBs to account for their performance even when parties are connected to singular assets with different quality standards or when paying for less than n-1 security to manage costs. We therefore disagree with the Commission's conclusion that "*this issue is unlikely to be material because SAIDI and SAIFI treats each ICP equally".*[11]

The IEGA agrees that "*compliance with the quality standards and penalties under the QIS do not act as a potential impediment to innovation*".[12] However, we query how the Commission might take account of poor or non-performance of a non-network/traditional solution. Is the Commission proposing to take the whole non-network/traditional solution activity outside the Price-Quality regime/regulation? We suggest this should be discussed in the workshop proposed in Q22 and paragraph I18 (and discussed above).

Accelerated Depreciation

The IEGA is surprised the IMs allow for assets to stay in an EDB's RAB "even though they have ceased to be used (ie, become physically stranded)".[13] In a situation where a non-network/traditional solution could make a network asset physically stranded the IEGA queries the incentive on the EDB to contract that non-network/traditional solution. And would the EDB's approach to a non-network/traditional solution be different under this scenario depending on whether the EDB (or a third party) owned the

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[10] Discussed in para 3.29, page 30 of the Issues Paper

[11] Discussed in paragraphs F104-F106 of the Issues Paper

[12] Paragraphs F97-101 of the Issues Paper

[13] Paragraphs G27 of the Issues Paper

solution? Further, is receiving a regulated return on and of capital employed on a physically stranded asset that is no longer being used consistent with a workably competitive market?

Insurance

The IEGA notes EDBs are experiencing higher and increasing insurance charges – this is also members' experience with generation assets. Generators and EDBs can have some influence over these costs but overall risks are assessed in an international market and NZ is a price-taker (unless self-insurance is adopted).

Definition of Distributed Flexibility

MBIE's recent Issues Paper 'Measures for Transition to an Expanded and Highly Renewable Electricity System' included a very useful definition of Distributed Flexibility.[14]

MBIE uses "the term 'distributed flexibility' to describe all types of demand side flexibility, demand response and flexibility from distributed generation and batteries. Distributed flexibility can be provided by large scale distributed energy resources (DER), or household-level consumer energy resources (CER)."

> "DER are business-owned assets, and their primary purpose can be either to provide energy system services or to provide business services. They are generally larger in kW/kWh and can be connected at any voltage level on the distribution network. DER can be generation, storage and demand assets. Examples include medium-sized solar farms, wind farms, batteries, commercial EV fleet charging, and industrial and commercial demand-side response from equipment or buildings."
>
> "CER are (residential) consumer-owned assets, and their primary purpose is to provide a non-energy system service such as heating a home or transportation. However, they can also control their operation to provide energy system services. CER are generally smaller in kW/kWh size and they are connected to the low-voltage distribution network at the consumer's premises. CER can include generation, storage, and demand assets, and common examples include EV charging (including vehicle to gird (V2G)), hot water, heat pumps, heating, ventilation and air conditioning (HVAC), home appliances, small-scale batteries and rooftop solar or small-scale wind." [15]

IEGA members' assets are 'DER' – business-owned generation (including batteries) connected to any voltage level on the distribution network. In our view, the key difference between DER and CER is scale and the increasing requirement for co-ordination with the smaller scale CER. The IEGA suggests the Commission should also adopt these definitions and consider issues for EDBs in relation to these two activities (for example, is low-voltage visibility mostly relevant for CER).

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[14] Page 93 and Footnotes 106 and 107 https://www.mbie.govt.nz/dmsdocument/26909-measures-for-transition-to-an-expanded-and-highly-renewable-electricity-system-pdf

[15] This is an interesting description of why Energy Consumers Australia prefer to say CER: https://energyconsumersaustralia.com.au/news/death-to-der-why-we-need-to-change-the-language-we-use-for-the-energy-transition?mc_cid=d8501bccfb&mc_eid=2f0ba19009

We welcome the opportunity to discuss with you the questions we have raised in this submission and reiterate our request for a meeting with you to discuss the Commission's rationale for changing non-network solutions to non-traditional solutions as well as to understand the Commission's expectations of EDBs in relation to alternatives to network investment.

Nothing in this submission is confidential.

Yours sincerely

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Chris Fincham
IEGA Committee