Submission on *Measures for Transition to an Expanded and Highly Renewable Electricity System*

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Release of information

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Orion Responses to questions

Part 1: Growing Renewable Generation	
1.	**Are any extra measures needed to support new renewable generation during the transition? Please keep in mind existing investment incentives through the energy-only market and the ETS, and also available risk management products. Any new measures should add to (and not undermine or distort) investment that could occur without the measures.**
	No comment.
2.	**If you think extra measures are needed to support renewable generation, which ones should the government prioritise developing and where and when should they be used? What are the issues and risks that should be considered in relation to such measures?**
	No comment.
3.	**If you don't think further measures are needed now to support new renewable generation, are there any situations which might change your mind? When and why might this be?**
	No comment.
4.	**Do you think measures could be needed to support new firming/dispatchable capacity (resources reliably available when called on to generate)? If yes, which kind of measures? What needs do you think those measures could meet and why?**
	No comment.
5.	**Are any measures needed to support storage (such as battery energy storage systems or BESS) during the transition? If yes, what types of measures do you think should be considered and why?**
	We do not make any suggestions about specific measures needed to support storage, but we do note that there will be a need for coordination of the development of new measures or incentives. The Discussion Document refers to various examples in other jurisdictions, such as capacity markets and long-term energy storage service agreements. If some of these approaches were to be adopted in New Zealand, it could significantly impact battery/solar adoption trends or shift the balance in terms of utility scale versus household solar. Potentially these incentives will all drive material changes on the distribution networks and therefore require involvement from Electricity Distribution Businesses (EDBs) during development, testing and deployment. If the government further considers the use of incentives and other mechanisms, we recommend collaboration with FlexForum and ENA to engage with the sector on possible options.

6.	**If you answered yes to question 4 or 5 above, should the support be limited to renewable generation and renewable storage technologies only or made available across a range of other technologies?** **Keep in mind that fossil fuels are generally the cheapest option for firming, though this may change over time as renewable options (particularly batteries) become more efficient and affordable.**
	See question 4 above.
7.	**If you answered yes to question 6 above, what are the issues and risks with this approach? How could these risks and issues be addressed?**
	No comment.
8.	**Are any measure(s) needed to support existing or new fossil gas fired peaking generation, so as to help keep consumer prices affordable and support new renewable investment?**
	No comment.
9.	**If you answered yes to question 8 above, what measures should be considered and why? What are the possible risks and issues with these measures?**
	No comment.
10.	**If you answered yes to question 8 above, what rules would be needed so that fossil gas generation remains in the electricity market only as long as needed for the transition, as part of phase down of fossil gas?**
	No comment.
11.	**Are there any issues or potential issues relating to gas supply availability during electricity system transition that you would like to comment on?**
	No comment.
12.	**Do you agree that specific measures could be needed to support the managed phasedown of existing fossil fuel plants, for security of supply during the transition?**
	No comment.
13.	**If you answered yes to question 12 above, what measures do you think could be appropriate and why? What conditions do think you should be placed on plant operation?** **For example, do you have any views on whether there should be a minimum notice period for reductions in plant capacity, and/or for placing older fossil fuel plant in a strategic reserve?**

No comment.

14. If you answered yes to question 12 above, what are the issues and risks with these measures and how do you think these could be addressed?

No comment.

15. What types of commercial arrangements for demand response are you aware of that are working well to support industrial demand response?

We use various commercial arrangements to manage load. Primarily these are through our distribution charges (i.e. our charges which are set annually for the use of our network).

Of the more than 215,000 connections on our network, approximately 400 are categorised as major customer connections. While major customers make up only 0.2% of our customers by number, they use around one quarter of the total electricity delivered over our network. To qualify as a major customer, a business must have a maximum demand for electricity of at least 150kVA, compared with the maximum electricity demand of a typical house of about 10kVA.[1]

For our major customers, we have a control period demand charge. The value ascribed to this charge reflects our cost to build and reinforce our network to meet peak demand and provide surety of supply. The major customer control period charge is applied to the electricity usage of major customers during what we call 'control periods'. A control period is when our network load is at its extreme peaks, and this may occur between 1 May to 31 August being weather driven.[2] Generally there are only about 60 hours of major customer control period each winter.

We provide signals to tell our major customers that it's a control period so that they can elect to reduce their load, through such means as turning off boilers and freezers and running generators. If a typical major customer responded to Orion's pricing signals by turning off their entire electrical load during control periods, their Orion-related charges for the following year would be reduced by around 40%. Even modest efforts to reduce electrical load during the less than 1% of a year that is a control period can result in significant savings for major customers.

We estimate that of the approximate 140MW of total demand of major customers during our peak demand periods, 20MW of major customer load is reduced as a direct result of this form of pricing (i.e. major customer load shifts from 140MW to 120MW). We expect the amount will increase over time as more coal/diesel process heat load is converted over to electricity.

Major customer connections are split between two control period groups (group 1 and group 2) so that we can stagger the change in load when control periods start and finish. Both groups receive approximately the same incidence and duration of control periods. For the most part, we invoice

[1] Orion's major customer connection category caters for the connections with larger loads and reconciled embedded networks. These connections take delivery in bulk, are able to provide accurate half-hour interval metering data by connection, and generally do not use our low voltage network

[2] See https://online.oriongroup.co.nz/LoadManagement/Default.aspx?autorefresh=false for an up to date view of orion's current loading and load management measurements.

our major customers through their retailers, at the individual ICP level so our control period demand charges are passed on directly to our major customers.

For our general connections (which includes all temporary connections, residential connections and SME connections) we currently have a peak charge (using a dollars / kW / day price) which is based on each retailer's contribution to the peak loading on our network. The peak loading is measured during peak periods that occur during winter (May to August) and are invoiced monthly throughout the year (April to March). Orion provides signals to retailers at the beginning and end of each peak period. This provides retailers with the opportunity to encourage customers to turn off non-essential appliances and other electrical equipment in order to avoid the higher prices charged when the network is heavily loaded. It is up to the retailer as to how they pass on those general connection peak period charges, as these charges are billed to retailers based on a combined aggregate peak for all of their customers.[3]

Another example where pricing is used to encourage demand response relates to the use of irrigators. In our rural network peaks occur during summer months because of the large number of irrigation pumps connected to our network. Orion operates a scheme where we pay rebates to customers who let us interrupt the supply to designated irrigators during a capacity emergency to help us keep the power on for the wider community. (The rebates are paid regardless of whether we actually interrupt supply.) The interruptibility scheme is available for connections with 20kW of irrigation pump capacity or greater. The rebate is based on the size of the load that can be interrupted at the connection. The irrigator must maintain metering equipment at the connection that, at least, records kWh loading levels on a half-hour interval basis.

Together with our other load management tools (our load management primarily focuses on storage water heating, where supply can be interrupted for a period of time without affecting the availability of hot water), and our real-time provision of load management information on our website,[4] we effectively manage network load overall.[5]

16. **What new measures could be developed to encourage large industrial users, distributors and/or retailers to support large-scale flexibility?**

In our experience industrial customers require certainty of the value proposition and as much notice as possible of a requirement to lower load to be able to offer flexible electricity resource. Businesses need to make an assessment of the cost of reducing, or delaying, production of their goods versus the benefits (i.e. value they get from the electricity industry) of lowering electrical demand. To best make this decision high certainty of dollar value and timing is desired.

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[3] See our current Pricing Policy at https://www.oriongroup.co.nz/our-story/pricing
[4] See above n2.
[5] Orion also manages load on behalf of the Upper South Island region EDB group consisting of Orion, Alpine Energy, Network Tasman, Marlborough Lines, MainPower, Buller Electricity, Westpower and Electricity Ashburton. By managing loading on the grid at peak times, the Upper South Island Load Management (USILM) Project has led to a reduction in transmission charges and the deferment of investment in additional transmission capacity. While the USI group maintain a network limit to restrain the impacts of significant fluctuations in peak demand on their networks, there is more often spare capacity in the USI load management. Load management is used in much the same way as for Orion. Typically, on cold winter days load is shed during morning and evening peaks.

There is obvious difficulty in predicting forward what demand on a network or across the electricity system will be, as electricity demand is dependent on a number of factors (e.g. weather, customer behaviour, day of week etc). However, efforts to improve load forecasting, and signalling forward load predictions to industrial customers, are useful. Orion for instance is investigating whether it can implement a day ahead red/amber/green traffic light system into its major customer signalling approach. We would surmise that there may still be uncaptured opportunities to improve forecasting load nationally/locally.

With regard to pricing, aside from making it easier for customers to understand what value is offered by the various players in the electricity industry chain (e.g. wholesale, Transpower, distributors, retailers) for flexibility, it is important for industrial customers to understand the trade-offs between each. For instance, although in theory customers can capture the 'value stack' from the entire industry chain, the reality is that often if a customer is signed up to deliver flexibility to one part of the industry chain, they won't be able to offer that flexibility to another part of the value chain. By way of example, if a distributor is relying on flexibility to defer network investment and has contracted with a customer to deliver that flexibility when the network needs it, that customer will most likely be contractually committed to deliver such flexibility when required – and hence is unlikely to be able to deliver it at other times to other parties.

This inability to access all of the value stack means that industrial players need to be able assess each part of the stack (or offerings from each of the players in the electricity industry chain) against each other in order to determine who best to offer their flexibility to. This points to not only clear identification of the value offered by each player, but also clear identification of timing and terms of the industry player.

New measures to develop large-scale flexibility need to be focused on dollar visibility, timing visibility, and the conflicts between each part of the value stack.

17. **Do you have any views on additional mechanisms that could be developed to provide more information and certainty to industry participants?**

The Government could consider establishing a Flexibility (DER) Resource Register which would provide a repository of distributed generation as well as EV chargers. Visibility of this information will

- aid forecasting of network use and planning,
- streamline switching of retailers/suppliers,
- potentially allow for marketing of products and services, and
- help avoid allocating the same capability twice.

However, we note that this is being considered by the ENA and FlexForum (see step 28 of FlexForum's Flexibility Plan 1.0[6]) and the sector may be best placed to lead this work rather than MBIE. An alternative to the flexibility resource register is for the Electricity Authority's Registry to include more fields specifying DER and/or CER information.[7]

[6] See https://www.araake.co.nz/assets/Uploads/FlexForum-Flexibility-Plan-1.0-31-August-2022.pdf. Also see Australia's DER Register at https://aemo.com.au/energy-systems/electricity/der-register/about-the-der-register

[7] We note that the Electricity Authority has announced that its work programme includes a project to review and update distributed energy resource information requirements captured in the registry database and/or establish a separate distributed energy resource register.

While not a mechanism as such, we also recognise the importance of innovation funding (including innovation allowances, GIDI, and the Community Renewable Energy Fund[8]) in stimulating the development and demonstration of novel mechanisms for new ways of storing and distributing electricity. Forums such as FlexForum and the ENA also play an integral role in the role in advocating and supporting new mechanisms.

In this respect we refer to the ENA's Network Transformation Roadmap[9] which provides information, insights and recommended actions for EDBs to navigate the changes in the way electricity distribution networks will be used in the future. The FlexForum's Flexibility Plan 1.0[10] provides an initial list of the practical, scalable and least-regret steps needed to enable households, businesses and communities to make choices which maximise the value of, and optimise the use of, DER and flexibility.

From a policy perspective, it is imperative for the Energy Strategy to be completed so as all energy participants have clarity as to the "direction of travel".

Part 2: Competitive Markets

18. **Do you agree that the key competition issue in the electricity market is the prospect of increased market concentration in flexible generation, as the role of fossil fuel generation reduces over time?**

Yes, we agree that that the key competition issue in the electricity market is the prospect of increased market concentration in flexible generation. We see two aspects to this:
- Domestic Installations of DER (e.g., private charging points for EV chargers, solar and batteries)., and
- Aggregators to provide flexibility services for short term constraints on networks.

In our view, the first is a disruptor to network power quality and possibly a strain on network equipment, and the latter is a service to relieve constraints where additional electricity will be required to be delivered over time as fossil fuels are phased out.

EDBs are interested in securing adequate funding through capex and opex allowances from the regulators to provide infrastructure which supports the energy transition and reduces constraints, while retailers seek to provide more services to end consumers by offering better pricing structures. The industry needs to work together to get the best outcome for end consumers.

19. **Aside from increased market concentration of flexible generation, what other competition issues should be considered and why?**

We see three other competition issues that warrant consideration:
- Load control where manufacturers limit the ability of flexibility providers to manage any (e.g., wi-fi enabled) load management,

[8] See https://www.mbie.govt.nz/building-and-energy/energy-and-natural-resources/low-emissions-economy/energy-efficiency-in-new-zealand/community-renewable-energy-fund/
[9] See https://www.ena.org.nz/resources/publications/document/483
[10] See https://www.araake.co.nz/assets/Uploads/FlexForum-Flexibility-Plan-1.0-31-August-2022.pdf

- The allocation of responsibilities for load management, especially when a coordinated approach is required to ensure that the network isn't overloaded when load is brought back on-line, eg ripple control and hot water, and
- The use of smart private EV charging stations and where these are installed. Private EV charging stations need to be available on the registry for visibility by industry participants in order to be able to offer off-peak charging pricing as well as any other load control devices.

20. **What extra measures should or could be used to know whether the wholesale electricity market reflects workable competition, and if necessary, to identify solutions?**

EDBs do not trade in the wholesale electricity market as electricity is traded on the NZX between generators and retailers. However, in due course EDBs can assist in offering pricing to connections which supports the use of flexibility services.

21. **Should structural changes be looked at now to address competition issues, in case they are needed with urgency if conduct measures prove inadequate?**

We suggest the following options which could be considered to assist in development of the market. We are not sure whether these amount to structural changes as such but they warrant further consideration:

- Provide better guidance on the role of market participants and third-party aggregators/providers in flexibility services (arm's length non-network solutions),[11] and
- Ensure that the registry provides sufficient meaningful information across all industry participants to provide flexibility and smart appliance management to shift peak loads via better pricing options offered to customers.[12]

22. **Is there a case for either vertical separation measures (generation from retail) or horizontal market separation measures (amending the geographic footprint of any gentailer) and, if so, what is this?**

No comment.

23. **Are measures needed to improve liquidity in contract markets and/or to limit generator market power being used in retail markets? If yes, what measures do you have in mind, and what would be the costs and benefits?**

Yes. Industry participants should be acting in the best long-term interests of consumers and not extracting excess profits for a utility service. Retailers and generators should have an obligation to provide certain annual financial information to the regulators to ensure that the market is operating efficiently and cost effectively and not only rely on the spot market prices.

[11] We note that the Electricity Authority has announced a new project to consult on bringing flexibility providers into the Code to improve visibility and coordination between participants. See Delivering key distribution sector reform (ea.govt.nz) .

[12] The Electricity Authority has also announced a new project to review and update distributed energy resource information requirements captured in the registry database (eg, functionality, batteries, electric vehicle chargers), and/or establish a separate distributed energy resource register.

24.	**Should an access pricing regime be looked at more closely to improve retail competition (beyond the flexibility access code proposed by the Market Development Advisory Group or MDAG)?**
	We agree with MDAG that increasing market concentration of flexible generation sources will help competitive pricing of services. The flexibility market is very much in its infancy especially as to how we separate network based (non-traditional solutions) and what can be offered in the flexibility services market. No further comment, as Transpower and EDBs prices are passed through by retailers to the end consumer.
25.	**What extra measures around electricity market competition, if any, do you think the government should explore or develop?**
	No comment.
26.	**Do you think a single buyer model for the wholesale electricity market should be looked at further? If so, why? If not, why not?**
	No (unless it was a government-controlled market and priced according on a cost to serve basis which is not necessarily an efficient alternative). The market is structured in a similar way to Australia and the UK, and it appears to be operating as intended. New Zealand did not see significant price increases during the pandemic and gas crisis in recent times like the UK and Europe.
Part 3: Networks for the Future	
27.	**Do you consider that the balance of risks between investing too late and too early in electricity transmission may have changed, compared to historically? If so, why?**
	We agree that the balance of risks between investing too late and too early in electricity has changed. We think the balance has shifted in favour of bringing projects on line early. We are concerned that that projects that come on line too late will delay electrification or investment in new generation, the same applies for the distribution networks.
28.	**Are there any additional actions needed to ensure enough focus and investment on maintaining a resilient national grid?**
	No comment.
29.	**Do you agree we have identified the biggest issues with existing regulation of electricity distribution networks?**
	Yes, although the issues as written do not capture fully some of the concerns. ***Network investment model to support energy transition*** - To ensure that electricity distribution networks can support growth and variability of demand and supply, it is **imperative** that the

Government gets the regulatory settings right for the electricity distribution sector. As the Climate Change Commission's draft 2023 *Draft advice to inform the strategic direction of the Government's second emissions reduction plan* notes (emphasis added)[13]

> *Lines companies have a critical role in managing peak demand and delivering services for the long-term benefit of consumers. The regulatory system needs to provide the appropriate incentives for lines companies to manage peak demand through existing tools and to invest in other ways to manage demand, such as through batteries, distributed energy resources, or network reinforcement.*
>
> *Uncertainty about future requirements and potential solutions has increased. The existing regulated investment framework for transmission and distribution infrastructure needs to be future proof by looking to meet outcomes related to emissions reduction, system security and reliability, and affordability.* ***Expenditure forecasting approaches and allowable revenues for lines companies need to be able to support the accelerated pace of investment in generation and electrification that is required.*** *Physical grid capacity must keep pace with generation build. Control and operation of the grid also needs to evolve as generation becomes more distributed and digitisation increases.*

As you will be aware, the current default price quality path for electricity distribution businesses (DPP3) is due to expire on 31 March 2025. The Commerce Commission must make a decision on the next default price-quality path to apply (DPP4) by 30 November 2024. As we see it, DPP4 will be critical to our decarbonisation journey. Without the appropriate level of authorised expenditure EDBs subject to price quality control will not be able to appropriately plan or provide for the electrification needed for decarbonisation. Key to the reset of the DPP4 will be the forecast expenditure of EDBs. EDB expenditure is forecast to rise given the imperative to decarbonise and deliver new services.[14] It is therefore absolutely essential that these settings are right for future network investment.[15]

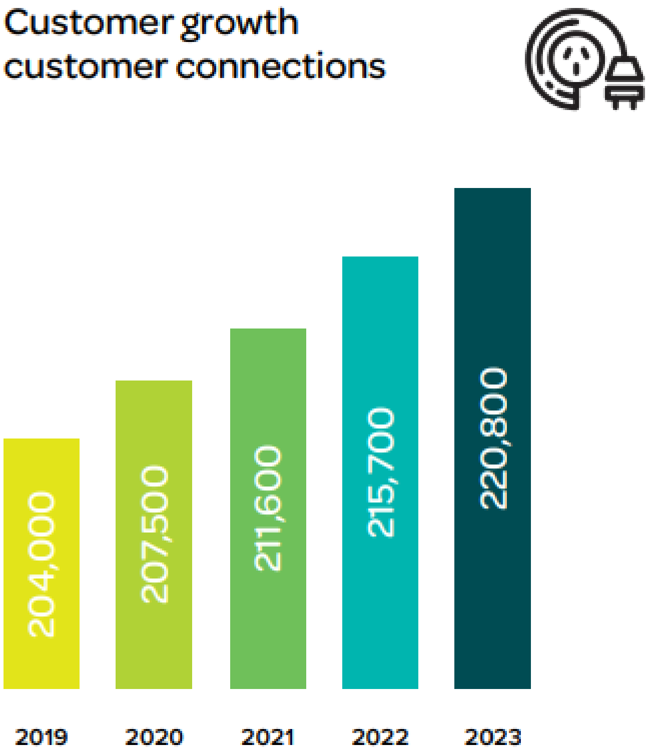
The Discussion Document notes that the regulatory environment does not currently provide adequate flexibility to respond quickly to changing circumstances. We agree. By way of example, EDBs experience of current reopener provisions is that the process limits our ability to respond to our environment in an agile way - the Commission's own resourcing can mean up to 9 months before substantial responses/decisions following application. There may also be challenges with applications later in the regulatory period as the decision may cross over into the next regulatory period.

Furthermore, the current regulatory model does not provide sufficient incentives for EDBs to deploy opex solutions (such as flexibility services) over traditional capex alternatives where these are lower cost.

These are the types of issues that are time and resource intensive and do not allow us to respond quickly to changing circumstances.

[13] See pages 114 to 115.
[14] By way of example see the forecast expenditure of Orion in our Asset Management Plan at https://www.oriongroup.co.nz/assets/Our-story/Publications/Orion-AMP-2023.pdf
[15] This includes the financeability issue which needs to be addressed in reset decisions so that we have a workable debt approach.

Removing barriers to connection for new demand – Yes, we agree that there are some barriers to connections for new demand (such as inconsistent distribution policies, processes and capacity and constraints imposed by regulation) across the sector. However, we have had a record number of new connections in the last few years as illustrated below. We have also improved our connection process to make it more user friendly for customers.



We discuss this further at question 33.

Pricing signals to provide efficient use of networks - Our goal, every pricing year, is to set prices that signal the efficient use of our electricity distribution network for the long-term benefit of consumers.[16] We also aim to reduce retailer transaction costs, and in recent years we have introduced a range of changes to simplify the application of our pricing. However, whether or not our pricing is relayed to the customer is dependent on the approach of each retailer.

As an additional comment, we note that in the future as flexibility markets develop, the underlying distribution pricing may not impact the retail tariff but it could impact the automated control of DER. If this eventuates, we do not necessarily need the retail charges to directly reflect distribution pricing, but the distribution pricing will need to be an input into the optimisation algorithm.

30. **Are there pressing issues related to the electricity distribution system where you think new measures should be looked at, aside from those highlighted in this document? How would you prioritise resolving these issues to best enable the energy transition?**

[16] See https://www.oriongroup.co.nz/assets/Our-story/Pricing/Orion-pricing-methodology-history-2023.pdf

In our view, a very real pressing issue is workforce capacity and capability. In terms of new jobs, we refer to the recent report from the Boston Consulting Group *The Future is Electric A Decarbonisation Roadmap for New Zealand's Electricity Sector*. That report refers to estimates by Contact Energy that a more renewable based energy market could support 350 new permanent jobs and 7,500 construction jobs over the next 10 years.[17] The Boston Consulting Group also notes that the skills and composition of those employed within the sector will also change as the technologies deployed across the system vary and the functions of various participants within the system change. There is going to be a growing need, amongst other things, for construction managers and EV infrastructure engineers.

In the International Energy Agency's report *New Zealand 2023 Energy Policy Review,* it noted that

> *"To advance energy efficiency strategies, the government should ensure sufficient capacity and skills to deliver on projects. As in other countries, the scale of upcoming energy efficiency upgrades to meet decarbonisation plans will require a significant expansion of skilled workers across the sector. As the government pursues a new NZEECS and decides on budgetary outlays, specialty skills training in the energy efficiency space should be given due consideration."*[18]

31. **Are the issues raised by electricity distributors in terms of how they are regulated real barriers to efficient network investment?**
Please give reasons for your answer. Is there enough scope to address these issues with the current ways distributors are regulated? If not, what steps would you suggest to address these issues?

Electricity Distributors are regulated because they are natural monopolies. The regulatory framework requires flexibility to reduce, but not entirely eliminate price shocks to end consumers. For example, the delay in compensation in the 5-year (e.g. DPP3 2020-2025) regulatory cycle provides certainty for consumers in prices but creates limitations on investment by EDBs (capex vs opex). However, more agility in the framework would allow the Commission more scope to set reopeners and allowances which better support investment and EDBs to respond more appropriately.

32. **Are there other regulatory or practical barriers to efficient network investment by electricity distributors that should be thought about for the future?**

The regulators have defined the allowances and re-openers and proposed large connection contracts which can be negotiated outside of the regulatory framework. While this will support decarbonisation we are still concerned that these are only for major entrants. They will not support mass adoption by smaller energy consumers, which over time can have a large impact on electricity demand.

Although not regulation as such, one practical barrier to efficient network investment is that network companies do not have visibility of homes with EVs. Although registry changes could

[17] See page 197 and also Contact Energy's report "*Crafting a path for New Zealand's 100% renewable electricity market*", p 12.
[18] See https://iea.blob.core.windows.net/assets/124ce0b0-b74e-4156-960b-bba1693ba13f/NewZealand2023.pdf , page 63.

enable the identification of homes with smart chargers, EECA has identified that over three quarters of home EV charging is via three pin plugs. For network investment decisions to be better optimised, networks should be able to access registration information to see the address that EVs are registered against. This would provide networks with a much better idea of where EVs are charging and low voltage impact. The present position of the relevant government department(s) is that such information cannot be released to network companies and flexibility providers – we would suggest this issue could be considered by MBIE.

33. **What are your views on the connection costs electricity distributors charge for accessing their networks? Are connection costs unnecessarily high and not reflective of underlying costs, or not? If they are, why do you think this is occurring?**

EDBs do not deliberately create barriers to slow down new connections, and connections range in complexity, cost, scale, and capacity requirements. Essentially, "the costs are the costs" for a connection and different EDBs will have different requirements and different approaches as to recovering costs as between new and existing customers.

Generally, we have a number of considerations to take into account when assessing the requirements to connect a customer, these range from the distance from the point of supply, capacity, utilisation, maximum demand, and overall energy consumption to establish the investment required.

Orion has recently undergone a review of the methodology applied to connection pricing, following a period of a more subsidised approach when rebuilding the city post-earthquake. We acknowledge that our methodology as we transition to a new period of decarbonisation and electrification, required consideration, and we have been working on updating the connections pricing methodology. We consider our new methodology to connections pricing will be more efficient in the current context. Orion's approach is to ensure that the balance between existing customers and connecting customers is appropriate e.g., existing customer do not face higher charges (now or in the future) solely due to new connections to the network.

Taking a national view, these considerations may differ from region to region (across EDBs) as different regions will have different characteristics.

Furthermore, it depends on the amount of investment which the regulators allow distributors on their ability to fund the connection, when assessing the customer contribution of connection costs.

34. **If you think there are issues with the cost of connecting to distribution networks, how can government deliver solutions to these issues?**

The government could look at standardising terminology, processes, and approaches for connections. This would have value to access seekers to fairly evaluate connection pricing across networks when making investment decisions or investing across networks (nationally or across a number of regions).

Please refer to our submission to the Electricity Authority on the Targeted Reform of Distribution Pricing and the answer to question 23.[19]

35. **Would applying the pricing principles in Part 6 of the Code to new load connections help with any connection challenges faced by public EV chargers and process heat customers? Are there other approaches that could be better?**

No comment.

36. **Are there any challenges with connecting distributed generation (rather than load customers) to distribution networks?**

As a general comment, there are no particular challenges with the actual connection of distributed generation to distribution networks. Technical issues are resolved and the connections are made. However, there is challenge with how we charge for connected distributed generation. For example, residential customers who export electricity (solar) to the local distribution network are using the network assets and it is difficult to apportion the recovery of the network costs to these customers.

Furthermore, Part 6 of the Electricity Industry Participation Code is not well suited to dealing with multiple types of allocations ranging from residential solar connections to large generation plants. We made a submission on Part 6 to the Electricity Authority earlier this year.[20]

37. **Are there different cost allocation models addressing first mover disadvantage (when connecting to distribution networks) which the Electricity Authority should explore, potentially in conjunction with the Commerce Commission?**

There needs to be consideration of the implications of any changes that impact EDB's capex or opex allowances (set by the Commerce Commission) and the mix between these (especially around connection charges) given the limited ability to reopen a 5-year price path. Orion supports a collaborative educational approach that ensures that there is a baseline expectation regarding behaviour and allocation of connection costs. Orion would support the Commerce Commission being involved in any change that materially impacts costs faced by EDBs and consumers, including connection costs.

38. **Should the Electricity Authority look at more prescriptive regulation of electricity distributors' pricing? What key things would need to be looked at and included in more prescriptive pricing regulation?**

No. It is not advisable to be too prescriptive, as it may impact electricity consumers negatively in some areas of a distributors network, specifically more remote areas if these costs are not properly socialised, making it unaffordable to certain customers. In addition, different distributors have

[19] See https://www.oriongroup.co.nz/assets/Our-story/Submissions/EA/Cover-letter-on-targeted-reform-of-distribution-pricing-issues-paper-Aug-2023.pdf and https://www.oriongroup.co.nz/assets/Our-story/Submissions/EA/Orion-submission-issues-paper-distribution-pricing-appendix-G-July-2023.pdf

[20] See https://www.oriongroup.co.nz/assets/Our-story/Submissions/EA/EA-feedback-on-issues-paper-updating-the-regulatory-settings-for-distribution-networks-Mar-2023.pdf

differing challenges on their networks and cost reflective pricing should support their cost structures.

39. **Do current arrangements support enough co-ordination between the Electricity Authority and the Commerce Commission when regulating electricity distributors? If not, what actions do you think should be taken to provide appropriate co-ordination?**

Appropriate coordination could be achieved with one specialist energy regulator rather than two. There is a double up of functions and oversight. This is clear from the amended section 32 of the Electricity Industry Act 2010, and the benefit of having two regulators is not necessarily clear.

40. **Will the existing statutory objectives of the Electricity Authority and Commerce Commission adequately support key objectives for the energy transition?**

The statutory objectives of the Commerce Commission and Electricity Authority are clearly defined **but** not in relation to the key objectives of the energy transition.[21] In Orion's view, it is not clear whether the existing statutory objectives will support the objectives of the energy transition. To read them in a supportive way, you must imply emissions reduction goals and the like into the current objectives.

Furthermore, it is unsatisfactory for there to be confusion about the effect of section 5ZN of the Climate Change Response Act 2002 in relation to the Commerce Act 1986 and the Electricity Industry Act 2010. (The Commission's current position is that that may take into account the section 5ZN considerations provided they are relevant and that doing so does not compromise their achievement of the section 52A purpose of Part 4 of the Commerce Act.)

A recent example where Orion found that the existing statutory objectives did not support the energy transition occurred when Orion applied for an innovation allowance to support our carbon offsetting programme.[22] The basis of our application was that our innovative approach to achieving carbon neutrality met the purpose of "*delivering electricity lines services at a lower cost to consumers and at a higher quality of supply to consumers*". However, the Commerce Commission declined this application, one of the reasons being that voluntary carbon offsetting falls outside the regulated electricity lines service defined under s 54C of the Commerce Act 1986.[23] Whilst this did not specifically engage section 52A of the Commerce Act, we consider that had section 52A had a specific objective relating to emissions reduction targets and plans there would have been scope for this project to have been considered favourably.

41. **Should the Electricity Authority and/or the Commerce Commission have explicit objectives relating to emissions reduction targets and plans set out in law? If so,**
- **should those objectives be required to have equal weight to their existing objectives set in law?**
- **why and how might those objectives affect the regulators' activities?**

[21] Assuming that the objectives are the four high level objectives of the Energy Strategy.
[22] See https://comcom.govt.nz/__data/assets/pdf_file/0029/279722/Orion-Innovation-Allowance-Application-June-2021.pdf
[23] See https://comcom.govt.nz/__data/assets/pdf_file/0030/279723/Commission-response-to-OrionE28099s-Innovation-Allowance-Application-15-November-2021.pdf

Orion's Chair, in our Annual Report 2023, reinforced the changes and challenges which we are seeing in the electricity sector:[24]

> *"There is a growing consensus on the importance of the electricity sector for Aotearoa New Zealand's future and this has heightened the Orion Group's focus on where we need to be to meet our community's needs in a fast-evolving landscape.*
> *The increased urgency to decarbonise our economy, climate change precipitating severe weather events across the motu and sustained customer growth in our region have prompted us to refresh our strategy and make a step-change in our network investment plans. Globally many countries face significantly larger challenges than we face in Aotearoa New Zealand however we can't let this relative advantage create complacency – we need to act now to ensure that we can deliver a sustainable future*."

Orion's Chief Executive also noted that

> *"Decarbonisation is one of the biggest mega trends of our lifetime. As steward of the electricity distribution network serving Aotearoa's second largest city and fastest growing district, Orion has a critical role to play in delivering New Zealand's decarbonisation objectives."*

In light of these comments, yes, the appropriate approach is to clearly state the objectives of each regulator in legislation. This should include explicit objectives relating to emissions reduction targets and plans. We agree with the approach being adopted in Australia whereby the National Energy Objectives (NEO) (which are contained in federal statutes) will explicitly refer to the achievement of targets for reducing Australia's greenhouse gas emissions or be likely to contribute to reducing Australia's greenhouse gas emissions.

We also agree with the Australian approach which will provide that the emission reductions objective will be one of several objectives (alongside, price, quality, safety, reliability and security of supply) that the Australian Energy Regulator will be obliged to consider and will have discretion to balance in making its decisions.[25] Therefore having equal weight to other objectives that are set out in law.

42. **Should the Electricity Authority and/or the Commerce Commission have other new objectives set out in law and, if so, which and why?**

No comment.

43. **Is there a case for central government to direct the Commerce Commission, when dealing with Electricity Distributors and Transpower, to take account of climate change objectives by amending the Commerce Act and/or through a Government Policy Statement (GPS)?**

[24] See https://www.oriongroup.co.nz/assets/Our-story/Publications/Orion-Group-Annual-Report-2023.pdf
[25] See https://www.aer.gov.au/system/files/AER%20-%20Guidance%20on%20amended%20National%20Energy%20Objectives%20-%20Draft%20guidance%20-%20July%202023%20%281%29.pdf

No. We do not agree with the section 26 approach (or an approach that relies on section 17 of the Electricity Industry Act 2010 with regard to the Electricity Authority). We do not think Government Policy Statements should be used as a substitute for a legislative amendment. Given the importance of the issue, we do not consider this to be a satisfactory approach.

44. **If you answered yes to question 43, please explain why and indicate:**

- **What measures should be used to provide direction to the Commerce Commission and what specific issues should be addressed?**
- **How would investment in electricity networks be impacted by a direction requiring more explicit consideration of climate change objectives? Please provide evidence**.

Although we answered "No" to question 43, we consider that a similar approach to Australia with the National Energy Objectives is the best approach in this case.

In our view, investment in electricity networks will be positively impacted by a direction requiring more explicit consideration of climate change objectives. It will effectively require regulators to apply a value to emissions reductions to inform regulatory decisions. This will potentially allow an approach to regulatory funding where an uplift will be permitted for decarbonisation.

Part 4: Responsive Demand and Smarter Systems

45. **Would government setting out the future structure of a common digital energy infrastructure (to allow trading of distributed flexibility) support co-ordinated action to increase use of distributed flexibility?**

We refer you to the FlexForum Insights document "*A digitalised electricity system is needed for flexibility to fully play its part in electrification and decarbonisation*"[26] which notes as follows:

> *"Households, communities and businesses are starting on an electrification journey resulting in the proliferation of electric vehicles (EV), EV charge points, local generation, battery storage, electric space and water heating, electric motors and other smart devices. These DER will need to be seamlessly integrated into the networks, electricity system and market in a way that gives opportunities to provide additional value to their owners, while preserving the security and reliability of the physical networks for all consumers.*
>
> *Digitalisation must be at the heart of this integration to deliver the information needed to balance the electricity systems required to keep the lights on from second-to-second, across seasons and for planning years ahead. This information also enables households, businesses and communities to make choices about electrification and their level of participation in the electricity markets, including the choice to invest in and supply flexibility."*

It is important that the government starts thinking about the future structure of a common digital energy infrastructure but our submission is that any work in this area should be carried out in conjunction with industry participants such as the FlexForum and ENA's Future Networks Forum which plays a role in research and collaborative innovation between EDBs.

[26] See at https://www.linkedin.com/company/flexforum/posts/?feedView=all

The approach used to develop the System Flexibility Exchange (SFE) proposed by Ofgem in the call for ideas started with identifying use cases and the functionality required by the marketplace. An important use case to consider will be distribution flexibility services. While these are starting to mature in the UK following years of innovation funded trials and continuous improvement stimulated by the RIIO-2 regulatory framework, market provided flexibility services are nascent in New Zealand, with Orion being one of 4 EDBs to tender for these and only one EBD (Aurora) having operationalised these. Orion will operationalise its first market provided flexibility service in 2024.[27]

While insights can be taken from overseas, it will take considerable time and effort to develop the processes, systems and capability to implement these in NZ. To effectively design an SFE, a necessary prerequisite is to consistently define procured flexibility services for EDBs, alongside any other use cases for flexibility markets. This is already underway due to efforts by specific EDBs, the ENA, FlexForum and EEAs FlexTalk project. We strongly advocate for MBIE to support these collaborative efforts, including the development of aligned solutions that may not be considered entirely 'novel' to inform any common digital energy infrastructure design requirements.

46. **Should central government see how demonstrations and innovation to help inform how trade of flexibility evolves in the New Zealand context, before providing direction to support trade of distributed flexibility? If yes, how else could government support the sector to collaborate and invest in digitalisation now?**

Yes. We have previously suggested that the Government (the Electricity Authority) takes a similar approach to the UK and allows the market to evolve through exploration, and an industry led convergence before standards and legislation are implemented.

Engaging with industry workgroups such as the ENA and FlexForum will de-risk the Government's potential of prematurely setting regulation incorrectly. Predetermining how the market may evolve and prematurely forming regulations will restrict innovation, future flexibility and not provide time to design appropriate regulations suitable for New Zealand.[28]

That said, government support to encourage collaboration and investment is imperative, and there are some steps which the government could continue to take or introduce without an overarching reform piece.

For example, we acknowledge MBIE's endorsement and financial support of the FlexForum which is a key factor in building broad support for FlexForum's collaborative approach,[29] and ask that this support is continued. Without this and other collaborative forums like the ENA coordinating activity, development of flexibility opportunities will be siloed, inconsistent and slow. In addition to stimulus for innovation, support for the development and deployment of aligned solutions and processes would also be beneficial.

One specific area where government reform will encourage investment is better access to, and visibility of, electricity information. The Electricity Authority's consultation on the issues paper "*Updating the Regulatory Setting for Distribution Networks*" specifically looked at equal access to data and information. In particular, the Authority considered access to historical non-aggregated

[27] See https://www.oriongroup.co.nz/your-energy-future/innovation

[28] See our submission to Electricity Authority on Updating the Regulatory Settings for Distribution Networks, above n 20.

[29] See https://www.linkedin.com/company/flexforum/posts/?feedView=all FlexForum Insights "*Agile change processes are needed to enable flexibility and accelerate electrification*".

ICP-level Consumption Data and Power Quality data, visibility of location, size, and functionality of (non-exporting) Distributed Energy Resources (DER) installed on LV networks, real-time non-aggregated Consumption Data and Power Quality Data. The Authority asked about the priority that should be given to this data.

Our view is that high priority needs to be given to at least the first two aspects of this data. Especially, to enable DER visibility as this is not easy to predict and forecast. Lack of access to this data this could impact public trust and slow down investment in decarbonisation. It is important that we remain ahead of the 'S curve' of technology adoption as it takes time to procure flexibility services and implement network upgrades.[30]

47. **Aside from work already underway, are there other areas where government should support collaboration to help grow and develop flexibility markets and improve outcomes? If yes, what areas and actions are a priority?**

We refer to our comments at question 46 above about funding and collaboration with FlexForum and the ENA.

In our view innovation funding assistance is a priority. While collaborating can reduce the individual contribution each network needs to make to address these steps, developing a common solution is more resource intensive and complex. In addition to innovation funding, having some co-funding for the energy industry to develop collaborative solutions would be hugely beneficial (FlexTalk is a good example of how this can work).

The Discussion Document at para 313 and footnote 119 refers to the Open Networks programme in the UK. We agree that this has worked well in the United Kingdom and we think that the Open Networks programme is similar to the current work of FlexForum and the ENA. This type of programme could work well in New Zealand if appropriately resourced.

48. **Could co-funding for procurement of non-network services help address barriers to uptake of non-network solutions (NNS) by electricity distributors?**

Despite our comments at question 47, we do not support co-funding for procurement of non-network solutions (NNS). The barriers to the uptake of NNS by electricity distributors are driven by other systemic issues such as delays in addressing the availability of data and the regulation of smart devices. In our view, it would be better to address these systemic issues rather than look at co-funding in the first instance. We explain more below.

In addition to the barriers mentioned in paragraph 315 of the Discussion Document, a notable challenge to NNS is the difficulty in accurately forecasting how much flexibility is needed, how to structure the service and how long to contract. As the lead time for a network solution must be allowed for when exploring a NNS solution (in case it is not viable) there can be significant uncertainty in growth scenarios and therefore the flexibility service required.

These factors have a significant impact on the cost of flexibility and can be very demanding for EDB staff to accurately evaluate options. Many networks are working on improving network visibility,

[30] We note that the Electricity Authority has announced a project to develop a Code amendment proposal to enable meter equipment providers to contract directly with distributors and flexibility traders to provider connection point data. See Delivering key distribution sector reform (ea.govt.nz)

maturing their planning forecasts and scenarios, and developing modelling capabilities which will make identification of flexibility opportunities more robust. Additionally, networks who have procured NNS are sharing processes, procedures and lessons to support each other in adopting these and building capability across the sector.

EDBs and flexibility suppliers need support to be able to develop and test scalable NNS solutions in a safe to fail environment e.g. where there is not an operational risk or service level implication if the solution fails. By 2020, networks in the UK had run over 138 projects related to flexibility with a combined value of £330 million. The number and value of projects has increased steadily overtime. Initially the focus was on investment planning and system operation (enablers – similar to NTI roadmap). However, increased focus on service optimisation and charging (commercial relationships and pricing) overtime as market-led models has now emerged.

One example of project that is investigating NNS is “Resi-Flex”. The project aims to incentivise flexibility from residential consumers by exploring commercial mechanisms in collaboration with flexibility stakeholders. Building on connections through the FlexForum, Orion and Wellington Electricity partnered on the project to drive progress, leverage shared resources and expertise, and develop scalable insight. The workstreams for the project are as follows:

Resi-Flex started by understanding the requirements of all users across the value chain for flexibility from consumers to flexibility stakeholders, to distribution network companies. This is informing the development of commercial mechanisms that could incentivise greater use of flexibility resources in the future. During the next stage of Resi-Flex, we intend to partner with flexibility stakeholders to co-design and trial customer offerings that encourage household flexibility, underpinned by the commercial mechanisms. Lastly, we will consolidate learnings and establish recommendations to support the implementation or scale of successful insights or approaches.[31]

This is the type of collaboration that needs to be supported and encouraged. Resi-Flex is providing insight on residential flexibility to inform the design of trials and supports steps in the FlexForum’s Flexibility Plan. The trials will inform the effectiveness of different solutions and which ones to scale. Ultimately, this will create opportunities for residential consumers to provide flexibility, while supporting equitable outcomes for all consumers.

49. **Would measures to maximise existing distribution network use and provide system reliability (such as dynamic operating envelopes) help in New Zealand? If yes, what actions should be taken to support this?**

[31] See https://www.oriongroup.co.nz/your-energy-future/innovation

Yes. There is no silver bullet to maximising existing distribution network use and providing system reliability. Any actions should be taken across the following two forms:

1) Ensure any transition from existing to alternative DSF mechanisms is well managed, and
2) Support the exploration of new mechanisms.

Key to these actions is ensuring that EDBs have adequate revenue (as discussed at question 29) and the regulatory environment allows for these types of actions.

Ensure any transition from existing to new demand side flexibility mechanisms is well managed

Ripple management of hot water

One long standing way Orion reduces our peak loads is through financial encouragement for residential customers to only heat their hot water cylinder overnight or to allow us to briefly stop them from heating their cylinder when we are experiencing short term peak demand conditions. We estimate our peak load is reduced by around 150MW from these interventions. Without this, our peak load would increase from around 650MW to 800MW – around 15% more. Currently hot water control is achieved through Orion owned ripple control signalling plant. Ripple systems are a cheap and effective means to control network and transmission peaks. Essentially, by using ripple, we have been able to defer capex, and it has provided considerable benefit to Orion and its customers by deferring expenditure.

However, we note that ripple does not easily allow an individual retailer the flexibility to reduce the hot water load of their particular customers when that individual retailer may want it to occur, any time of year. Consequently, it is possible that in the future many customers' hot water load will switch from being operated by ripple plant to being operated by technology within the customer's smart meter. This will then allow the hot water system to be more easily controlled for purposes other than network demand management, such as when it's most financially rewarding for the customer and/or the customer's retailer from a market price perspective. For most periods of time there is likely to be alignment between the desire to control hot water by retailers and distributors. However, there will be times when this is not the case.

This means that unless regulations establish some sort of priority order for management of hot water via smart meters, on cold winter days we are unlikely to be able to reliably draw on all available hot water systems to reduce our peaks[32] as retailers may want to control them at different times in that day. Consequently, there is a risk of peak network demand increasing because of system-wide coordination risk. This means our network will need to be built bigger. Given the level of capacity deferral current ripple management affords this **cannot** be achieve in a short space of time and will require **significant investment**.

We are keen to ensure that the development of flexibility markets does not sacrifice the benefits in place already with the current hot water load control mechanism. However, we appreciate that no one solution will suit all EDBs and EDBs use hot water control differently. It also depends on the availability/penetration of smart meters. Customers get benefits from hot water control in different ways, and a nationwide approach may mean that some customers are not served as well as others by changes to hot water control. In any event, there needs to be some recognition that uncontrolled load forecasts will become inaccurate when visibility of system DER management is not available. Furthermore, there is the potential for a lack of coordination and confidence when a response is

[32] This was used in Winter 2023 by the System Operator.

required, including for the System Operator, if EDBs do not have adequate visibility and management of hot water, especially when there is an emergency situation.[33]

We see various actions that can be taken to manage the risks around hot water control. For example -

- Ensure customer service levels are protected from the impact of shared control e.g. cold "hot water" is not an option,
- Protect against secondary peaks when load is restored, and
- Mitigate operational, planning and commercial issues due to rapid demand changes resulting in unaffordable and rapid network investment.

Network planning
Enabling greater visibility of the LV network (for example, see our comments at question 46 about the access to information) supports -

- Dynamic asset rating - limits on based profiles or temperature,
- Identification of weaker LV network areas and reinforcement to current design standard e.g. match solar and/or future car charging,
- Capacity rebalance between neighbouring transformers, and
- Phase balancing in LV circuits.

The focus here must be a coordinated transition to prevent unintended consequences which could result in the removal of the social licence to embark on these reforms.

Support the exploration of new mechanisms

Supporting the exploration of new mechanisms will require MBIE's support for greater network visibility and innovation. The Electricity Authority and the Commerce Commission should also explore how to design markets and mechanisms (including distribution pricing) to achieve whole of system value. (This could mean distribution networks building more capacity to avoid curtailment of renewables which could be the right whole of system outcome but not the optimal outcome for EDBs). Other new mechanisms might be -

- Flexibility management -
  - Encourage energy efficiency and influence behaviour (shape approach)
  - Store surplus energy and smooth peaks (shift approach)
- Dynamic operating envelopes, including
  - National standards for calculating DOE
  - Capacity allocating methods to meet social expectations of "fairness" – this came out of Australia's project Edge.

50. **What do you think of the approaches to smart device standards and cyber security outlined in this document? Are there other issues or options that should be looked at?**

[33] In the future, MBIE/Electricity Authority may need to look at the role of the Default Distributor Agreements and whether these should be extended to include aggregators, other technologies and to more explicitly specify the enabling role and necessity of hot water management via ripple in grid and distribution security (for instance preventing an outage in an emergency). Distributors need to maintain adequate visibility and management of hot water. However, retailers and networks may be able to develop and agree protocols to coordinate between retailer/EDB use of hot water loads in time. Similar provisions will be needed for other devices.

We have previously submitted on smart device standards for EV chargers.[34] We also submitted on the Government's Discussion Document on the resilience of New Zealand's critical infrastructure.[35]

New smart technologies like automation, AI, Internet of Things (IoT), real-time communication, and network visibility by household will revolutionise the way electricity systems are operated. As technology improves and the cost of IoT sensors decline, it is likely that millions of distributed energy resources will be able to interact in real-time with the electricity system. This provides a significant opportunity to increase consumer participation in markets and allow consumers to make choices that better suit their needs. However, it will also introduce new vulnerabilities.

We would urge the Government to progress its reforms in this area.

51. **Do you think government should provide innovation funding for automated device registration? If not, what would best ensure smart devices are made visible?**

Yes, the Government should provide innovation funding for automated device registration.

52. **Are extra measures needed to grow use of retail tariffs that reward flexibility, so as to support investment in CER and improved consumer choice and affordability?**

Retail tariffs should recognise distributor pricing so that consumers can efficiently use the network in accordance with the incentives and price signals promoted by distributors.

53. **Should the government consider ways to create more investment certainty for local battery storage? If so, what technology should be looked at for this?**

No comment.

54. **Should further thought be given to making upfront money accessible to all household types, at all income levels, for household battery storage or other types of CER?**

Targeted funding for CER may be an effective mechanism to address energy hardship and risk increasing inequity, as higher income households and communities access the benefits of CER, while low income and vulnerable households get left further behind.

55. **Should government think about ways to reduce 'soft costs' (like the cost of regulations, sourcing products, and upskilling supplier staff) for installing local battery storage with solar and other forms of CER/DER storage? If so, what technology should be looked at?**

[34] See our submission to ECCA on Improving the performance of electric vehicle chargers at https://www.eeca.govt.nz/assets/EECA-Resources/Consultation-Papers/EV-charging-green-paper-submissions-part-1.pdf, p94.

[35] See https://www.oriongroup.co.nz/assets/Our-story/Submissions/Other/Orion-submission-on-strengthening-resilience-critical-infrastructure-Aug-2023.pdf

No comment.

56.	**Is a regulatory review of critical data availability needed? If so, what issues should be looked at in the review?**

Please see our answer to question 46 and also refer to our submission on the Authority's Issues Paper "*Updating the Regulatory Settings for Distribution Networks*".[36] We also refer to the recently released work programme of the Electricity Authority.

Part 5: Whole-of-system considerations

57.	**What measures do you consider the government should prioritise to support the transition?**

We ask the government to prioritise these matters to support the transition:

- Getting the regulatory settings right for the price quality regulation of EDBs to enable the scale and type (opex vs capex) of investment needed to support the transition to a decarbonised and resilient future system. We refer to this at question 29. This also includes addressing the financeability question in the next reset so that EDBs have a workable debt approach.
- Identify and action the tasks needed to enable a significant increase in the skilled workforce that is needed by EDBs and others in the energy sector to deliver the energy transition.
- Collaborate to explore and evolve roles and functions to enable the transition towards a 100% renewable, distributed and flexible energy system.
- Access to consumption and electricity quality data for the low voltage network must be supported and actioned as soon as possible. This is needed to improve the visibility of the low voltage network and support flexibility services.[37] We note the current work programme of the Electricity Authority in this respect.
- There needs to be sufficient regulatory leeway to allow for "learning by doing" in order to enable flexibility (as this will be key part of managing load to defer or prevent capex spend). This will enable the market to decide the most appropriate solutions. (Again, we note that Electricity Authority has identified that it intends to produce guidelines on conditional Code exemption process to support regulatory 'sandboxes' and trials. The guidelines should be available for release in early 2024.)
- Recognise and support the importance of local area energy planning (especially for EDBs and local authorities) for an optimised transition. The government must support community conversations about local energy needs. This includes deeper engagement with customers of all scales to ensure the opportunities to provide demand side flexibility and the value of this to consumers is understood as consumers look to decarbonise their own activities and leverage market opportunities to support the energy transition.

[36] See above n20.

[37] We note that recently we have signed an agreement with a metering provider that will see us obtain critical network operational data, on a 5-minute historic basis, for around 90% of the smart meters on our network. Other EDBs may however still be struggling to negotiate for receipt of this critical data.

58.	**Are there gaps in terms of information co-ordination or direction for decision-making as we transition towards an expanded and more highly renewable electricity system and meeting our emissions goals? Please provide examples of what you'd like to see in this area.**
	No comment.
59.	**Are there significant advantages in adopting a REZ model, or a central planning model (like the NSW EnergyCo), to coordinate electricity transmission investment in New Zealand?** **Would a REZ model for local electricity distribution be an effective means of addressing first mover disadvantage with connecting to electricity distribution networks?**
	More thinking and analysis could be done in relation to whether a REZ model for local electricity distribution can be an effective means of addressing first mover disadvantage with connecting to electricity distribution networks. (We have previously submitted on a REZ model for the national grid during the Transpower consultation process on renewable energy zones.[38]) We also refer to our comment above about the need to recognise and support the importance of local area energy planning (especially for EDBs and local authorities) for an optimised transition. Evidence from the United Kingdom highlights that taking a more locally led, place-based approach can deliver a net zero transition with more local support, better tailoring to local needs, and bring economic and social benefits.[39]
60.	**Should MBIE regularly publish opportunities for generation investment to enable informed market decision-making?**
	No comment.
61.	**How should the government balance the aims of sustainability, reliability and affordability as we transition to a renewable electricity system?**
	No comment.
62.	**To what extent should wholesale, transmission, distribution or retail electricity pricing be influenced by objectives beyond the (affordability-related) efficiencies achieved by cost-reflective pricing, such as sustainability, or equity?**
	We refer to our answers to questions 40 to 44. To provide some background, we note that our current approach to pricing which is set out in our *Methodology for Deriving Delivery Prices.*[40] Over the last few years we have been looking at ways our pricing (within the cost reflective pricing approach) can support decarbonisation of our economy, as well as addressing inequity, by recognising and mitigating the impact on vulnerable customers.

[38] See Transpower-REZ-Submission-2021.04.08-v1.01-FINAL.pdf (oriongroup.co.nz)
[39] See MISSION ZERO - Independent Review of Net Zero (publishing.service.gov.uk)
[40] See, Pricing Methodology at https://www.oriongroup.co.nz/our-story/pricing chapters 2 and 3.

In terms of decarbonisation, we consider that a resilient electricity supply with stable pricing will facilitate this transition and provide attractive off-peak charging options will accelerate the transition. Traditional volume-based pricing approaches can discourage electrification of transport and process heat, and act as a barrier to customers using our network to share their local renewable resources. Volume-based pricing approaches also encourages customers to make inefficient investments in technology, including expensive forms of renewable generation and devices that avoid sharing of energy resources (such as batteries and hot water diverters). Our strategy includes a transition away from volume-based pricing.

We recognise the vulnerable customers within our community, customers that do not have the resources to accommodate additional costs, nor to adapt their usage to mitigate the additional cost. We observe that more than 20% of our residential customers live in areas with a high deprivation index. Within this group, we have higher usage customers that may live in energy hardship (spending more than 10% of their income on electricity), but also a large proportion (approximately 70%) with lower-than-average usage.

Any change in pricing structure creates winners and losers. There is "collateral damage" when changes affect customers that are not contributing to an area of concern and/or are not in a position to respond. Of particular concern, we have identified that a greater proportion of our vulnerable customers sit within the lower consumption bands. While a shift away from volume-based pricing will provide lower cost outcomes in the long term, it also shifts more of the cost burden onto these customers.

We see the main tool to mitigate this impact is to implement a staged transition, spreading the change over a number of years. This provides more opportunity for vulnerable customers to adapt and for support mechanisms to adjust. We also intend to look for ways we can provide targeted relief to customers in need.

63. **Are the current objectives for the system's regulators set in law (generally focusing on economic efficiency) appropriate, or should these also include more focussed objectives of equity and/or affordability?**

We refer to the answers to the questions 40 to 44.

General Comments: