Horizon Energy Distribution Limited
trading as Horizon Networks
52 Commerce Street, Whakatane 3120
PO Box 281, Whakatane 3158
T +64 7 306 2900 F +64 7 306 2907
www.horizonnetworks.nz

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Electricity Authority
Level 7 AON Centre
1 Willis Street
Wellington, 6011

By email: **Distribution.feedback@ea.govt.nz**

Horizon Energy Distribution Limited (Horizon Networks) submission on Issues paper: Updating the Regulatory Settings for Distribution Networks

1. Thank you for providing us the opportunity to submit on *Issues Paper: Updating the Regulatory Settings for Distribution Networks.*
2. Horizon Networks is a small trust-owned Electricity Distribution Business (EDB) serving over 25,000 consumers in the Eastern Bay of Plenty region. As a trust-owned EDB, we have a strong consumer focus and seek to benefit both our shareholder Trust Horizon and the communities we serve.
3. The issues paper has been split into five discrete sections, and this submission seeks to address the themes and questions raised in each section.

Key points for Electricity Authority to be aware of

4. In addition to the points and recommendations raised in this submission, Horizon Networks wishes to emphasise the following:
    - Regulatory settings currently incentivise EDBs to use price signals to procure flexibility services.
    - MEPs have an effective monopoly position once a meter is installed, so should be regulated like a monopoly.
    - The current decentralised approach to data access creates barriers and perpetuates transaction inefficiencies.
    - Regulatory settings should recognise flexibility as an enabler and one of many options available to meet consumer's needs.
    - Part 6 of the Code is in need of review, with an emphasis on addressing the large-scale DG connection process.

General feedback

There is an increasing need for EDBs to innovate and try new approaches and new technology to accommodate rising demand

5. New Zealand intends to meet many of its climate change goals through electrification, shifting energy sources used for industry, transport, and heat away from fossil fuels and towards renewable energy sources.
6. This increased demand is expected to place an increasing strain on EDBs and the grid, as electricity is transported from dispersed generators to consumers. This will occur within networks and across the grid.
7. This creates new safety and technical challenges that will make providing a reliable supply of electricity to consumers more complex.
8. To meet these challenges, it is expected that EDBs will need to increasingly use 'flexibility services' to manage the supply of electricity to consumers.
9. These services can come from a single large-scale load or generation, or via distributed energy resources (DER) such as solar PV, EV chargers and controllable hot water load that may be spread across one or more networks.

For a flexibility market to be successful the Commerce Commission settings need to be altered to make the use of third-party flexibility services cost neutral to EDBs

10. Under the current EDB default price-quality path (DPP) settings, (regulated by the Commerce Commission) non-exempt EDBs are given a target revenue, and target allowances for OPEX and CAPEX across the network.

Providing pricing signals for flexibility services comes at no cost to the EDB

11. This target revenue is used in the price setting process and helps ensure the EDB receives a 'fair' rate of return on its assets for the service it provides.
12. In accordance with the Electricity Authority's distribution pricing principles, pricing is set to signal avoidable costs and provide an incentive for consumers with DER (such as controllable hot water) to allow it to be controlled in exchange for a reduced distribution charge (reflecting the costs that were avoided).
13. Because EDBs are recovering a target revenue, any reduction in prices for one consumer group will be re-balanced across all consumers on the network to ensure the target revenue is recovered.
14. As a result, efficient distribution pricing that has the value of the flexibility service (such as controllable hot water or EV charging response) built in is likely to be favoured by price-quality regulated EDBs. This is because the cost of providing the service is immediately reflected in the charges to the consumers benefitting from the service.

Procuring flexibility services via a contestable market comes at a cost to EDBs.

15. OPEX and CAPEX targets are set by the Commerce Commission at the start of the DPP period. These reflect the expected costs of operating the network across the DPP period.
16. Any changes to the actual OPEX or CAPEX requirements within the DPP period can result in financial incentives or penalties. For example, procuring a new paid flexibility service will result in EDBs facing increased OPEX costs.
17. As a result, the extra costs faced in suppling consumers is not reflected in prices until the next DPP reset. In the meantime, the price-quality regulated EDB faces higher costs and IRIS penalties for exceeding its OPEX allowances that it cannot recover.

While these are issues the Commerce Commission is considering, the incentives on EDBs to procure flexibility via pricing vs the open market has not been explored

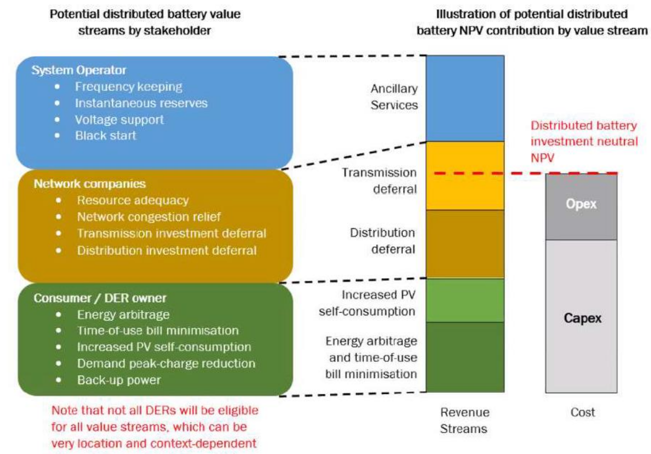
18. Horizon Networks notes that the Commerce Commission is considering these issues as part of its input methodologies (IM) review. However, the incentives EDBs have to signal consumer response (including flexibility) via pricing has not been explicitly addressed.
19. This is likely to be a barrier to the establishment of a DER market, as any DER that can support an EDB (such as EV charging or controllable DG) is likely to be incorporated into the pricing structure at no cost to the EDB rather than procured on the open market (at a cost to the EDB).
20. In order to address this the Commerce Commission should provide mechanisms similar to a 'reopener' to allow the maximum allowable revenue (MAR) to be increased so the costs of flexibility services can be passed through to the consumers that are benefiting from the flexibility service.

21. Horizon Networks Recommends: The Commerce Commission and Electricity Authority align their workstreams to ensure that changes each regulator is making supports shared goals and shared outcomes.
22. Horizon Networks Recommends: To ensure there is no bias towards pricing signals to procure flexibility services, the Commerce Commission settings should be updated to allow any OPEX resulting from procuring flexibility services to be treated as a 'reopener'' and recovered as part of the MAR. This should be done prior to a market for flexibility services being developed.

The value for certainty in response of flexibility needs to be considered

23. The consultation paper considers the 'value stack' for flexibility in a contestable market.[1]

Figure 6: Flexibility value stack



24. However, there may be instances where the long-term value of the flexibility service comes from certainty of access to the flexibility service.
25. For example, EDBs facing congestion on a section of network would want to contract for access to flexibility services that can respond every time that section of network is facing congestion. There is value to the network having certainty that this service will be available every time it is needed.
26. Horizon Networks Recommends: Any work to develop a flexibility market allows parties to continue to contract directly for priority use of flexibility services.

[1] Figure 6, page 14

Section 1: Equal access to data and information

Horizon Networks supports equal access to data and information

27. Equal access to data is desirable. It will help EDBs make efficient investment, planning and pricing decisions. It will also allow flexibility traders to have the information they need to make informed business decisions.
28. Horizon Networks supports the concept of equal access and transparency, where it is not infringing on an individual's privacy or undermining the commercial position of a company.
29. As noted by the IPAG in 2021, *MEPs have an effective monopoly position once a meter is installed*[2].
30. MEPs hold a contract with retailers for the provision of metering services and in some cases provision of metering information. These contracts have allegedly limited MEPs ability to contract with third parties, such as EDBs or flexibility traders for the provision of data and services.
31. This results in information silos that may be preventing organisations such as EDBs and flexibility traders from obtaining the information they need to support New Zealand's energy future.
32. Horizon Networks Recommends: The data structures and costs that non-trader users of meter data (such as EDBs) pay MEPs for access is regulated.

Unclear use of metering terminology throughout this section means EDB and flexibility traders needs may not be met

33. The consultation paper uses the term consumption data to refer to information collected by the MEP from the metering installation.
34. While consumption data is defined in part 12A of the Code, this definition does not consider Parts 10, 11 and 15 of the Code and the fact that MEPs only collect and provide access to raw meter data to the trader (or other party under clause 1(2) of Schedule 10.6).
35. This terminology is unclear and ideally the information made available to EDB's and flexibility traders would be sourced from validated meter readings.[3]
36. Horizon Networks Recommends: The terminology is updated to reflect how raw meter data is handled and can be traced back to the trader and MEP metering installation interrogation obligations.

EDB and flexibility trader requirements were not fully considered when metering was installed

37. Following the implementation of a refreshed version of Part 10 of the Code in 2013, there was an additional requirement for MEPs to consult with the distributor and the trader on the design of the metering installation, prior to installation or modification.[4]
38. The intention of this clause was to ensure that the EDB had a voice in the required functionality of the metering installation, however this clause has not ensured that the current metering fleet can meet future needs because:
    - Consultation was not always meaningful, and as there were no commercial arrangements between MEPs and EDBs, the EDB views may not have been acted on.
    - EDBs were not always engaged with the design of metering installations in 2013 and some EDBs had not yet considered the need for data for flexibility services and LV visibility.
    - Metering design is 'set' once consulted on, meaning MEPs can continue to use the same design as 2013 without further consultation, even when the needs of the industry change.
39. This has incentivised MEPs to use a standard design that meets the traders (retailer) minimum functionality requirements. This focus on meeting minimum retailer functionality means some metering still requires a site visit to change metering configurations.[5]
40. As a result, the current metering configuration and design has not fully considered the future needs of flexibility traders and EDBs, and there may be barriers to enhancing the design and functionality of existing metering installations to meet these needs.

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[2] Slide 21 - https://www.ea.govt.nz/assets/dms-assets/30/Access-to-input-services-final-advice-2021.pdf

[3] validated meter reading means a meter reading that has passed a reconciliation participant's validation process in accordance with clauses 16 and 17 of Schedule 15.2

[4] Clause 10.34

[5] as compared to remotely reprogramming one or more meters

41. Horizon Networks Recommends: The Code is updated to allow EDB, and flexibility trader needs to be incorporated into current and new metering installations.

42. Horizon Networks Recommends: The Electricity Authority monitors the costs associated with enhancing existing and new metering designs to ensure they are efficient and no greater than the incremental cost of providing the service.

Issues paper does not consider the efficiencies of a centralised data repository, such as the registry and MSATS[6]

43. The issues paper identifies opportunities to update the registry to implement previously proposed improvements to registry fields.[7]

44. The paper is silent on the opportunities and benefits of enhancing existing systems to improve the transparency of and access to information to help support the kinds of flexibility services New Zealand will need in the future.

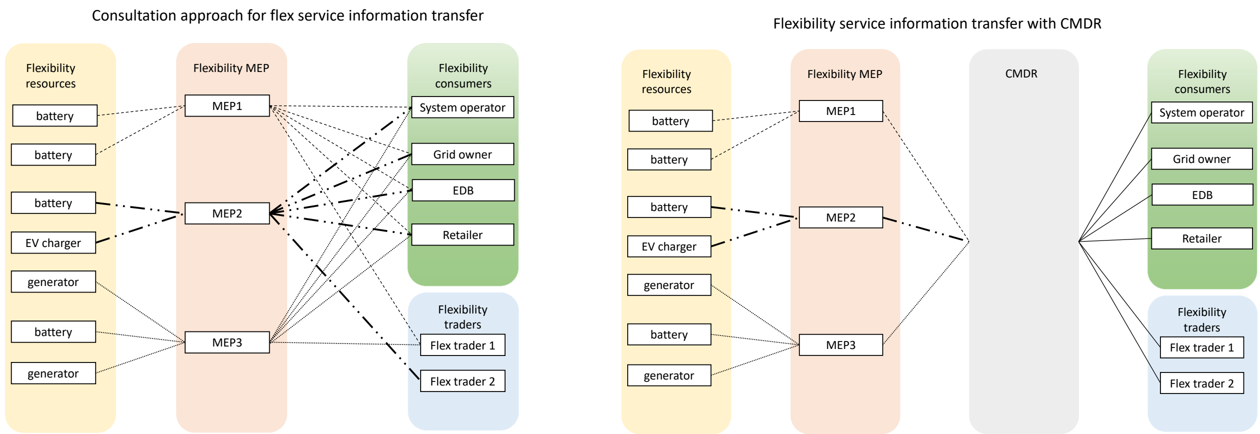
45. Improvements could include:

- **Updating the registry functionality to include DER information.** This could include the type of DER, periods of availability and DER trader (to facilitate customer switching). This would be a similar process and have similar benefits to the Part 10 update to the registry where meter information (meter categories, channels, register content codes etc) was introduced to the registry in 2013.

- **Enhancing the registry or RM systems to be a centralised meter data repository.** Having a centralised store for both DER information (registry) and metering information (consumption, generation, power quality, event logs etc) would greatly improve access to the information necessary to deliver a flexibility market[8] and reduce barriers to operating in the industry.[9]

- **Flexibility coordinator.** Having centralised coordination of flexibility services to ensure, where appropriate they are made available to the full offer stack of flexibility consumers. This could work similar to the system operator who dispatches load and generation but would be independent of flexibility consumers such as EDBs and Transpower (who could unconsciously bias decisions towards favouring their own flexibility service needs).

46. A centralised data repository (CMDR) would provide access to ICP level meter data, metering information and meta-data to organisations that provide consumer-focussed outcomes. This information would simplify transactions between participants and benefit the entire industry through allowing ICP level access to any authorised agent or person.



47. In addition to the benefits in simplifying access to data, the wider industry would benefit through, informed policy and regulation, improved network competition and planning, improved forecasting and modelling for system

6 MSATS is a centralised meter data management system, operated by AEMO for use in the Australian Electricity Market AEMO | Market Settlement and Transfer Solutions (MSATS)

7 CAR151 18276CAR-for-publishing-by-status.pdf (ea.govt.nz)

8 As there would be one 'source of truth' for information from the meter that can be used by all parties for flexibility trading.

9 For example, consumers could trade directly on the wholesale market because the MEP and RM are transacting all the information necessary for the consumer to purchase off the wholesale market.

operations, improved cost allocation and market settlement efficiency, reducing barriers to entry in the retail and flexibility markets and improving competition and transparency in the electricity market.

48. Horizon Networks Recommends: A centralised meter data repository is considered as means of ensuring timely, consistent, equal access to accurate information and supporting the Electricity Authority's wider industry CRE objectives.

Subsection 1: The case for digitalising New Zealand's electricity system

49. In this section the Electricity Authority has described how data is fundamental to enabling the development of products, and there may be a need for new standards, regulations, services, roles, and institutions.

50. The Electricity Authority is proposing to commission two studies, one to look at the UK Energy Digitalisation Taskforce consumer related recommendations, and the second to look at the problems a 'digital spine' could solve.

51. It is not clear from the issues paper what value the studies would provide and how they can support the desired outcomes from the equal access to data section.

Question	Comment
Q1. Do you see value in the Authority commissioning two separate reviews to look into the merit and practicalities of implementing the recommendations of the UK's Energy Data Taskforce around unlocking the value of customer actions and assets and setting up a "digital spine" in a New Zealand setting. The Authority will consult on the findings and recommendations of the reviews as appropriate.	No. Horizon Networks does not support the specific studies proposed the Electricity Authority. Horizon Networks considers there is merit in investigating options to unlock the value of customer actions and developing strategic assets that will support positive consumer outcomes. This is typically part of the problem definition stage of a project that could lead to consultation on policy changes. Any investigations and studies should not be limited to the UK recommendations but consider the NZ paradigm and what opportunities exist in the NZ context. Horizon Networks recommends as a priority the Electricity Authority focus its limited resources to address known issues associated with smart meter data access.

Subsection 2: What data and information do distributors and flexibility traders need, and why?

52. This section outlined what information EDBs and flexibility traders need.

53. The Electricity Authority sets out three tranches of data,

- historical ICP level volume information and power quality data
- visibility of installed DER
- real-time non-aggregated volume information and power quality data

Question	Comment
Q2. Does this capture the key data needs for distributors to make informed business decisions that will unlock the potential of DER for the long-term benefit of consumers? If not, what data is missing and what would it be used for?	No. The key information needed by EDBs is related to real-time voltage, current, active and reactive power and 'last gasp' outage information which can help support the operation of the LV network. Validated meter readings can be used post-event for DER to demonstrate that DER has responded in the way it has been contracted to or incentivised to. EDBs will increasingly need to be able to see the DER behind each ICP in order to understand what services are available and how it is responding to instructions.
Q3. Do you agree with the prioritisation of the key data needs for	No.

distributors? If not, why not and how would you suggest the priority is changed?	EDBs can access historical information from retailers to assess issues. Access to more real time information should be a priority due to its high net benefit. Real time information supports the operation of the network to meet consumer needs, manage congestion and avoid unnecessary expenditure.

Subsection 3: Flexibility traders

54. This subsection focusses on the data needs of flexibility traders.
55. The section assumes that there is a need for flexibility traders to understand customer's needs and understand the network so they can offer solutions to the EDB.
56. Horizon Networks considers it is incorrect to assume that flexibility traders will be proactively offering services to EDBs to solve congestion problems that an EDB is not already aware of and managing.
57. EDBs have a strong focus on asset management and planning, which extends out at least 10 years. All of the information available to flexibility traders will have already been analysed by EDBs and work will be underway to evaluate the most efficient solution for consumers.
58. As a result, it is more likely that EDBs will be approaching flexibility traders to seek contracts for services, rather than flexibility services lobbying EDBs to use their services.

Question	Comment
Q4. Does this capture the key data needs for flexibility traders for them to make informed business decisions that will unlock the potential of DER for the long-term benefit of consumers? If not, what is missing and what would the data be used for?	No. Horizon Networks disagrees that flexibility traders need network congestion information. This information is used by EDBs to make commercial decisions on if to contract for flexibility services to help manage current or future congestion. Giving flexibility traders this information without context may: • result in flexibility traders investing in areas where congestion is being addressed through other means • provide flexibility traders an unfair advantage in any negotiation for flexibility services where they are the sole provider
Q5. Do you agree with the prioritisation of the key data needs for flexibility traders? If not, why not?	Visibility of DER installed and available for use as a flexibility service should be a priority as it will enable flexibility traders to engage with consumers to provide services.

Subsection 4: Issue 1: Improvements to the default Data Template are required to enhance its workability

59. This section outlined the data template, which was introduced alongside the default distributor agreement (DDA) template in Part 12 of the Code.
60. The data template was intended to allow EDBs access to information on reasonable terms for certain purposes.
61. The main issue raised with the data template is that it prevents EDBs from merging information unless there is prior written agreement from the retailer. This limits EDBs ability to consider consumption in light of various demographic or third-party information that can support efficient network investment.
62. As identified in paragraphs 42-47, a centralised meter data repository will support equal access to meter data.

Question	Comment
Q6. Do you agree that the Authority should amend the Data Template to	Agree.

address the above issues to improve its workability? If not, why not?	As a priority the Electricity Authority needs ensure EDBs can access data from MEPs and retailers in a standardised format, using a standardised contract and on standardised commercial terms. Access to data should ideally made available through a centralised meter data repository. This will ensure the ultimate beneficiaries of this improved access to data (consumers) receive an equitable outcome regardless of the EDB that serves them.
Q7. Are there other changes to the Data Template that would improve it and assist it to be a useful mechanism for open access to data?	Yes. As raised in paragraph 36-41 above, the ability to set requirements for metering functionality then obtain this information at reasonable or incremental cost from the MEP or retailer. This would ensure the metering installation can meet EDBs and flexibility traders changing needs. The data template appears to be written to support ad-hoc information requests. This differs from how the issues have been portrayed, and EBDs are likely to want information on an ongoing basis.

Subsection 5: Issue 2: Retailer permissions are often necessary for distributors to receive ICP-level data for their distribution network

63. This section describes the challenges faced by EDBs to access information from metering installations, including the multiple parties involved and delays to getting information.

Question	Comment
Q8. Do you agree that this is an issue? If not, why not?	Yes. This is an issue. Horizon Networks understands that while MEPs are permitted under the Code to contract with and provide information to other persons[10], there may be contractual relationships between the MEP and the retailer that prevents this from happening. As a result, the commercial incentive of additional revenue for MEPs has historically not been sufficient to support third party access to raw meter data from MEPs.
Q9. Should the Authority amend the Code to clarify that MEPs must contract directly with distributors and flexibility traders to provide ICP data for permitted purposes? If not, why not?	Yes, although alternative interventions such as voluntary contracting under existing provisions in Part 10 of the Code may be as effective and less disruptive. Horizon Networks understands that existing contracts may be preventing this from occurring. Unless those contracts are voluntary amended to allow third party access to data from MEPs, amending the Code is the only viable option. This is because the introduction of obligations under the Code to provide information would 'override' any contractual obligations that limit access, empowering MEPs to provide this information without needing retailer consent or a contract variation to do so.

Subsection 6 Issue 3: Distributors are not permitted to receive Power Quality Data in the same way as Consumption Data

10 Clause 1(2) of Schedule 10.6

64. This section outlines issues with access to power quality data, including the fact that there is no default template in the Code for retailers to provide power quality data to EDBs.

65. The Electricity Authority proposes to amend the data template to include power quality data.

66. Horizon Networks notes this proposal has not considered electricity retailers data needs, which are focussed on the data required to support billing. Power quality is not always required for revenue purposes, so there is no value to retailers in collecting or providing this information to EDBs. The value chain is between the EDB and the MEP.

Question	Comment
Q10. Should the DDA Data Template be updated to include Power Quality Data? If not, why not?	No. Power quality data is required for managing the network but is not always held by the retailer and needs to be made available more frequently than retailers can provide it. Instead of amending only a sub-set of contracts that support access to data, the Electricity Authority should ensure EDBs can access data, (including power quality information) from MEPs and retailers in a standardised format, using a standardised contract and on standardised commercial terms. Access to data should ideally made available through a centralised meter data repository.

Subsection 6: Issue 4: In addition to gaining retailer permission to collect ICP data direct from the MEP (e.g., by completing a Data Template), a distributor must also negotiate an access agreement with the MEP

67. This section sets out feedback that a default template could be used to streamline negotiations with MEPs for data.

Question	Comment
Q11. Do you think that the transaction costs associated with negotiating the terms of access to ICP data held by MEPs is a problem that the Authority should prioritise? If no, why not? If yes, do you think there is merit in developing a default template to help reduce transaction costs?	Yes. Access to data and ability to engage with MEPs on standardised legal and commercial terms is a priority. However, a default template should not be developed until other options to address the problem are considered. An alternative to a data template, (which may not address the underlying problem of equal access) would be for MEPs to provide information to a centralised service provider (such as the registry or RM) who could manage the delivery of the same information to the various parties that need the information. The benefits of a CMDR (one way of achieving this outcome) are covered in paragraphs 42–47 of this submission. Horizon Networks staff understand that this option has been explored internally by the Electricity Authority in the past and questions why this option has not been considered in the consultation paper.

Subsection7: Issue 5: MEP pricing for provision of ICP data and other services to distributors (and other parties) is not transparent

68. This section discusses if MEPs are using their effective monopoly position to charge unreasonable prices.

69. The Electricity Authority does not consider unreasonable pricing is an issue at this stage but raises concerns that access to smart meter data is not happening quickly enough.

Question	Comment
Q12. Do you agree that MEP pricing for ICP data (including Power Quality Data) and related data services is reasonable at this stage? If not, why not?	Not able to comment on how reasonable the pricing is. Horizon Networks speculates that potential regulatory intervention is, at least in the short-term ensuring pricing is reasonable. As MEPs have an effective monopoly on the metering installation that EDBs cannot influence, there are no commercial pressures on the MEPs to provide an efficient service to anyone other than the retailer. As MEPs have an effective monopoly position once a meter is installed[11], MEPs should be limited to charging 'incremental costs' for the provision of data to third parties (under the expectation that the primary costs have already been covered by the retailer they have contracted with for metering), in the same way that EDBs are limited to charging incremental costs for generation (under the expectation that the primary costs have already been covered by the load). This will help ensure that MEPs are not incentivised to set opaque or unreasonable prices now and in the future.
Q13. Do you agree that MEP pricing for the provision of ICP data to distributors (and other parties) could be more transparent? If not, why not?	Yes. It is not clear if this is a level playing field and there are concerns that MEPs will reap excessive profits or cross-subsidise their operations to undercut their competitors for provision of services to retailers (where there is competition and the risk of being displaced).[12]
Q14. To support the transparency of pricing, standardisation, and equal access to data, do you think that the Authority should consider further implementing IPAG's Input Services recommendation that MEPs publish standard 'pay-as-you go' terms open to all parties? If yes, why, and what do you think this could cover? If not, why not?	Yes. As a priority the Electricity Authority needs ensure EDBs can access data from MEPs and retailers in a standardised format, using a standardised contract and on standardised commercial terms. Access to data should ideally made available through a centralised meter data repository. This will ensure the ultimate beneficiaries of this improved access to data (consumers) receive an equitable outcome regardless of the EDB that serves them.

Subsection 8: Issue 6: Distributors need better visibility of (non-exporting) DER

70. The Electricity Authority claims that distributors have information on the size and location of generation that is capable of exporting but do not necessarily have visibility of the locations, size and functionality of other types of DER that exist on the network.
71. It is important to have increasing visibility of DER to better forecast and predict network pressures.
72. The Electricity Authority is considering improving registry fields to incrementally improve DER visibility.
73. Horizon Networks is concerned that this approach will perpetuate the existing information flow flaws with the DG connection regime, where there is no regulatory monitoring or enforcement for generators that do not apply for a connection to the network or do not provide information within the timeframes specified by the Code. Where this occurs the EDB is currently oblivious to the existence of the generator and is unable to meet its registry population obligations.

[11] Slide 21 - https://www.ea.govt.nz/assets/dms-assets/30/Access-to-input-services-final-advice-2021.pdf

[12] For example, by offering the retailer below cost MEP service, on the expectation that they will be able to use their monopoly position as the only data provider at the ICP to set unreasonable charges for EDBs and other third-party users of the data to maximise MEP profits, to the detriment of the consumer.

74. While it would be ideal for EDBs to have complete visibility of the size and types of DER that does not export[13] but is connected behind a consumers meter to support planning, this is likely to be impractical and invasive, particularly where consumers do not want to provide DER services.
75. In these cases, the connection of an EV or new hot water cylinder (replacing gas) is considered by the consumer to be no different to connecting a toaster or heat pump.
76. Additionally, Horizon Networks notes the definition of generating unit in the Code may not cover batteries, which are considered to store and release power, rather than produce electricity. The correction of this definition to allow batteries (including EV's that can push electricity back onto the network) to be considered generators would improve visibility of DER that can have a safety and operational impact on the network.
77. Horizon Networks Recommends: Any population of registry information for all DER's that is being offered for use by consumers is made available.
78. Horizon Networks Recommends: The definition of generating unit is reviewed so that it is clear that batteries (any storage device, including EV's that can push electricity back onto the network) should be treated in the same way as generators.

Question	Comment
Q15. Do you agree that distributors' visibility of the location, size and functionality of DER should be improved within the next 3–7 years to support network planning? If not, why not?	Agree that EDBs visibility of DER should be improved to support network planning. This visibility can help EDBs understand where it is possible that flexibility services can be procured as an alternative to capital investment. The limitations of Part 6 of the Code means that DG is connected but the generator does not always follow the Part 6 requirements. Improved access to metering information will improve visibility (by providing reverse power flow indicators and 'I' flow raw meter data).
Q16. Do you have any views on the type and size of DER that need more visibility?	Yes. All flexibility services that is capable of exporting electricity onto the network and those that are to be offered for use need to be visible. This information should be populated by the flexibility traders responsible for the DER. This includes hot water (visible through LCD flag on registry), EV's, DG, batteries, flexible load (such as night store heaters) and smart appliances. DER that is not made available for flexibility services (including smart appliances and EVs that consumers chose to operate as a standard appliance) should not be required to be populated.

Subsection 8: Issue 7: Distributors do not have access to real-time consumption and Power Quality Data

79. This section raises the fact that some EDBs have commented that having real-time consumption and power quality data will become more important in the future.
80. Horizon Networks notes that current revenue metering technology used by most MEPs does not contemplate real-time provision of information, and typically communicate only a small number of times a day.
81. It is possible that non-MEP information, such as information sourced directly from smart appliances via an internet connection may be able to provide real-time information, however these are unlikely to have been through a certification regime that can demonstrate the information meets the standards of certified metering installations.

[13] To support the safety of their workers and operation of the network EDBs need to know about all devices connected to the network that are capable of exporting.

Question	Comment
Q17. The Authority acknowledges that definitions of 'real-time' vary, please explain what real-time data means to you.	The concept of 'real time' means something that is observable at the same time as it takes place. In computing and 'real time' industries such as aviation this can be measured in milli-seconds. In the electricity industry, where there is a need for processing of data and transfer of information it may be reasonable to measure this in minutes, between 1 and 5 minutes and still be considered 'real time'.
Q18. Do you agree that access to 'real-time' consumption and Power Quality Data won't be needed for at least five years?	No. There is increasing need for greater visibility of the performance of the LV network. In order to effectively operate the LV network and manage the network EDBs will need access to real-time data ahead of need. In other words, EDBs need the real-time systems setup and working well ahead of the need to use the data to help solve problems. The most important piece of real-time information EDBs need from metering installations is the 'last gasp' signal. Where available, this information helps identify where individual ICPs have lost power and gives EDBs more information so they can proactively respond to outages on the LV network. EDBs need access to data for two key functions: 1. Network Planning: This requires access to backward looking meter data on a daily basis. 2. Network Operation: This requires access to real-time data, including 'last gasp' signal in order to support the operation of the LV network and outage management.

Subsection 9 Issue 8: Flexibility traders do not have equal access to ICP data

82. This section raises concerns that flexibility traders need the same level of access as EDBs and traders who they might compete with to provide flexibility services.

83. The Electricity Authority is considering modifying the Data Template or changing the Code to clarify MEPs must provide ICP data directly to flexibility traders and EDBs.

Question	Comment
Q19. Do you agree that flexibility traders' access to ICP data must be improved so they have the same level of access as distributors (and retailers), with whom they might be competing to provide contestable services? If not, why not?	Agree that equal access is useful. Disagree there will be competition between flexibility trader and EDBs. EDBs are a consumer of flexibility services, while flexibility traders are a supplier of flexibility services. Also, it is unclear what is meant by ICP data. This may relate to: • information that is in the registry (such as metering configuration, retailer, EDB, pricing codes and loss factors) • raw meter data available from the MEP or trader • event and non-metering information such as power quality and outage flags. All this information should be available to enable the industry to function effectively as New Zealand looks towards non-network and

	non-generation alternatives to support a secure and reliable supply of electricity
Q20. Do you think the Authority should prioritise modifying the Data Template, so that flexibility traders can use it, or should the Authority prioritise amending the Code to clarify that MEPs must provide ICP data directly to flexibility traders and distributors for a set of permitted purposes without the need for retailer permission? If neither, please explain why.	Of the two options considered, updating the Code (consistent with EDB requirements) is preferred. Horizon Networks preferred alternative is for a centralised system that can be used manage access to data, so that MEPs and traders only need to provide data to one place where all interested parties can access it. This would reduce overheads and inconsistences between multiple MEPs providing data to multiple parties. The benefits of this solution are covered in paragraphs 42-47 of this submission.

Subsection 10 Issue 9: Flexibility traders do not have access to granular network congestion data on LV networks

84. This section raises concerns that flexibility traders do not have information on current congestion on LV networks and a projection of likely future congestion. This is because EDBs do not have access to the historical consumption data in order to assess congestion on the network.
85. The Electricity Authority is also concerned that once EDBs can determine congestion on the LV network, there is no requirement to share this information with flexibility traders and EDBs will use this information to provide an unfair competitive advantage to their related businesses.
86. Horizon Networks notes that the further into the LV network you get, the size and location of potential flexibility services becomes limited. As a result, constraints publication on the LV network should be limited to geographic areas where there is a viable flexibility service available.
87. Horizon Networks Recommends: To avoid inefficient decisions by flexibility trader, the Electricity Authority limit publication of constraints to instances where flexibility services may be required.

Question	Comment
Q21. Do you agree that flexibility traders need access to granular current and likely future congestion data on distribution networks within the next 1–3 years?	No. Flexibility traders will provide a service that enables EDBs to manage congestion on their network. Where congestion is identified EDBs will need to look at what are the most effective options for managing that congestion. This could include contracting for flex services. Publishing constraints does not change the EDBs decision and may result in flexibility traders investing in technology in areas to alleviate constraints that EDBs are unwilling to pay for because better alternatives are being developed. Additionally, it is unlikely that the LV network will be where flexibility it initially required. Sections of the LV network serve less consumers, so the overall value of alleviating constraints is lower. It is more likely that flexibility will initially be required to address constraints and defer investment in the HV network. Because the HV network involves more costly investment, deferral of investment has a higher value to EDBs that can make providing a flexibility service more attractive to flexibility traders.
Q22. Are there any other issues preventing distributors from providing	Not on the HV network. This information is already provided in our asset management plans.

granular current and likely future congestion data?	Improved visibility of the LV network is essential before action can be taken to provide appropriate information on where there is congestion or voltage issues that a flexibility service could help alleviate.

Subsection 11 Issue 10: Flexibility traders do not have visibility of the location, size, and functionality of DER on LV networks

88. The Electricity Authority considers there are shortcomings in the registry fields, including the fuel type, non-generation DER and batteries.

89. The Electricity Authority proposes to update the fields in the registry to include DER.

90. Horizon Networks considers that it is appropriate to update the registry for DER, but this should follow a similar process as the introduction of metering information, where process flows, and ownership of the information is clear and traceable. Horizon Networks does not support any proposal that would place additional obligations on EDBs to populate registry fields with information that EDBs are not responsible for.

Question	Comment
Q23. Do you agree that visibility of the location, size and functionality of larger DER needs to be improved within the next 3–7 years to help understand the drivers of network congestion, what DER is 'controllable', and what services could be offered to owners of DER? If not, why not?	Yes. The visibility as to the location and size, and of all offered DER needs to be prioritised within the next 3-7 years. This will help EDBs and consumers of flexibility services know where these services may be available, so the can be procured where needed. Horizon Networks expects this functionality could work in a very similar way to retailer and MEP switching on the registry, where available DER information is populated by the flexibility provider and is visible to those that need the DER service.
Q24. Do you have any views on the type and size of DER that flexibility needs to have improved visibility?	Flexibility traders and EDBs will need to know what DER is in each area to understand what potential response is available to avoid network investment. This is limited to what flexibility is available to use. Information about devices that are flexibility capable, but the customer is not willing to offer (such as a consumer's smart appliance) are not necessary and requiring consumers to provide this information would be problematic and difficult to enforce. Horizon Networks recommends DER information is made available through an 'opt-in' process where consumers who have DER capable devices (such as EV chargers, smart appliances, and DG) can engage with an industry participant (such as flex trader or EDB or retailer) to have the information populated, identifying that this equipment is available to provide flexibility services.
Q25. Do you think that the Authority, instead of a DER registry, should consider amending the registry data fields and /or requirements to improve DER visibility?	The Electricity Authority should have a fully functional centralised meter data system, that includes both the meta-data (type of DER, available periods etc) as well as the raw meter data and power quality information (as appropriate). The benefits of this solution are covered in paragraphs 42-47 of this submission. It is logical to incorporate the DER meta-data information into the registry as the primary identifier for DER is likely to be the ICP identifier. The ICP identifier is already used in the registry to associate

	information about the point of connection (retailer, EDB and MEP information). If a stand-alone solution is developed it should be done in a way that integrates with the ICP level information already contained within the registry. Any DER registry system should also include flexibility trader switching functionality, similar to the registry trader, EDB and MEP switching process.
Q26. Do you agree that the Authority should prioritise work on addressing the other issues outlined in this chapter?	No. In order for DER and flexibility services to be traded, there is a need for a platform to be developed that allows the parties offering and consuming flexibility services to see where these services are and what these services can provide. A centralised database for DER information and DER raw meter data and associated metering information is necessary to support a transparent, accessible, and competitive flexibility market, in the same way that the electricity registry and reconciliation manager are necessary to support and open and competitive retail market. The necessary order of progress is: 1. **Access to LV information** – this will improve EDBs understanding of where congestion is occurring within their network. 2. **Creating a flexibility trader industry participant** – this will enable the Electricity Authority to support and regulate parties providing flexibility services and information. 3. **A centralised flexibility database** – this will support flexibility traders identifying the flexibility services and ICPs they trade at that are available for use and will and support flexibility trader switching. 4. **Access to flexibility metering information** – this will enable flexibility trader to provide flexibility services and demonstrate those services are meeting the contracted flexibility consumer's needs. Ideally this will be through a centralised metering database as covered in in paragraphs 42-47 of this submission. With these pieces of information, there will be greater access EDBs can start contracting for flexibility services as an alternative to capital investment, in a transparent and competitive environment that empowers consumers to choose who they offer their services to.

Subsection 12 Issue 11: Flexibility traders do not have access to 'real-time' granular congestion or ICP data

91. The Electricity Authority considers that the barrier to access to real-time congestion and ICP data is that MEPs are only just beginning to offer this data service.

Question	Comment
Q27. Do you agree that flexibility trader access to real-time congestion and ICP data won't be needed for at least five years?	Horizon Networks agrees that flexibility traders are unlikely to need real-time information for at least 5-7 years. There may be a need to respond to signals or parameters set by the flexibility consumer (such as the EDB). This may be similar to the

	current AS/NZS ISO 4777 requirements for inverters that enable settings that respond to the frequency on the network. The ICP data currently available on the registry is an historical record that is populated several days after the change has occurred onsite. Horizon Networks would not support any shift to requiring real-time population of ICP data on the registry without a clear problem to address and technology to enable it to comply.

Subsection 13 Issue 12: Privacy Law transparency requirements could be perceived as a barrier to disclosing ICP Data

92. The Electricity Authority considers that privacy laws can be seen as a barrier to providing data about a given ICP, including information contained in the registry and information collected from the metering installation.
93. The Electricity Authority is proposing to provide model privacy terms and may consider working with the industry to improve privacy management techniques.
94. Horizon Networks agrees that businesses are incentivised to minimise their exposure to privacy breaches, and in doing so will work to limit third party access to information in ways that may be seen as creating barriers to competition and innovation.
95. Horizon Networks considers there are many examples where information similar to metering information and registry information is available and not considered personal, such as housing records (sales, council records, easements). This is similar to electricity information, where the information is associated with the property rather than a specific individual within the property.

Question	Comment
Q28. Do you agree that model privacy disclosure terms are appropriate? If not, why not?	Yes. Customers need to know where their data is going and how it is handled, so from that point of view model terms will be helpful. By codifying a requirement for MEPs to provide raw meter data this transfer of information bypasses the retailer. As a result, the retailer loses control over how that data is being handled or managed (in the same way they don't have control over the ICP information in the registry and how that data is handled or managed). Given the customers contract will be with the retailer and/or flexibility trader there needs to be model terms to support efficient access to information.
Q29. Do you agree that model privacy disclosure terms would facilitate data access? If not, why not?	Yes. However as noted in paragraphs 42-47 of this submission the benefits of improved data access can best be facilitated through a centralised system rather than requiring a 'spiderweb' if information flows between each MEP, retailer, EDB and flexibility trader, each covered by their own bespoke agreements, systems, and processes.
Q30. Do you see any practical issues with this proposal?	Yes A practical issue is the relationship the customer has with the retailer, that does not exist with the MEP. If retailers have different privacy terms, but the MEP is providing data directly to EDB / flexibility traders on different terms there may be a mismatch between the privacy the customer expects under its contract with the retailer, and the level of privacy they are actually getting due to regulated information flows.
Q31. Should the Authority create model terms for distributors and MEPs as well given the range of data	Yes.

being collected through smart meters? If not, why not?	Horizon Networks supports a consistent process for handling data that may be considered private and guidance from the Electricity Authority would facilitate this. As MEPs and EDBs do not have a contract with the customer, it is unclear how these model terms could be applied without regulation.
Q32. Would the industry find it helpful for the Authority to conduct workshops on privacy preserving/ minimisation techniques?	Yes. The risk and impact of privacy breaches is forefront for many industry participants and may be responsible for unnecessary barriers to information sharing. Workshops and published standardised approaches to the sharing of information can help overcome these barriers.

Section 2: Market settings for equal access

Horizon Networks supports market settings that allow non-network solutions (NNS) to be assessed alongside capital investment

96. As a small trust-owned Electricity Distribution Business (EDB) serving over 25,000 consumers in the Eastern Bay of Plenty region, Horizon Networks has a strong consumer focus and seeks to benefit both our Shareholder Trust Horizon and the communities we serve. Where it can be demonstrated that the community and our shareholder will be benefit from NNS, Horizon Networks wants to be able to implement NNS.
97. Like several EDBs, Horizon Networks has a self-supplied NNS option available to help manage peak load, through ripple control and hot water.[14] This is an example of investing in an early form of flexibility service to reduce the overall cost of distribution services to consumers.
98. However, EDBs, including Horizon Networks face unnecessary barriers to utilising flexibility services in the future through:
    - A lack of visibility of available flexibility services to support 10-year planning.
    - A lack of access to ICP level information to help identify congestion on the LV network.
    - Certainty that flexibility services will respond when needed.
    - Commerce Commission default price path (DPP) settings that incentivise discounting distribution charges over making payments for flexibility services.
99. As noted in section 1, a centralised registry of flexibility services and centralised database containing raw meter data and associated information collected by the MEP will allow EDBs to identify where it is possible to procure flexibility services. This will allow EDBs to know who to approach when seeking to consider NNS in its 10-year AMP.
100. However there remain concerns around the ability of flexibility services to respond when needed and for the DPP settings to support flexibility services.

There is value in guaranteed response for flexibility services

101. As noted in paragraphs 23-26, the Electricity Authority has identified a value stack that considers how flexibility can provide services across the market.
102. For many EDBs, flexibility services are required to address a specific issue that would traditionally be addressed by capital investment.
103. To defer capital investment, EDBs need to have certainty that when the issue is being experienced, the DER will respond. If DER does not respond, this creates issues with the supply of electricity to consumers and accelerates the need for investment to address network issues.
104. DER that is optional (for example EVs with the ability to 'over-ride' the DER signal) or that is not always available for the is unlikely to meet the EDB, and consumers needs.
105. These issues can be solved by allowing EDBs to contract for flexibility services in a way that ensures a priority response from the service for the EDB where there is value having this priority response.

Commerce Commission settings currently incentivise EDBs to offer discounts for flexibility services

106. As noted in paragraphs 10-22, the Commerce Commission DPP settings currently incentivise EDBs to offer pricing discounts for flexibility over making payments.
107. This setting is a barrier to flexibility trading and until the Commerce Commission allows EDBs to 'reopen' their MAR for flexibility services this will result in EDBs continuing to apply cost reflective prices that incorporate the value of flexibility services into those prices.[15]

[14] Due to the current network usage and projected growth, Horizon Networks does not currently utilise ripple control to manage peaks, so no tariff is offered to reflect the value of the deferral of investment.

[15] For example, a controllable load tariff considers the cost reduction the consumer is providing the EDB through providing a hot water flexibility service.

Subsection 1 Issue 1: Distributors may prefer network solutions when non-network solutions could be more efficient

108. This section raises concerns that opportunities may be missed to decrease costs to consumers and meet climate change targets. The Electricity Authority considers these opportunities are being missed because the level of uptake of NNS varies by EDB.

109. The Electricity Authority is considering:

- Providing education and guidance on flexibility services; or
- Funding trials and / or assistance with contracting for NNS; or
- Requiring EDBs to show they have explored NNS.

110. Horizon Networks considers the most immediate barriers to the update of NNS are visibility of the LV network and knowledge of what viable NNS solutions are available.

Question	Comment
Q31*. What are your views on the three options presented above, to deal with Issue 1 (that distributors might prefer network investments to NNS)? What alternative option/s would you favour, if any?	Horizon Networks undertakes a thorough analysis of the comparative benefits of making a CAPEX (network) or OPEX (non-network) investment to provide a reliable supply to consumers on our network. Typically, these are for major investments that will justify the additional time and effort required to assess the various options and support a non-network alternative over a long (45 year) period of time. Of the options provided by the Electricity Authority, Horizon Networks supports option 3 - requiring EDBs to show they have explored NNS. This option 3 sits clearly within the Commerce Commission remit to measure the performance and efficiency of EDBs. This can be achieved through existing work being undertaken by the Commerce Commission to review the information disclosure requirements.

Subsection 2 Issue 2: Distributors may favour in-house NNS

111. This section raises concerns that where NNS can be demonstrated to provide a net benefit, EDBs may seek to self-supply NNS even when it is more efficient to procure it from a competitive market.

112. The Electricity Authority is considering:

- Providing education and guidance on procurement of NNS; or
- Enabling multiple trading relationships (MTR); or
- Encourage EDBs to make standing offers for DER; or
- Monitor EDBs use of competitive procurement; or
- Impose arms-length rules for flexibility services.

113. Horizon Networks considers it is likely premature to assume that in-house NNS are favoured. Current Commerce Commission DPP settings and Electricity Authority cost-reflective pricing settings encourage EDBs to incorporate the value of flexibility services into their prices over going to market for a flexibility service.

Question	Comment
Q32*. Do you agree with the tentatively preferred intervention to deal with Issue 2 (Option 3: encourage standing offers) and the collection and monitoring of information proposed under Option 4? If not, what alternative option/s would you favour, if any?	Horizon Networks supports a 'least regrets' approach to procuring flexibility services, through Option 1 (Education) prior to any decision on intervention. The issues raised here are not unique to flexibility services and the arguments around competition could equally be extended to other services such as lines maintenance contracts, SCADA or control room services and IT services.

	In each of these cases the EDB has the choice to seek a competitive tender (which may be from a very limited pool of providers), or self-supply balanced against regional location, guaranteed access to resources, and ensuring sustainable development of local workforce. The Commission and Authority have seen first-hand the impacts of storms such as cyclone Gabrielle which wreak on communities and the benefit of EBDs having a skilled workforce capable of rapidly pivoting to respond to emergencies. Commercial decisions are made based on an assessment of the long-term benefit, which generally means the lowest cost and highest value service is chosen. Flexibility services are no different and should be procured in a way that is consistent with other EDB procurement decisions where the EDB has the discretion to determine the preferred solution and negotiate with potential providers. It is also worth noting that some flexibility services such as hot water cannot be tendered for.
Q33. Do you think there are circumstances in which the Authority should extend the Arm's-Length Rules? If not, why not?	No. The Commerce Commission already regulates EDBs and the related parties at arm's length rules. Flexibility services are no different to other services an EDB may choose to self-supply for commercial reasons. Creating specific arms-length rules for DER would set a precedent that other contestable services such as line maintenance, control room services and SCADA could be subject to arms-length rules that would limit an EDBs ability to self-supply.

Subsection 3 Issue 3: Distributors could use their monopoly position in distribution to secure an advantage in contestable markets

114. This section raises concerns that EDBs could use their market power in regulated services to gain advantage in one or more potentially contestable markets (including but not limited to NNS). The Electricity Authority believes it is possible for EDBs to use information only it has access to, to gain an unfair advantage in unregulated services the EDB may provide.

115. The Electricity Authority notes this is not limited to NNS and was raised with the Commerce Commission in 2017.

116. The Electricity Authority is considering:

- Monitoring behaviour of EBDs in contestable markets
- Imposing arm's-length rules on EDBs

Question	Comment
Q34. Do you agree with the Authority that Option 1 should be implemented, and that Option 2 should only be considered in the event of allegations of, or instances of anti-competitive harm in contestable markets (Issue 3)? If not, what alternative option/s would you favour, if any?	The Commerce Commission is the primary regulatory responsible for addressing anti-competitive behaviour. Anti-competitive behaviour is not limited to EDBs, and any organization can cross-subsidise its operation to gain an unfair advantage in a market. There are examples where a dominant player, uses its position to extract a competitive advantage. Horizon Networks recommends that any monitoring is not limited to EDBs but to all participants within the contestable markets that may

	seek to use its resources unfairly and there is the opportunity for consumer harm.[16] This is best undertaken by the Commerce Commission as it is related to competition effects.[17]

[16] For example, electricity retailers limiting flexibility traders' access to data to gain a competitive advantage for the retailers own flexibility trading service.

[17] The Commerce Commission has published case studies on the misuse of market power, including by monopolies and dominant players. https://comcom.govt.nz/business/avoiding-anti-competitive-behaviour/taking-advantage-of-market-power

Section 3: Capability and Capacity

117. The pivotal role of electricity in decarbonising the economy will be hampered by any issues in sourcing adequacy resources (people and equipment) to transform networks.

118. The Electricity Authority wants to ensure that the sector has sufficient capacity to enable the projected significant uptake of DER an facilitate a low-emissions economy.

Subsection 1 Issue: Distributors have insufficient capability and capacity

119. The Electricity Authority is concerned that there may be insufficient capability and capacity within EDBs to meet future DER needs and intervention may be necessary.

120. The Electricity Authority is considering:

- Encouraging collaboration, combined with training and education.
- Encouraging joint venture arrangements / regional clustering.

Question	Comment
Q35. What do you think of the Authority's option of using the education option proposed elsewhere in this paper, to include some guidance on how distributors should collaborate in future?	The education options raised earlier in the paper will not address the problems identified. EDBs are well integrated and supported by the ENA. EDBs already have the tools to collaborate on initiatives that can benefit all EDBs in NZ. A key issue raised in the paper is the concern that this collaboration is leading to an increase in monopolistic behaviour. Horizon Networks strongly disagrees and considers the opposite is true. As the consumer of flexibility services, EDBs need competition and low-cost alternatives to CAPEX to help support NZ's energy transition. This requires EDBs to be able to have the skills to evaluate NNS. Collaboration between EDBs could be extended to include flexibility providers (where flexibility is the focus of the conversation) to improve transparency and accessibility to the flexibility services EDBs will need in the future.
Q36. Do you think it would be helpful for the Authority to encourage the use of joint ventures between distributors to increase their integration of DER and their procurement of NNS projects? And should this be combined with the first option?	No. This is a commercial decision and option that already exists.

Section 4: Operating agreements for flexibility services

121. While there are not large issues with flexibility services operating arrangements that would require intervention, the Electricity Authority wishes to support industry-led work on operating arrangements.

122. The Electricity Authority intends to monitor progress between Transpower and EDBs on the process to agree a standard offer form for procuring flexibility as an NNS and how this aligns with overseas developments.

Question	Comment
Q37. Do you agree with the proposed approach to monitor progress between Transpower and distributors in developing standard offer forms for procuring NNS, and monitor whether issues associated with operating agreements for flexibility services are developing, and prioritise resource to progressing the other chapters? If not, why not?	Yes. Contracting for NNS requires a market to be established and functioning. The Electricity Authority should remain open to the concept of NNS beyond what is described in this chapter (a payment to a provider). NNS operating agreements may be as simple as a pricing plan for retailers that are able to provide a flexibility service (reflecting the reduced costs to supply those consumers).
Q38. Do you have any views on the best way the Authority can monitor whether issues associated with operating agreements for flexibility services are developing?	Ongoing conversations with suppliers and consumers of flexibility services is the most effective way to subjectively monitor the agreements.
Q39. Do you have any suggestions for how the Authority can support industry-led work on providing guidance on best practice and templates for operating agreements?	Ongoing conversations with suppliers and consumers of flexibility services

Section 5: DER Standards

Horizon Networks supports reviewing Part 6 of the Code

123. This section considers DER standards that may be needed to support adoption of DER. DER includes distributed generation (DG) that is regulated by Part 6 of the Code.
124. The Electricity Authority is considering reviewing Part 6 of the Code and extending Part 6 of the Code to include DER.
125. Horizon Networks supports a review of Part 6 of the Code. There are multiple operational and policy issues that are limiting EDBs ability to manage their network and support the safe, efficient uptake of DG.
126. The Electricity Governance (Connection of Distributed Generation) Regulations 2007 (which became Part 6 of the Code in 2010) have not been substantively reviewed since 2007.[18]
127. Horizon Networks consider that there are issues with Part 6 that would be timely to resolve. These include:
    - Part 2 Connection process
    - Prescribed fees
    - Monitoring and enforcement of connecting DG obligations under Part 1 and Part 1A
    - Clarifying the definition of generating plant and generating equipment to recognise the impact of batteries

The Part 2 Connection Process needs to be reviewed as a priority

128. The Part 2 connection process (generators greater than 10kW) is a bespoke application process that is needing to cover increasingly complex connections.
129. The Part 2 connection process was developed in 2007, prior to global reconciliation and the provision of metering and DG information on the registry. At this time unless the generator was selling to the incumbent retailer, the generator would need to have an NSP identifier (similar to how GXPs and embedded networks have an NSP identifier) that was managed in the reconciliation system.
130. Given the complexity in becoming a generator in 2007, expectation at the time was that there would be very few of these applications and EDBs would be resourced to manage the applications.
131. However, in 2023, with the recent shift in focus to electrifying the economy, the number of applications under Part 2 is increasing, and the complexity of the connections is also increasing. As a result, the processes and timeframes that were designed for 2007 are no longer fit-for-purpose.
132. In particular, the timeframes assess if an application is complete and to provide information to the DG are unreasonable where the connection is complex, and it is necessary to undertake material engineering review to understand how the EDB can support the connection of the DG.
133. For less complex connections, that were more common when the process was developed the 30-business day timeframe is reasonable.
134. Horizon Networks Recommends: The Code is amended to allow the EDB to provide a reasonable estimate of a timeframe for when it can provide the information under clause 12, within 10 business days (BDs) of receiving the application (as part of the initial assessment process). The timeframe can then be discussed and agreed with the DG.

The prescribed fees are resulting in a cross-subsidy from consumers to generators

135. As noted above the prescribed fees have not been reviewed since implementation in 2007 (apart from a clarification regarding GST and arbitrary 1A fees in 2015).
136. As a result, for many connections, particularly substantively complex applications made under the Part 2 process the prescribed fees for connecting the DG are materially lower that the cost to the EDB in processing the application.
137. This means that the costs for connection need to be considered expenses incurred in the operation of the network, which are ultimately borne by consumers. This is a cross-subsidy from consumers to DG.

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[18] There was an operational review that established a new Part 1A connection process and clarified the treatment of GST in 2015 and minor update to include hosting capacity in 2021, however the established processes and fees remain essentially unchanged from 2007.

138. Cross-subsidies are undesirable as they encourage DGs to connect when it may not be economically efficient to do so if they were to face the true cost of connection.

Regulated fees for EDBs to processing large-scale generator applications, which are not aligned with Transpower's connection fees may lead to inefficient investment decisions

139. EDBs fees for processing applications from large-scale generators (1MW or greater) are currently capped at $5,000.

140. Transpower's fees for processing large-scale generators are:[19]

The structure of the Application Fee is set out below:

Minimum	$50,000
Connection capacity up to 100 MW	$2,000 per MW
From 101 to 200 MW	$1,000 per additional MW
From 201 to 300 MW	$500 per additional MW
From 301 to 500 MW[3]	$250 per additional MW
Maximum	$400,000

MW is defined as the requested maximum generation injection capacity in MW of the generation provided in section 2.2 of the Application Form.

141. As a result, generators face a materially lower application fee to connect to a local network, even though the work required to process the application will be almost identical to what is required to connect to the grid. This lower up-front fee (which occurs at a point where the prospective generator may still be seeking capital) can influence generators to connect to a local network, even when it may be more efficient to connect to the grid.

142. Aligning EBDs fees for large scale generation with the Transpower generator connection process will remove an imbalance in cost allocation that can lead to inefficient decisions.

143. Horizon Networks Recommends: The Code is amended to allow the EDB to align the application fees for large scale generation with Transpower's large scale generation application fees. This will ensure that the costs of processing the application are recovered and there are no incentives to inefficiency connect to the grid or local network.

Monitoring and enforcement of connecting DG obligations under Part 1 and Part 1A

144. The Part 1A process is having the desired effect of providing a streamlined way for small generators with approved inverters to connect to the network.

145. However, the Electricity Authority is placing obligations on these generators to provide the EDB records of connection, including the Code of Compliance and Record of Inspection that show the DG has been connected, and in a safe manner, but compliance with these obligations is not being monitored or enforced.

146. This information is essential to manage the safety of the network. The lack of DG compliance with this clause increases the cost of connecting small scale DGs and creates safety and compliance risks for EBDs that are outside of their control.

147. Horizon Networks recognises that it is undesirable to take enforcement action against individuals with small scale DG, but there needs to be an incentive to support DG compliance with the Part 6 of the Code.

148. An alternative to compliance action would be to develop an explicit disconnection process that would enable EDBs to take action against DGs that have not followed the Part 6 connection process until they comply.

149. Horizon Networks Recommends: The Code is amended to include a prescriptive method for EDBs to notify unauthorised or non-compliant DG of their obligations, seek remediation by the DG and only if all reasonable options are exhausted, disconnect the DG until it can comply with the Code.

The definition of generating plant and generating station may not include batteries

150. The definition of generating plant and generating station in Part 1 of the Code refers to equipment that produces electricity.

[19] https://www.transpower.co.nz/connect-grid/our-connection-process

151. It is not clear if the Electricity Authority considers that batteries produce electricity (via a chemical reaction) or simply store and release electricity.

152. This ambiguity makes it difficult to know how to treat batteries within Part 6 of the Code.

153. From an EDB point of view, batteries that are discharging have the same impact as any other generator and should be considered generators under the Code.[20]

154. Horizon Networks Recommends: The Electricity Authority clarify that batteries are considered generators.

Subsection 1 Proposed scope for the Part 6 review

155. This section describes how Part 6 of the Code was written when solar applications were fewer and residential in scale.

156. The Electricity Authority is proposing to make changes to the Code, including making Part 6 of the Code explicitly refer to all forms of DER and amending the DG application process.

157. Horizon Networks notes that amending the Code to explicitly include all forms of DER will undermine the current purpose of Part 6 of the Code[21]. The connection of DER that is simply controllable load such as a smart appliance should be no more onerous than the connection of a standard appliance.

158. It is only when the smart appliance is being offered as DER that EDBs and flexibility traders should want to know about it, and this is better suited as a registration, rather than connection process.

Question	Comment
Q40. What are your thoughts on the proposed scope for the Part 6 review? What, if anything, would you include or exclude, and why?	Agree that a review of Part 6 is timely and necessary. Disagree on the need to amend Part 6 to explicitly include all forms of DER. This in unnecessary and non-generating DER that are being offered into the market should be covered by a registration rather than connection process. Disagree on 2c) no change to Part 1 (comprehensive) or Part 2 approval timeframes. The approval time frames should be reviewed as a priority. The electrical system is becoming increasingly complex, and sufficient time should be allowed to complete the required analysis, given the ever-increasing number of applications. As noted above Horizon Networks would also like to see a prescriptive method to notify and disconnect unauthorised distributed generators. The current clause in the Code and any impact of non-compliance does not reflect the associated health and safety risk. In addition to the connection process, the review of Part 6 should look at mechanisms to improve communication between EDBs and retailers, and to develop mechanism that reduce the likelihood of unconsented DG connecting and causing safety and operational issues on the network.
Q41. In order, what are the three most important issues that should be addressed as part of a Part 6 review, and why?	The most important issues that should be addressed as part of a Part 6 review: **Amend Part 6 DG application processes** – the process has not been well suited for Part 2 applications and the volume of Part 1 applications has significantly increased since the last major review of Part 6 of the Code.

[20] Including batteries from EV's that can provide a reverse power flow onto the network.

[21] The purpose of this Part is to enable distributed generation to be connected to a distribution network or to a consumer installation that is connected to a distribution network, if being connected is consistent with connection and operation standards.

	Review Part 6 prescribed maximum fees – the complexity of applications, particularly Part 2, mean the EDBs internal costs significantly exceed the maximum fees, resulting in an inefficient cross subsidy between consumers and connecting DG. This review should also provide clarity around the ability to recover costs for activities not explicitly covered by Schedule 6.5. **Strengthen Power Quality Standards** – AS/NZS 4777 should be mandated for all Part 1 applications, we expect this should be relatively straightforward.[22]

Subsection 2 Amend Part 6 to explicitly include DER

159. The Electricity Authority considers there are a range of issues to consider including how DER applications may respond to system operator requirements and if battery storage systems are DG.

160. Horizon Networks believes that battery storage systems should be considered DG but that other forms of DER that do not result in electricity being pushed onto the network are no different to non-controllable load and should not require a specific connection process.

Question	Comment
Q42. What are your thoughts on amending Part 6 to explicitly include DER, and what do you think are the key issues to be considered?	Horizon Networks does not support increasing the scope of Part 6 to include the connection of DER that does not put electricity onto the network. DER that is load-based (such as. EV charging, smart appliances, hot water) should not need a connection process, but instead should have a separate registration process that allows DER that meets specific standards to be offered into the market. When considering if to amend Part 6 to explicitly include DER the Electricity Authority should consider what problem this amendment is addressing and what incentives or barriers this process it may place on consumers who are considering installing DER capable appliances and EV chargers.

Subsection 3 Amend Part 6 DG application processes

161. The Electricity Authority is considering if changes to better respond to an increasing number of DG applications of increasing size and complexity is appropriate.

Question	Comment
Q43. What are your thoughts on increasing the size threshold for Part 1 DG applications, including the benefits and drawbacks?	Horizon Networks recommends keeping the sizing of the Part 1 and Part 1A process sizing as is. A 10kW or lower DG installation is likely to be able to generally self-supply most residential and small business consumers with some small export onto the grid. Individual connections of this size are unlikely to be very disruptive to the network and will not require site-specific analysis. Once DG connections exceed 10kW, the DG is likely to be exporting more often and the size of the connection required increases (similar to how if a consumer has more load onsite, they may need a larger connection to the network). This means consumers may need a fusing

[22] Over the past 12 months, Horizon Networks has not received any Part 1 applications (all have been Part 1A), so extending AS/NZS 4777 should have no impact on consumers DG connection decisions.

	and tariff change to reflect the increase in capacity and service required to support the consumer. By having a more customised process for the connections exceeding 10kW, we can have these conversations with the generators to discuss the physical changes that may be required to support the connection in a timely manner. This that ensures the generator is making a decision that allows it to make effective use of the generation they wish to install while meeting network operating standards.
Q44. If the threshold were to change, what do you think the new threshold should be and why?	Part 1A should remain at 10kW and below. If the threshold for Part 1 was to be increased, a threshold of 15kW may be suitable as connections greater than this are likely to require a capacity upgrade. A 15kW threshold would need to require inverters meet the latest AS/NZS4777 standards (note: it is possible that these installations will not be able to effectively generate all available electricity to the network depending on the size of the connection to the network and impact the generation is having on voltage and frequency).

Subsection 4 Adjust the Part 1A (streamlined) processing time

162. The Electricity Authority considers it is important that the Part 1A process encourages rapid update of DG and supports consumers in getting the greatest benefit from their DG.

163. The Electricity Authority is interested in knowing if the current approval timeframe for Part 1A is appropriate.

Question	Comment
Q45. What are your thoughts on adjusting the ten-business day timeframe in Part 1A?	10 business days is sufficient for EDBs to ensure the DG meets the requirements for connection. Horizon Networks notes that 10 business days is a deadline, not a target and EDBs endeavour to provide approval as soon as practicable. The review of DG applications is a technical process that requires staff with electrical engineering experience. These staff are shared across the business so do not solely look at DG applications. Reducing the timeframes would require EDBs to hire more staff to comply and so that staff are always available to review these applications as they come in. This will increase the costs associated with processing DG applications. Horizon Networks would only support a decrease in timeframes if there were an ability to recover these additional costs from the applicants.

Subsection 5 No change to Part 1 (comprehensive) and Part 2 approval timeframes

164. The Electricity Authority is considering retaining the approval timeframes for the Part 1 and Part 2 DG application processes.

165. Horizon Networks considers a review of the Part 2 approval timeframes is the most important issue to be considered by the Electricity Authority.

166. In particular the Part 2 application process is designed to cover complex applications that require significant engineering time and expertise to analyse.

167. The timeframe to assess if a complex application is complete is too low and should be increased to 10 business days. The application review process can involve reviewing many complex technical documents and assessing

these against the connection and operation standards. It is not always possible for our engineering resource to review these and make an assessment as to the completeness of the application within 5 business days.

168. Similarly, the 30-business day timeframe to provide information to the DG[23] is too onerous. For complex connections it can take many months of engineering work to understand how the DG intends to connect to the network and how this form of connection will impact the operation of the network and the operation of the grid.

169. As noted in paragraph 133, Horizon Networks recommends that the Code is amended to allow it to provide a reasonable estimate of the time requires to assess and provide information back to the DG.

Question	Comment
Q46. What are your thoughts on maintaining the current approval timeframes in Part 1 (comprehensive) and Part 2?	Horizon Networks considers Part 1 approval timeframes are appropriate. Horizon Networks considers the Part 2 approval timeframes need to change as a priority as they do not take into account the complexity of some connections. The 5-business day timeframe for advising if the application is complete is too short, it should be at least 10 business days. In many cases the application is unique, complex, and requires comprehensive review of many technical documents to understand if the application is complete and addresses the requirements set out in the Code. This review takes many days, and it is not always possible for our engineering staff to start the review on the day the application arrives. For complex connections, the 30-business day timeframe to provide information to the DG under Clause 12 of Schedule 6.1 is unrealistic. These requirements can take many months of engineering work to understand how the proposal (which may not contain sufficient information to understand how the DG will connect to the network), what measures will be required and how to assess the costs of those measures. These requirements will vary extensively on a case-by-case basis, particularly for large scale DG. It would be more reasonable to allow the EDB to provide a reasonable estimate of a timeframe for when it can provide the information under clause 12, with 10 business days of receiving the application (as part of the initial assessment process). The timeframe can then be discussed and agreed with the DG. For less-complex DG applications under Part 2, the 30-business day timeframe is reasonable.
Q47. If you seek a change to approval timeframes, what evidence can you give to support this?	For Part 2 applications that have an impact on Transpower, Horizon Networks will request a Concept Assessment report from Transpower. These reports currently have a lead time of 45 Business days[24], which means that Horizon Networks does not know the full scope of changes required to facilitate the connection of the DG for at least, and generally more than 45 business days.

[23] Clause 12 of Schedule 6.1

[24] https://www.transpower.co.nz/connect-grid/our-connection-process

Subsection 6 Add a new application process for large-scale DG to Part 6

170. The Electricity Authority is considering adding a new application process for large-scale DG to Part 6 of the Code. This is because large scale DG is inherently more difficult to connect the small-scale DG.

171. Horizon Networks supports a new application process for large-scale DG, this could address the current problems with the Part 2 process.

Question	Comment
Q48. What are your thoughts on adding a new DG application process for large-scale DG to Part 6? Please provide examples in support of why you think change is or is not necessary.	Horizon Networks agrees that a new connection process for large scale (at least 1MW) DG would be beneficial. These connections are incredibly complex and require longer timeframes and more technical analysis (internal and external) in order to connect to the network. In many cases these generators also need lead-times in order to be physically built, so unlike rooftop solar, these DGs will not be 'losing out' by allowing additional time for the approval process. Horizon Network also notes that it is typical for large scale DG to consume more than the current application fee on internal resources to process the information request. It would be beneficial to update the regulated fees as recommended in paragraph 142.
Q49. If you think a new application process should be added, where should the threshold be and why?	1MW should be the threshold. This reflects the point at which the generator may impact the operation of the grid and could be subject to dispatch by the system operator.

Subsection 7 Review the priority of applications clause in Part 6

172. The Electricity Authority raises concerns that there may be a 'race for capacity' by speculative DG applications, which can result in an inefficient allocation of resources.

173. Horizon Networks notes that the current low cost of DG applications (lower than the cost to the network in assessing the applications) means there is an ability for speculation to occur. Speculators are less likely to seek to reserve capacity via the application process if they need to face the true time and resource costs for assessing their applications.

Question	Comment
Q50. What are your thoughts on reviewing the priority of applications clause in Part 6?	Horizon Networks agrees that EDBs need to have a clear priority framework to assess applications. However, Horizon Networks considers that there needs to be the ability to differentiate between "firm" applications (has the ability to build the proposed DG) and "non-firm" applications (is seeking approval ahead of knowing if the DG connection is viable). Having a process that requires DG applicants to have a "firm" ability to connect DG and clear intention to do so ahead of approval will support effective assessment of applications and focus EBDs limited resources on the applications that are most likely to go ahead.

	Additionally, as noted in paragraph 142, having the ability to align fees with Transpower's connection process[25] will ensure there are no incentives to inefficiency connect to the grid or local network.

Subsection 8 Strengthen Power Quality standards

174. It is critical that the connection of DG does not interfere with the frequency and voltage of electricity supplied to consumers on the network.

175. The latest version of AS/NZS 4777.2 includes improvements to power quality and power quality response modes.

176. Horizon Networks supports the use of modern inverter standards that have been updated to help address the challenges of increasing amounts of distributed generation.

177. Horizon Networks notes the Part 1 process is not being used on our network. All DG applications with a size of 10kW and below were made under the Part 1A process, with compliant inverters.

Question	Comment
Q51. Should the AS/NZS 4777.2:2020 Standard be mandated for inverters in New Zealand? If so, how should this be accomplished?	A variant of AS/NZS 4777.2 2020 should be mandated for all new connections made under the Part 1 application process. As this is a joint Australian and NZ standard, Horizon Networks expects the voltage settings will appropriate for New Zealand.

Subsection 9 Review Part 6 prescribed maximum fees

178. The Electricity Authority proposes to review the prescribed maximum fees in Part 6 and notes these have not changes since 2015.

179. Horizon Networks notes that the maximum fees have not been reviewed since 2007, and no longer reflect the costs associated with processing applications under the Code. This cost differential results in consumers cross-subsidising DG applications.

Question	Comment
Q52. What are your thoughts on the Authority reviewing the prescribed maximum fees in Part 6?	Horizon Networks agrees these fees should be reviewed as a priority. Horizon Networks notes these are maximum fees, and the actual fees charged by EDBs should reflect the true (average) cost of processing the application. For Part 2 applications over 1MW, Horizon Networks recommends the applicant face the same application fees as if connecting to the grid. This will ensure that the costs of processing the application are recovered and there are no incentives to inefficiency connect to the grid or local network simply because of a lower application fee. For other fees, such as Part 1A the charges were relatively arbitrary and for some Part 1A fees an assumption was made that costs to the EDB would be halved due to the streamlined process. This assumption can now be replaced by empirical evidence so that costs can reflect the true (average) cost for connection. By applying an average cost to DG for the Part 1 and Part 1A processes, any cross-subsidies for connection of small-scale DG will be between DG applicants and not from consumers via EBDs operating expenses.

25 https://www.transpower.co.nz/connect-grid/our-connection-process

	In addition to reviewing the fees to ensure they reflect the true cost of processing the application, there should also be a regular CPI uplift to the maximum fees. This reflects the inflationary pressures experienced by EDBs on an annual basis and can help prevent 'inflation creep' and the need for regular reviews.

In conclusion Horizon Networks supports improving access to information and regulatory settings that will enable NNS to be an effective tool to manage EDBs networks

180. Horizon Networks supports any move towards improving access to information and regulations that will improve EBDs ability to manage their networks.

181. This can be best achieved thorough:

- The Commerce Commission allowing EDBs to recover the cost of flexibility services through a 'reopener' process that increases the MAR.
- Regulating MEPs, including access to information and configuration of metering to support flexibility services.
- Centralising data access, so there is a single point of access for all data and information.
- Reviewing Part 6 of the Code to ensure it is fit-for-purpose as the number and size of DG seeking to connect increases in line with decarbonisation efforts.
- Recognising that NNS is a new tool, and it use should always be evaluated against the other options available address network challenges.
- Give EDBs the flexibility to source internal and external NNS solutions so that costs to consumers can be minimised and risks can be effectively managed.

Yours Sincerely

Jonathon Staite
Regulatory Manager
Jonathon.Staite@hegroup.nz
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