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Powerco Limited

35 Junction Street
Private Bag 2065
New Plymouth 4340

0800 769 372
powerco.co.nz

Submissions
Electricity Authority
Level 7, Harbour Tower
2 Hunter Street
Wellington

Via email distribution.feedback@ea.govt.nz

Tēnā koe,

Powerco welcomes the Electricity Authority exploring how the distribution sector may evolve over the coming decades. Powerco is one of Aotearoa's largest gas and electricity distributors, supplying around 340,000 (electricity) and 112,000 (gas) urban and rural homes and businesses in the North Island. These energy networks provide essential services and will be core to Aotearoa achieving a net-zero economy in 2050. Distributors will have a role to play in delivering and/or accessing new services in the market to efficiently deliver safe and reliable electricity to consumers.

Defining new services, and the market mechanisms to price and procure them is a task the Authority is well-placed to support. The Authority's paper canvases a range of topics related to these market arrangements or needs. Our summary position on the five themes is below, with our top-two priorities highlighted:

Priority	**Equal access to data and information**	• Focussing on access to consumption and power quality data will improve network planning decisions • Forecasts of flexibility opportunities are part of a broad set of decisions driven by network capacity, security, reliability, and resilience • More information will enable more informed decisions from all stakeholders – it's broader than congestion and EDB investments. We have launched a network capacity map to support generation connection decisions[1]
Priority	**Distributed Energy Resource standards**	• Support Part 6 review (process, fees, pricing principles) • Broadening Part 6 from DG to DER is appropriate in principle but there will be complications to address
	Market settings for equal access	• Support the Authority's proposal to monitor assessment and adoption of non-network solutions. Project overviews could be a useful template for conveying how options are assessed and a preferred solution chosen
	Capability and capacity + Operating Agreements	• Support a low touch or future assessment of these two issues so Authority resource can be directed at higher priority issues. The Authority's views on collaboration ideas always welcome, though a formalised process unlikely to be efficient right now. Contract development is a relatively small part of the entire process and too early (inefficient) to standardise agreement terms.

[1] See https://www.powerco.co.nz/get-connected/distributed-generation

Our responses to the consultation paper questions are attached. We support the Electricity Networks Association submission. If you have any questions about this submission, please contact me at Andrew.Kerr@powerco.co.nz.

Nāku noa, nā,

Andrew Kerr
Head of Policy, Regulation, and Markets
POWERCO

Attachment 1: Response to Authority questions

Equal access to data and information

Our summary views on this general topic from our 2021 submission were:

- Maintaining a focus on the nature and scale of the decisions being made by market participants and the information that informs them will support the case for specifying reporting of particular data sets
- We agree that more information will enable more informed decisions from all stakeholders – power flow data, congestion data, and hosting capacity are part of the information set
- We are keen to work with the Authority and stakeholders on what data (congestion or otherwise) will support investments by procurers and suppliers of services in the electricity market.

Q1. Do you see value in 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 delivering interoperability in a New Zealand setting?

Yes. We see value in leveraging the analysis and thinking arising from the UK working group, and would support the proposal in principle, with the proviso to recognise the significant differences in the two jurisdictions.

We support further investigation of the digital spine concept tailored to the NZ context. This real time operational layer providing cross industry standardised communications, protocols, data formats, schemas and interfaces will be highly complex and vital to deliver dynamic dispatch. At the limit, the full value of flexibility will be deliverable with automated 2-way interaction with every resource in every installation. Given this would need to happen across multiple industry actors, and that system security is dependent upon its effectiveness, the reliability and robustness of all components, plus the system as a whole, would be critical.

Q2. Does this capture the key data needs for distributors to make informed business decisions that will unlock the potential of distributed energy resources (DER) for the long-term benefit of consumers? If not, what data is missing and what would it be used for?

We support the identified data needs. Simple, low cost, secure access to consumption data will return immediate and substantial benefit to consumers. This data is one of many sources we use to assess and trade-off options in our planning processes to meet capacity, resilience, and reliability requirements.

A key example of additional data needed to light-up DER capability is in the low voltage network eg asset and network connectivity data, ICP connection info (phase, point of connection etc). As well as the date, there are the systems to use it. The costs of capturing, storing, and using this data is included in Powerco's latest asset management plan forecasts which are assessed by the Commerce Commission. The combination of the data and systems will align the quality of network master data with the need for rising DER penetration, allowing detailed network modelling to produce the necessary congestion and capacity data.

As an alternative to expensive field data capture, smart meter GPS locations could be leveraged by EDBs to verify or infer the correct network connection point for each installation. It may also be possible to leverage power quality (PQ) and event data, if adequately time stamped and of high enough resolution, to back populate some phase information and possibly even some missing asset details.

Either way, the outcome being targeted by Powerco is the same: a full and complete model of the network down to each LV installation. Access to comprehensive smart meter data, especially consumption data, provides EDBs with much more accurate assessment of loading patterns (demand profiles). This can then be used to forecast future loading patterns and produce robust estimates of simple congestion data at any point on the network.

Independent of unlocking the potential of flexibility, there is also an immediate use case for meter status data (last gasp, first breath or ping) functionality. The value proposition is clear and immediate through reduced fault or outage response times, for both HV and LV events. There are communication and technical hurdles, but successful prototypes have been evidenced already (with data from meters right into operational control room). We therefore recommend that meter status data be separated out from the general PQ data and considered in its own category of operational data.

PQ data is also valuable for EDBs, both to reverse engineer some of the data gaps in the master network data, but also to quickly pinpoint latent power quality issues, particularly voltage exceedances in the LV network. A challenge here is variance in the type and specifications of data that can be provided across the various meter types, and MEP providers. Industry alignment on a common data specification will be valuable as many use cases are still future concepts. This context of PQ data contrasts with consumption data, where the use case, data type, and specifications, are tightly defined and there is little or no variation.

As a first step **we recommend cross-industry work to define the minimum viable product that the majority of all meters and MEPs can provide** and that can practically be leveraged by EDBs to produce value. This should include: current (I) and voltage (V) sampling, sample rate and/or any statistical aggregations of these (eg averages, max). KVARh and/or power factor are invaluable data for tuning network analysis, and could be at half hour resolution to complement kWh data. Capabilities around harmonic or transient data capture will be challenging so better considered after the basics are sorted.

In para 4.55 the Authority indicates it has had feedback that ICP level data is not always necessary. We agree, but more importantly sometimes it is necessary (or at least better). Our view is that the best data should be used for decision-making. We would recommend, as the Authority proposes, that all consumption data be fully disaggregated to ICP level. We have engaged with industry for several years on this topic and remain open to understanding any problems with this approach.

It is indicated in some places (eg Distributors Data Need 2 - Page 31) that EDBs require knowledge of the location of "non-exporting DER". By contrast, other parties such as traders (eg Flexibility traders Data Need 2 – Page 33), are suggested to need DER. We would like to understand if this is an intentional distinction.

Knowledge of the location and capability of DER (whether exporting or not) is critical to EDBs. This is an area of focus as they approach a density where self-sustaining network islands could be accidentally formed after an outage, thereby creating a safety hazard. We have had issues with some DG applicants failing to give notification of DG, or its livening, leading to gaps in our visibility as to which installations need to be isolated before the network can be safely accessed. Two-way meter data would be invaluable to mitigate these risks and confirm which installations have active devices capable of energising the network.

Flexibility will be used to address existing and future congestion, hence its value is dependent on forecast future demand and loading profiles. EDB access to historical consumption data is the first step as this gives visibility of existing loading profiles. This forecasting uses additional data like population movements, demographics, industry metrics, industry composition, changing customer needs and requirements etc. While this may be outside the Authority's responsibilities, it is noted here for completeness as additional "data EDB's require" to fully realise the value of flexibility. We commented on this in our 2021 submission.

Q3. Do you agree with the prioritisation of the key data needs for distributors? If not, why not and how would you suggest the priority is changed?

We agree that simple and cost-effective access to historical and fully disaggregated consumption and PQ data is the immediate and highest priority of those identified.

We recommend that meter status data (eg last gasp, first breath, mass ping functionality) be separated out from the general PQ data and considered in its own category of operational data. This real time meter status data should be given med/high priority, as it has a high value proposition that can be readily realised, but is subject to technological standardisation to enable seamless cross platform (and across business) data transfer in real time.

Historical PQ data, and the definition and standardisation, should be a medium/high priority. This is particularly important to verify if it's a viable option for back populating some data gaps in network master data, so that complete and accurate network models are available to produce reliable congestion data.

We believe that the potential safety consequences of the issues related to poor visibility of DER are such that they are a priority too. By contrast, addressing incomplete records of the location of DER is probably a lower priority.

Q4. Does this capture the key data needs for flexibility traders 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?

We support traders in flexibility having access to data which will assist them and customers/investors realising the value of the services they provide to the market. Although the Sapere report indicated that most of this value is in the wholesale market, it's important that any value in the distribution network can be realised too. Given this, a starting point is that flexibility traders are subject to the same requirements as distributors around data eg secure management, appropriate use, and the same if not more rigour is applied in regard to privacy, security and permitted uses. Similarly, we support discussion of the terms that would govern data being supplied from flexibility traders to distributors.

As the Authority notes in the consultation paper, there appears to be a very real risk that both consumption data and data around the location, size etc of DER will lead to unsolicited approaches. Rather than manage for 'the bad', this risk is better managed directly rather than by preventing the data being made available for 'the good' eg flexibility traders being a member of Utilities Disputes.

Congestion data

We agree that network congestion data will be one of the essential data sets for traders, especially as this can progressively be made more granular (down to every connection node eventually) and quantified (monetised value/cost). In addition to planning information, this information can potentially provide guidance as to the nature and scale of potential value for network congestion (a bit like looking at point-in-time congestion on a motorway at the same time as the long-term forecasts and plans for that road and any others).

Understanding cost/value is equally important: the quantification of future congestion cost can be reflected in network prices. The signal can reflect either the costs of constrained supply (congestion) or the costs of an optimally timed future network investment to alleviate those congestion costs. Our pricing methodology is making a start, focussing on aligning the structure and pricing differentials used for time-of-use pricing with the future investment costs. This is an opt-in open-access option supporting provision of network services. We expect this can be augmented with shorter term bespoke contracting options that are more closely linked to the specifics of an investment project and also available to any trader. The end-game is a future portfolio of pricing/quality options for all parties which are co-optimised to, at a minimum, support a lowest cost provision of network services.

Powerco is automating the production of quantified congestion data across the high voltage network. Achieving this for the low voltage network is dependent upon improvements in data, both network data and loading data, as detailed in this consultation. There remains some cross industry work to do to effectively communicate such granular network information, possibly requiring standardised data formats for network data.

Consumption, PQ, and DER data

Our focus is on offering traders in flexibility the key information we understand they need, which includes granular and quantified network congestion data.

We are keen for the Authority or flexibility traders to explain how the other data items identified (raw consumption data, PQ data and DER data) support the uptake of flexibility. There is an inference that equal access to data is the goal; but access to data shouldn't be about 'all participants having the same data' but rather about 'all participants having the data appropriate to their needs'.

There are also inferences that flexibility traders can use this data to identify areas of the network that may be subject to congestion eg in "…this enables flexibility traders to identify the areas of a network that will need upgrading before others and offer solutions accordingly…" (see 4.65a). We agree that this data can provide a guide, along with asset management planning and other documents, to flexibility traders about the potential role for solutions to support networks. However, this congestion data is not likely to be a one-stop-shop for a trader to assess upgrade needs. Network upgrades can be made for a range of reasons other than capacity eg resilience, security, or lifecycle replacement, and the forecasts of all of these are embedded in network models.

A core role of the EDB is to produce network congestion data along with proposed network investment plans in a granular detailed format. While it is in our vision to make our network model available in future, this is dependent on first addressing data quality issues, and the industry standardising the means to exchange model data. We expect to engage with traders to support them upskilling in this area.

The use case for providing DER data (location, size and functionality) to "flexibility traders" (as distinct from traders generally and the customer's chosen trader specifically) is questionable. We support the current retail model where customers choose the trader and plan according to what offers them the most value and has a range of customer care obligations. If any trader wishes to offer a competitive alternative, then the framework already exists for that. Importantly, the customer must initiate the engagement. We are curious to know how the Authority and traders envisage managing the competitive dynamics if DER or consumption data is shared with traders other than the customer's chosen trader.

If an EDB, via any trader, wishes to encourage flexibility investment and deployment, they can signal this via their (standing) prices and bespoke service provision opportunities. An effective retail market, as already exists, should then produce the right uptake of flexibility given trade-offs for providers (consumers or otherwise) with their other options. This ensures maximum competition as all traders have the opportunity and access to network flexibility value. The customer has maximum choice, but again retains the rightful privilege to respond to appropriate broadcast marketing that doesn't leverage their own private information to make them a target.

We agree that real time data access to flexibility traders should not be necessary for some time. Real time congestion data would eventually be reflected through a dynamic distribution nodal price, and to evaluate this the distribution price setter eg DSO, would obviously need real time two-way communication with installation metering, and potentially bidding information. This is obviously unachievable without a complex "digital spine", and hence is beyond what is immediately realisable across the industry.

Q5. Do you agree with the prioritisation of the key data needs for flexibility traders? If not, why not?

As noted in Q4, we believe the priority information for traders in flexibility is access to quantified, granular network congestion data and network investment plans. Perhaps most important will be how that information translates to current or future service provision opportunities.

The primary means by which the Authority could support this is via any standardisation of data formats. As set out in Q4, and recognising their industry role, there does not seem to be valid use case for providing "flexibility traders" with access to consumption, PQ or DER data.

We agree that real time data is a future requirement only, dependent on the establishment of supporting infrastructure like the digital spine and the confirmation of roles and responsibilities in a future dynamic pricing environment.

Q6. Do you agree that the Authority should amend the Data Template to address the above issues to improve its workability? If not, why not?

We agree that the Authority should amend the Data Template to incorporate the proposed changes, and particularly the ENA/ERANZ variation which we note is beginning to be used as a de facto base standard although in slightly altered bilateral forms. This is consistent with our engagement with the industry and Authority over the previous few years.

We agree with the Authority (at 4.79) that a priority is for consumption (and PQ) data to be readily combined with network topographic, asset and other data. Without this, the effectiveness of this data is completely compromised.

It is also important that the "reasonable costs" provision be applied to both retailers and MEPs. Furthermore, the term "reasonable costs" must be well defined and/or provide mechanisms by which EDBs can verify and potentially challenge the costs presented. As noted, the MEP is in a monopoly position and normal commercial negotiation is therefore thwarted, meaning well-crafted provisions would be advantageous to give transparency of actual costs, and some negotiating power, or confidence in the reasonableness of the costs, to purchasing parties.

Through our strong retailer relationships, we have a large percentage of our network covered with agreements concluded outside the DDA. Many other EDBs may not have the same capability, especially with a wide range of traders on their network. We would therefore fully support measures to streamline the supply of consumption data directly from MEPs, at clearly established and appropriate "reasonable costs" via the Data Template. Changes to the frequency of access have been addressed in the ENA/ERANZ variant that we are using.

Directly accessing high-quality data from MEPs, with appropriate commercial agreements in place to cover all parties' responsibilities adequately, would be appropriate and efficient.

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?

Frequency of data, permitted joins (Combination Schedule), etc should be clarified and leverage working evolutions of the ENA/ERANZ Agreement.

Q8. Do you agree that this is an issue? If not, why not?

We agree there is an issue with high administrative costs associated with needing to establish many retailer permissions, even for retailers with a very small number of customers.

An enduring, efficient and sustainable approach would be preferable via a Code amendment that allowed EDBs to work directly with MEPs for access to consumption and PQ data. At the same time, this must ensure retailer's responsibilities, especially as the primary steward of customers' private data, must be adequately recognised and accommodated.

Where an EDB cannot secure every retailer's permission, it can interpolate missing data. However, this is suboptimal from an efficiency perspective ('good data, good decisions') as it creates additional overhead for every EDB served by that retailer. If that retailer specialises in a particular type of customer whose characteristics (profile etc) are markedly different to the average, then approximations will be inadequate.

Applying the Data Template and access framework to flexibility traders will create a tension with incumbent retailers (potential competitors) who retain ultimate responsibility for the secure and appropriate use of the customer's private data for appropriate purposes, and who do not have any contractual arrangement with the Trader. Access to this data should be restricted to customers with whom the trader has a contract or agreement.

Q9. Should the Authority amend the Code to clarify that MEPs can contract directly and provide both ICP data to distributors (and flexibility traders) for permitted purposes? If not, why not?

We agree that the Authority should amend the Code so that EDBs can contract directly with MEPs.

As retailers are formed, merged, and sometimes cease, and as consumers move between these retailers, managing the pool of ICPs associated with each retailer will impose significant additional complexity on the access to and management of consumption data. Conversely, MEPs (or rather the meters and metering systems they own and operate) have a much more enduring relationship with an individual ICP (second only to the EDB). Of the options, it makes sense that EDBs work directly with MEPs for access to and the ongoing provision of consumption data for codified purposes.

As noted on earlier questions, we are keen to understand more about the use cases (or permitted purpose) for flexibility traders to need access to consumption and PQ data. Some mechanism to bind flexibility traders to industry rules and existing agreements similar to EDBs would be needed. Flexibility Traders can already and appropriately access an individual ICP data via EIEP13, once they are appropriately identified as an agent for the customer.

Q10. Should the DDA Data Template be updated to include Power Quality Data? If not, why not?

Yes, PQ data should be covered under the Code and Data Template just as consumption data is. Both have considerable value for network management, especially in relation to supporting DER uptake.

The definition of "PQ data" would need to be clarified. The provision would obviously be subject to what each meter is capable of and what is collected and stored by the MEP.

The usefulness of PQ data, and also consumption data, is related to the sampling /storage period. This again will be limited by meter capability, communications and MEP backend systems. It is highlighted here as the value proposition improves significantly with something closer to 5 minute sampling, rather than the half hour summation which serves the revenue metering purpose.

To be fully effective for all network management purposes, transient and harmonic data have quite demanding requirements, which may be beyond many revenue meters. It would still be worth exploring what data is available as some more immediate use cases like reverse engineering missing network data, could be extremely valuable to bring LV system data up to the required quality.

Our view is that PQ data should consider the following elements, and associated value propositions:

- Steady state sampled voltage: Identify areas of the network already nominally constrained; improved tuning of state estimation models, especially for LV systems[2]
- Power factor: or, as an alternative, kVARh metered over the same period as kWh
- Transient and event data snapshots: Identification of latent PQ issues. If time synchronised, events can allow inference of some missing network data, especially ICP phase connections
- Harmonics: Monitor growing network harmonic content and proactively address issues.

As noted earlier, we believe there is a precedent piece of cross industry work to define the PQ data specifications that are both realistically achievable given meter stock and MEP provider capabilities, and the value propositions realisable from each type of data.

[2] Note - Real time ping of communication status may be an effective way to allow EDBs rapid outage area identification. For this reason, we would recommend addressing this functionality independently of other aspects of PQ data

Q11. Do you think that the transaction costs associated with negotiating access to MEPs is a problem that the Authority should prioritise? If no, why not? If yes, do you think there is merit in developing a template to develop a default template to help reduce transaction costs?

Yes, we believe there is merit in developing a default template. Development costs can be minimised by utilising the evolving versions of the ENA/ERANZ agreements that have already been implemented.

Simplifying the process of negotiating data access would have a lot of value and should outweigh the work required to be done up-front. There are significantly fewer MEPs than retailers, but there are still multiple parties that each distributor will need to negotiate with individually under the status quo. Requirements should be consistent across distributors. Some distributors may have lower capabilities and/or requirements, but the types of data are distinct and straightforward to define.

Q12. Do you agree that MEP pricing for ICP Data (including Power Quality Data) and related data services is not unreasonable at this stage? If not, why not?

We agree with the statement that MEPs hold a natural monopoly position that leaves EDBs with no negotiating leverage or transparency. In the absence of action, this is likely to frustrate access to data, slow the overall implementation of flexibility and add unnecessary costs to consumers.

Our experience to date and best judgement (without transparency or ability to audit/challenge) is that costs are high enough to warrant some scrutiny by the Authority on behalf of customers. For example, our experience with the prices for consumption data is that it's not clear where extra costs are arising over what is required to deliver the same information for reconciliation and billing purposes. It could be that prices to retailers have been reduced to reflect the increased spread of costs – this is not something visible to us.

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?

Consumers will benefit from transparent pricing given the impacts it will have on EDB operating costs which are paid by consumers. Having 'off the shelf' pricing for smart meter data will significantly simplify and ease the process for accessing this data for EDBs. As it stands, EDBs must negotiate with individual retailers and/or MEPs with uncertainty as to the reasonableness or otherwise of the prices being quoted for this access.

More transparency over pricing, availability, and general terms to access data from MEPs would lower barriers for the use of consumption and related data. The amount of work and cost required end-to-end to access consumption, power quality or other data may be discouraging distributors from using the available data for the benefit of consumers.

Transparency is only valuable when coupled with a suitable test for reasonableness. If costs are demonstrable and reasonably recoverable that could meet the test for reasonableness.

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, we agree with the recommendation. Minimum standards might be more appropriate. There are multiple players in the MEP market and they should have the opportunity to innovate and offer services beyond the minimum standard. This should enable other parties to select when and what data they need, in standardised formats (much like EIEPs, but less formal) and at pre-determined, agreed and reasonable prices.

Q15. Do you agree that distributors' visibility of the location, size, and functionality of DER needs to be improved within the next 3–7 years to support network planning? If not, why not?

There is clear evidence that EDB's lack visibility of the location of DER. There is already uncertainty in the completeness and accuracy of records on existing DER.

There are a vast number of actors involved in a DG connection, and a low level of understanding of compliance matters. We have had particular issues with not being advised a DG has been commissioned and in some early cases not even being applied for. Inconsistency exists between our records and registry or retail records such as presence of 2-way power flow. The uncertainty around where DG is located, together with the rising penetration and increased risk of accidental islands being formed if anti-islanding protection is defeated, means the industry is needing to implement costly procedures to ensure any potentially DG capable installation is located and isolated before work on deenergised assets can be assured to be safe. This is an operational issue, not planning, but the serious consequences warrant improved attention to complete and trustworthy DER records, and Code/standards compliance by all parties.

There is a valuable existing DER (DR) resource in the ripple controlled hot water cylinders (HWC) on the network. One area of improved visibility for EDBs and retailers is where changes have been made internally to installations (e.g. cylinder replaced), the data indicating which installations are actively deploying this HWC DER resource is poor. It is hoped that consumption data can be leveraged to confirm some of these ICP records. More generally, requirements around DER visibility will benefit from considering replacements and refurbishment activities as well as installation.

In regard to uptake of new DER resources, EV chargers may be the first priority, but the immediate concern here is the EV charger as a significant load, rather than as a DER device. These chargers are available in a vast range of sizes/capacities, and if they do not exceed the installation's total capacity, the mechanisms are not in place for EDBs to review, or even be aware of, the charger installation. Larger capacity and unconstrained charging could rapidly cause LV network problems, particularly in residential areas where the size of an EV charger's demand could vastly exceed the assumptions on which these networks were originally built; i.e. conventional domestic appliances and expected patterns of use. Consideration is urgently needed to not only provide accurate information on the location and scale of EV chargers, but also on possible mechanisms to approve them and fairly allocate any costs.

It is expected that electrification will first congest LV systems as EV uptake and de-gasification (load congestion) and renewable generation (export congestion) increases. As penetration increases, together with commercial developments, the congestion will start to impact the HV system also. Effective network planning requires information to both forecast the accelerating rate of congestion, and the potential flexibility offerings to mitigate it.

Network Planning has a long term horizon, up to 30 years, but planning decisions impact investment and prices immediately. The necessity for data to support Planning is an immediate priority. We would suggest "DER visibility" needs addressing before the 3-7 year timeframe.

Obviously planning is heavily dependent on forecasting, and the data which can inform that. Data critical to network planning is as much about future DER (and demand) as it is about existing DER or demand. There are numerous data sources that assist in improving the accuracy and variance of forecasting, both in terms of organic population-based growth and electrification. Most of these data sources are not under the direct influence of the Authority and Code, but are mentioned here for completeness and to note that even with improved DER data, EDB's need a range of additional information to drive effective network planning, particularly in the uncertain environment created by electrification, technology and changing patterns in society. This is immediately evident in our move to probabilistic (statistical) approaches to planning and more systematic use of scenarios (multiple diverse futures). Linkage here can be made right back to earlier questions around access to consumption data, and the necessity to be able to join this to other data sets. A key forecasting technique is to detect trends in electrification uptake, map that to installation premises and then join that to territorial authority and statistics data to help forecast the future uptake.

Q16. Do you have any views on the type and size of DER that needs more visibility?

As noted in Q15, we see a requirement for data on DER in relation to both its uncontrolled demand/injection impacts, plus its flexibility offerings. For planning purposes this is more about future DER; for operational purposes it is about existing DER.

EV charging appears to offer high value in terms of mitigating the demand increases brought about by electrification. In this case EV charging is both the problem, and a potential part of the solution (in its DER capacity). As noted in Q15, we believe there needs to firstly be a robust framework for deployment of chargers related to their material demand impact or unconstrained capacity. Then there needs to be appropriate information on their flexibility (control) options and usage of that functionality.

Energy Storage Systems (static batteries) are similar. While charging of these is unlikely to occur at peak periods in the immediate future, they need to be recognised still as a significant demand device, and flexibility device, with planning assumptions reflecting how this could evolve over time for a range of potential drivers.

In terms of visibility of these two main DER resources, we would suggest there is a need for:

- Knowledge of the location and size, being essential to effective and safe network management (operational and planning). This could be called "network master connection data"
- Understanding of the patterns of use. Consumption (and injection) meter data that indicates trends and patterns from which forecasting can be derived
- Standardisation on capacities, functionality, interfaces and communications will be critical to a "digital spine" and dynamic pricing future, or even immediate deployment. To the degree there is not standardisation, data will be required on each of these aspects for each installation, and will need to be accessible to all parties.

Size of DER should not strictly determine vastly different data or visibility requirements. For safe and effective management of the network, it is essential networks are always informed of the basic DER unconstrained capacity or size (in both power flow directions).

DER size is also more a matter of 'horses for courses'. The size of a DER should be considered against the size of the corresponding installation and its demand. Large commercial EV chargers are likely to be deployed at large capacity commercial installations. Intuitively, for optimal overall economic benefit, domestic EV chargers should be sized at that which is complimentary to residential installation demands and capacity. This balance is generally seen playing out already in the solar PV (DG) uptake. A residential PV installation tends to install a capacity complimentary to its demand, and which is reasonable considering roof space. Similarly, ESS batteries in domestic situations are starting from the point of mitigating consumption (self-supply). Commercial installations can sometimes violate these principles, but if they do install large capacity and it exceeds the installation capacity, the current industry connection and upgrade processes tend to provide sufficient information for networks to manage the increase.

A future unknown is terms of DER visibility is the extent to which consumers actively engage with energy markets, with a possible scenario that their capacity and usage patterns aren't complimentary to network capacities and assumed use. Network planning and pricing will need to adapt to reflect this. These underlying assumptions do not hold true for some possible future ESS and EV charger scenarios.

Uncontrolled DG, mainly PV, although not considered flexibility because it is uncontrollable, still has some benefit in reducing demand, especially if the network is constrained. In future, PV output will be very dynamic and network management will require real time forecast of output. To do this, EDBs will eventually need their operational (ADMS) systems to be able to forecast the real time output of masses of small (non-monitored) PV. Predictive models in ADMS systems could be improved with data on the PV cell orientation (bearing and pitch etc). To some degree this data may be inferable, or estimated, from analysis of historical consumption data, but this will be less accurate as PV cell output is obscured by the installation demand. This is not considered a high or immediate priority, and is potentially something we could wrap into our connection processes within the existing Code framework.

Vehicle to Grid (V2Grid) are a special case of DER that needs considerable cross industry and regulatory consideration before any mass rollout could be anticipated. Network operators must know what installations have devices capable of energising the network. V2Grid, being effectively mobile ESS systems, cannot currently be permitted to feed into any AC system at will. As an interim measure, those wishing to deploy V2Grid could do so if network connection (and injection) was limited to only those installations where active DG had been approved through normal Part 6 processes. Or, connection only to AC circuits in the installation that were entirely isolated from the network (no grid tie). It is essential EDBs are advised of any installations where V2Grid cars are active and grid tied. Given the intrinsic ability of cars to move between installations, this requires a robust industry framework before uptake becomes widespread.

Q17. The Authority acknowledges that definitions of 'real-time' vary, please explain what real-time data means to you.

Timing depends on the application. Real time intrinsically serves network operational use cases. Each use case has differing latency requirements.

Half hourly consumption (revenue) data, being historical with multi-day lag, is not directly relevant to network operations. Bulk consumption data is really only used to examine historical patterns in usage that inform trends and then support forecasting, planning and pricing, so historical is probably adequate for consumption data. Ideally next day, but this is not a priority for this use case.

Operational systems like ADMS/Scada typically need to poll for network state variables every few minutes. As electrification picks up, the capability of these new DER devices to rapidly alter power output (or consumption), and hence rapidly change network conditions especially voltage, will drive a need for sub-minute data in future.

Last gasp type data would need to be virtually immediate; delays would be more associated with the communications and integration across multiple systems. It is the provision of this data, rather than the latency, that is probably important.

We believe the focus of real-time discussions should be on early provision of effective cross industry communications and data interfaces so that network operations centres could effectively identify outage areas (using last gasp or polling). These should be sub-minute in completing the data collection.

The potential long term future scenario of real time dynamic ICP nodal pricing would require sub-second, 2-way, iterative, mass communication to distributed devices. Systems to achieve this would be of the nature of the internet, but importantly would need greater reliability since system security could be dependent on communications systems remaining functional even with depressed voltage. This should be a focus of the "digital spine" investigative work.

Q18. Do you agree that access to 'real-time' consumption and Power Quality Data won't be needed for at least five years?

We agree that access to 'real-time' consumption (half hourly quantities for revenue metering) data won't be needed for at least five years.

As noted in Q17, there is immediate value in real time state variables, like voltage and current, being provided into real time network operational platforms. Where it is possible, these should be leveraged as soon as they are available and the cross-industry communications and data platforms can be established.

The development of business processes and systems (e.g. ADMS) will be happening in the next 5 years. While the data isn't strictly needed until these systems are operational, the sooner that these types of smart meter data can be made available to EDBs, the sooner it will be possible to design the interfaces and integration, and the sooner benefits will start to be realised.

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?

We do not see flexibility traders as in competition with EDBs, but rather as partners: potential suppliers of a service. We therefore fully support traders having access to any information that is useful to their purpose and role. We cannot see where ICP data fits into that as it relates to supplying network services given the EDB is the buyer. We can see that it could be useful for other market purposes, though that is not the context in which this question and discussion is framed ie EDB regulatory settings.

Historical consumption data is vital to EDBs, so as to inform demand patterns and assist forecasting of future demand, injection and potential flexibility in that. When applied to network modelling, this forecast network loading can produce network congestion data, investment plans and pricing. It is these outputs of an EDB's functions that should be far more valuable to traders in flexibility than the raw consumption data of individual consumers because it is those plans and pricing that drives commercial value.

Provided that any trader has established a relationship with the customer at the ICP and is therefore acting as their nominated agent, we agree that such trader should have the same level of access to that ICP's data as the incumbent retailer and the EDB. In such case, any trader must ensure appropriate care and security in managing customer data. As the Authority notes, it will also be important that access to such data does not result in widespread "unsolicited approaches".

Consumption data patterns can be used to infer the presence of existing DG. But this usually only identifies uncontrollable PV through evidence of its daytime export patterns. Controllable DER, which is likely to make more subtle modifications to the existing installation demand profile, is harder to detect from overall gross consumption patterns. In any case, the detectable changes to a profile which might be the result of DER deployment, would only serve to inform where existing DER was already in use. If traders in flexibility need to know where existing DER is located, controllable or otherwise, then the appropriate master data (static data) related to the installation (ICP) should be identifiable through public channels like the Registry.

A further question is "what value is there in knowing which installations have DER". New DER combined with market and retail/flexibility trader capabilities will offer new value opportunities in response to market pricing signals (whatever that may be and for whatever service is valued). Yes, we want customers to get the most out of their DER investments, but preferably through their free choice around provider and plan. Giving traders information about the location of DER must be bundled with guidelines or expectations around unsolicited approaches (as is the case with Registry information).

Only time will tell if there is a distinction between traders in flexibility and traders generally (retailers). And does this distinction or separation, and any subsequent industry architecture, add or reduce long term value and service to customers.

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.

It is not clear how the Data Template could be modified so that flexibility traders could use it, given that the flexibility traders may not be participants under the Code, nor are they necessarily party to the distribution agreements in place between retailers and EDBs. Extending the template to flexibility traders means addressing privacy, retailer/customer contracts, customer consent, and the obligations in Appendix C of the DDA eg audits.

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?

Retail traders, and ultimately consumers, will benefit greatly from access to granular data on forecast network congestion. It is unclear if it's a 'need' because it won't automatically translate to a commercial value proposition as it is only part of the considerations used to assess network options. Perhaps it is forecast congestion data and potential network service requirements that is of more use; we plan to align forecast congestion (what we call "investment needs") with probabilistic based planning and pricing (including NNS procurement) and make that information publicly available.

As noted in the consultation, the Commerce Commission is also looking at improved methods of sharing EDB investment proposals and needs. This may initially expand on what is in Asset Management Plans. Our intent is to provide even richer information on public portals, potentially in graphic and tabular format, to traders, customers and the market generally, and we are working on building the internal capabilities for this.

Q22. Are there any other issues preventing distributors from providing granular current and likely future congestion data?

The issue is not so much "preventing distributors" as much as the significant uplift in data and internal business capabilities.

Automated production and sharing of this data is a new business capability. There are also dependencies on access to data, as discussed earlier. New capabilities touch on the need to manage large volumes of high quality data, integrating this with high processing modelling platforms, and sharing securely on public facing portals, via agreed interfaces, formats and protocols

Powerco has a goal to achieve this for the high voltage network within 3 years, but the data issues associated with the low voltage system will require significantly longer. Of note, is that the total flexibility value due to network congestion for any customer/ICP is the sum of congestion elements at all levels of the distribution network. While the LV network has historically exposed little congestion, it is here where electrification's impacts are expected to hit first.

The highest priority is support for EDBs accessing accurate and complete data to enable production of congestion information (Q3-5). Data EDBs particularly need include consumption, PQ and support to ensure LV network models (the master network data) are complete and robust.

Notably, congestion data is always a forecast from models using numerous assumptions, not least the demand forecasts, and in this respect will require forecasts of load, generation and DER in future. Our probabilistic planning approach, effectively a statistical customer value approach, requires high iteration modelling of network future state under a vast number of future scenarios, loading patterns, uptake assumptions, and future network configurations. Traditional planning techniques, tools, roles and skills all need transformation to achieve this. New software systems are required, and integration of these with high volume data platforms. This is transformational; not incremental change. The timeframe of 1-3 years aligns with significant progress being made.

Data sharing for decision support by 3rd parties is the other area of development across industry. This data is no longer in a format that it can be included in a text document like the AMP. It requires graphic and tabular transfer or publication of very large and complex data sets. Individual points on the network must be consistently referenced across different businesses requiring standardisation of network models (formats, IDs, protocols and interfaces). These things cannot be resolved entirely just by the EDB, but require cross industry work eg Flexforum.

By way of explanation, the following are the items that need consideration to enable us to build the capability to automate the production of granular congestion data:

- Completion of all ICP information into the LV and HV network models
- Completion of LV network models themselves (connectivity and conductors)

- Automated analytic platforms to execute the billions of power flow solutions required
- Automated generation of full and complete network model, suitable for both power flow analysis and topology processing
- Building of the congestion models themselves, the assumptions/rules, and pre and post processing data manipulations
- Complete consumption data to be able to classify connections according to their profile and network service levels
- Improving data on existing DER deployment
- Automated forecasting of future demand (and profile), at full granularity. Also new models for forecasting generation and DER
- Integration of the network model with asset and reliability models (some of these still in early development too)
- Completion of work on defining appropriate values of lost load and capacity (willingness to pay)
- Standardised means of sharing network information, both tabular and graphic
- Building the required external facing portals, systems and interfaces
- Building up the internal skills sets, and developing internal systems for data and analysis, plus integrating process, roles systems
- Cross industry agreement, with potential industry standards and guides, on key parameters & assumptions that are used in determining congestion value
- Retail and other businesses to work with us to both create seamless data exchange but also correctly interpret and apply congestion value data.

In summary, there are a host of asset information, business process, customer interaction and business capability challenges to address to deliver the end game: provide accurate and meaningful network congestion information to third parties, particularly at the lower levels of the distribution networks.

Powerco supports the provision of this information. It is our vision to ultimately share our base network model and forecasts alongside our estimate of future congestion, and to allow other industry partners (especially retailers and their customers) to make their own estimates of future congestion, and thus inform their own investment decisions particularly around DER.

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?

This is a tricky question to respond to as it combines flexibility trader understanding of network congestion (which can have many forms) and the how they might use DER to respond. Flexibility traders will be able to offer services in addition to those related to network congestion. Where it is a network-related service, the trader would likely be responding to a 'buy' request which is linked to network congestion, but not necessarily solely based on it.

Q24. Do you have any views on the type and size of DER that flexibility needs to have improved visibility?

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 Authority has the expertise and judgement as to which approach would be better. For simplicity's sake, our preference would be for the existing registry to be expanded to capture improved DER information on a per-ICP basis, but we accept there may be challenges to doing this rather than developing a new registry specifically for DER.

Q26. Do you agree that the Authority should prioritise work on addressing the other issues outlined in this paper?

Q27. Do you agree that flexibility trader access to real-time congestion and ICP data won't be needed for at least five years?

Q28. Do you agree that model privacy disclosure terms are appropriate?

We agree that the Authority's proposal to develop model privacy disclosure terms for ICP data is appropriate.

Q29. Do you agree that model privacy disclosure terms would facilitate data access?

To the extent that model privacy disclosure terms make retailers and MEPs more comfortable providing access to ICP data to EDBs and third parties, yes, ENA agrees these would facilitate data access.

Q30. Do you see any practical issues with this proposal?

We do not see no practical issues arising from this proposal.

Q31. Should the Authority create model terms for distributors and MEPs as well given the range of data being collected through smart meters? If not, why not?

Given that the model terms that would apply to EDBs and MEPs are unlikely to be substantially different to those that apply to retailers, it would seem to be little additional effort, and helpful, if these model terms were expanded in this way.

Q32. Would the industry find it helpful for the Authority to conduct workshops on privacy preserving/minimisation techniques?

Yes, it would be helpful for the industry if the Authority facilitates workshops on privacy preserving/ minimisation techniques.

Market settings for equal access

We are excited about the role non-network solutions can have meeting Powerco's, and Aotearoa's, electrification needs. We have shared information about our processes, including contract terms, across the industry. This information is public and collated across all EDBs on the ENA website https://www.ena.org.nz/resources/edb-requests-for-non-network-alternative-services/.

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?

Powerco will soon be reporting on our approach to how we manage our energy networks given climate-related risks. This will align with Aotearoa's External Reporting Board (XRB) Draft Climate-Related Disclosure Framework, which is based on the international Taskforce on Climate-Related Financial Disclosures (TCFD). Core to this is developing challenging but plausible scenarios posed by our changing climate and our drive to decarbonise our economy. These scenarios then allow us to identify and prioritise our physical and transitional risks and opportunities along with financial impacts. Both the scenarios and reporting will be public. This is to better understand the resilience of our business models and strategies and ensure climate related information is routine considered in our planning as we transition towards a low emission, climate-resilient future state. This is the broader context for how we consider asset management planning, and where NNS can provide a supporting role.

We understand and the Authority's focus on NNS and we support their use when it's the right option across the many criteria we consider. We agree with the Authority that the scale of the non-network uptake is relatively minor at present. Importantly, there is sector-wide work eg via the Flexforum that is looking to breathe life into these options given the complexity involved. In this context, a transparency/monitoring approach from the EA is sensible.

Option 1: agree with Authority's comments in para 5.36 that distributors are alive to the issues.

Option 2: Funding of trials that are risky to consumer and network outcomes is worth exploring as it can only enhance the solution set, whether the trial succeeds or fails.

Option 3: Information disclosure already requires this. Our 2021 submission[3] to the Authority discussed our views on non-network solutions. That submission included a section from our 2021 Asset Management Plan describing our major projects and the solutions considered (network and non-network). From a bang-for-buck perspective, a review of this information could focus on the *x*-highest value projects for each distributor.

Another option is for to leverage the "project overview" format that Powerco produced for major projects as part of supporting information for the 2017 CPP proposal[4]. The first page is shown below:

Powerco CPP – Portfolio Overview Document

Portfolio Name	Inglewood 6.6kV to 11kV conversion
Expenditure Class	Capex
Expenditure Category	Growth & Security
As at Date	12 June 2017

Expenditure Forecast[1,2]	Pre CPP	FY19	FY20	FY21	FY22	FY23	Post CPP	CPP Period Total	Project Total
Pre-Internal Cost Capitalisation and Efficiency Adjustments[3] *(2016 Constant NZ$(M))*	$0.0	$2.1	$2.7	$0.7	$0.0	$0.0	$0.0	$5.5	$5.5
Post-Internal Cost Capitalisation and Efficiency Adjustments *(2016 Constant NZ$(M))*	$0.0	$2.3	$2.9	$0.8	$0.0	$0.0	$0.0	$5.9	$5.9

Description	
Project need overview	Inglewood substation operates at 6.6kV. This lower distribution voltage results in compatibility issues with the surrounding area and the distribution transformers are not standard items on Powerco's network. Voltage at the end of some of the distribution feeders is below acceptable limits. The substation itself is loaded beyond firm capacity and backup from surrounding areas is limited due to the variation in distribution voltage.

Preferred Solution	
Project solution Overview	The proposed solution is to convert Inglewood substation to 11kV. This involves replacing the remaining 6.6kV/415V distribution transformers with dual ratio units then converting everything to 11kV.

Need Identification

[1] Forecast expenditure is based on Powerco's financial year (i.e. FY18 is for the period April 2017 through March 2018). Expenditures do not consider general price level changes over time (i.e. are in real or constant terms).
[2] Only includes Growth & Security Expenditure. Some projects discuss and rely on the replacement of assets that are at "end of life". However, the replacement cost for these assets is accounted for in the Replacement Expenditure category.
[3] All other forecast expenditure / cost estimates in this POD are pre-internal cost capitalisation and efficiency adjustments, consistent with this forecast.

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Page 4 of the PoD illustrates a range of criteria that could be used and how options can be assessed, including doing nothing.

[3] https://www.powerco.co.nz/-/media/project/powerco/powerco-documents/who-we-are---pricing-and-disclosures/submissions/2021/electricity-authority---edb-regulatory-settings.pdf

[4] https://comcom.govt.nz/regulated-industries/electricity-lines/projects/powercos-20182023-cpp?target=documents&root=61551

Long List of Options | High Level Assessment										
Inglewood 6.6kV to 11kV		*Long list of projects and high level assessment*	*Assessment Criteria*							
PROJECT FOCUS	**No.**	**PROJECT**	Fit	Feasible	Practical	GEIP	Security	Cost	**Short-list**
Do Nothing	1	Allow the electrical demand & risk of consumer non-supply to increase	✖	✔	✔	✖	✖	✔	✖
Non-network:	2	Distributed Generation (DG) including peak lopping generation	✖	✔	✖	✔	✔	✖	✖
	3	Fuel switching to reduce electrical demand	✖	✖	✖	✔	✔	✖	✖
	4	Demand Side Response (DSR)	✖	✖	✖	✔	✔	✖	✖
Network Reinforcement	5	Maintain the network at 6.6kV (reconductor and voltage regulators)	✔	✔	✔	✖	✔	✔	✔
	6	Convert to 11kV over CPP period using step up transformers	✔	✔	✔	✔	✔	✔	✔
	7	Convert to 11kV over a 3 year period	✔	✔	✔	✔	✔	✔	✔

Key:

Fit	Fit for Purpose: Does the option address the need appropriately and does it fit with other developments in the vicinity.
Feasible	Technically Feasible: Consider the complexity, future adaptability, and whether it aligns with company standards, strategies and policies.
Practicality	Practical to Implement: Are there potential environmental or property issues which may be insurmountable. Can it be achieved in the required time frame.
GEIP	Good Electricity Industry Practice (GEIP): Good practice (technically and environmentally) and in terms of AM practice (capacity, age, technological, safety)
Security	Security and Reliability: Does the option provide adequate levels of security and appropriate reliability considering the demand, load type and future growth.
Cost	Some options will intuitively be known to be far more expensive than other options, and this may preclude them.

This project is in the final phase, as discussed here https://www.powerco.co.nz/what-we-do/our-projects/inglewood-upgrade.

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?

Issue 2 focusses on distributors favouring in-house non-network solutions. The Authority's preferred solution is to "encourage distributors to make 'standing offers' for DER" (option 3) and to "monitor distributors' use of competitive procurement" (option 4).

We support option 4 over option 3, given the latter is a single example of the former and there are other options that could be more effective at matching the service needed and provided to genuinely reduce long-term network costs. For example, the link between "avoided cost of transmission" (now removed) and transmission investment is worth considering because as a form of standing offer that was assessed to have made no difference to transmission investment. Linking a signal to the decision outcome is vital, especially if investments make forward assumptions about it. In addition to network benefit, there is also a case for being apportioned a share of network cost as in the Transmission Pricing Methodology. For many new investments, a benefit-based approach will be used for allocating cost recovery and includes both generation and consumers paying a share of charges. In theory, the same logic applies to distribution networks: the network provides a benefit to those exporting.

One way forward could be to explore a time-limited funded trial that would address economic and market regulation and incentives along with measuring effectiveness. We are also interested in the Authority's views about the applicability of this concept to Transpower as an alternative to network investment.

In terms of addressing the issue raised in Q32, the related party requirements on distributors are audited and transparent. They are the natural starting point for assessing any concerns about cost, cost allocation and competitive procurement.

Q33. Do you think there are circumstances in which the Authority should extend the arm's length rules? If not, why not?

We are interested to see submitted responses (and/or Authority views) framed as "If yes, why yes?".

Distributors should be able to deliver the network service with as few constraints as possible to meet lowest cost – this would mean not being prohibited from owning or operating a particular type of solution like DER. New technologies may well be able to provide the most effective solution and best integrated with network operations. So a better approach is that there are measures in place to ensure that a fair and transparent process is adopted when sourcing (DER) solutions. This approach can deliver the best of all worlds: competition, efficiency, and reliability.

Q34. Do you agree with the Authority that Option 1 should be implemented, and that Option 2 could 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?

With the scale of NNS low at present, this section of the report understandably considers possibilities, and in 5.109, the Authority does not consider this a serious issue at present. The options for issues 1 and 2 all involve transparency of process, cost, and solutions which seems to address much of issue 3. As the Authority notes in 5.102, Part 2 of the Commerce Act applies should the Authority's concerns expressed in 5.105 ("engage in exclusionary strategies") eventuate.

If any action is required, the Authority's preferred option to monitor information disclosure data (option 1) should be low cost. Powerco's views on arms-length rules are the same as presented to the Select Committee[5] in 2021. Rules limiting distributor involvement in contestable activities have always been a matter of primary legislation with wide-reaching consequences for market function:

- Regulatory certainty is important to facilitate investment
- Restraining a market participant from participating in a service, or owning assets, is a significant policy choice.

Although these powers are in the Code, their importance remains, particularly in an environment when infrastructure will have a key role supporting Aotearoa's electrification needs efficiently and securely.

We support rules that ensure non-discriminatory access to networks and efficient procurement decisions by distributors. Simply extending the corporate separation/arm's-length requirements of Part 3 to other contestable activities would undermine the potential benefits of new technology by:

- Limiting our ability to undertake research and development to understand the impact of new technology on our network
- Undermining initiatives to provide more reliable, flexible and low-cost supply, particularly to remote and rural communities
- Preventing us from building and operating assets ourselves in parts of the country that other suppliers are currently unable or unwilling to service.

We requested the legislation include guidance to the Authority beyond the general empowering provision in s32 of the Act. The current state is that the Authority has the power to make rules that determine the structure of the industry and what activities participants are permitted to engage in. This has significant policy implications, though there is no clarity to guide the Authority about the intended boundaries of that rule-making power, the purposes for which the power can be exercised, or the considerations the Authority should take into account.

Capacity and capability

The Authority's impression is that this is a minor issue (para 6.20) and we have no additional evidence to suggest otherwise.

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?

We encourage the Authority to engage directly with the ENA on any identified opportunities in this space.

[5] https://www.powerco.co.nz/-/media/project/powerco/powerco-documents/who-we-are---pricing-and-disclosures/submissions/2021/submission-to-select-committee-on-electricity-industry-amendment-bill.pdf

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 DERs and their procurement of NNS projects? And should this be combined with the first option?

As above, we support the Authority (or any party) that spots opportunities to support consideration of NNS, and procurement where they are efficient, engaging directly with the ENA.

Operating agreements for flexibility services

The Authority considers that there is no issue to address now (para 7.36). We agree and support the Authority putting resource towards other topics. Operating agreements are an important part, but just a part, of what is required to operate a non-network solution. A better place to focus resource is the planning, assessment, and capability of NNSs, which is the subject of the 'equal access' part of this consultation. We and other EDBs have shared our operating agreement templates, along with supporting information, with industry. This information is now public and collated across all EDBs on the ENA website https://www.ena.org.nz/resources/edb-requests-for-non-network-alternative-services/.

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?

Given operating agreements are public, we are confident that the core terms can be replicated and tailored easily (efficiently).

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?

A better focus is on the development of NNS given operating agreements are one of many parts supporting implementation. Given these agreements are an enabler of an NNS, all parties will have incentives to discuss regulatory barriers or risks with the Authority (and any regulator), and look at solutions.

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?

An area of potential support could be if the agreements touch on compliance or liability issues.

DER standards

Q40. What are your thoughts on the proposed scope for the Part 6 review? What, if anything, would you include or exclude, and why?

We agree that a review of Part 6 is required because of the significant increase in volume and scale of applications to connect distributed generation. We would like to see pricing included within the scope of the Part 6 review. Limiting charges for distributed generation to incremental cost gives rise to a number of issues, such as:

- Existing consumers may subsidise distributed generation where a distributed generator does not pay a share of fully allocated network costs
- Distributors may be unable to recover the costs of anticipatory capacity from subsequent connecting distributed generators
- The different approach to recovering transmission vs distribution connection costs may influence investment decisions and the location of distributed generation based on whether to connect to the grid or distribution network.

Confidentiality of certain application data could be reviewed to allow meaningful data to be published at an aggregated level eg GXP or substation.

Q41. In order, what are the three most important issues that should be addressed as part of a Part 6 review, and why?

What	It's important because…
Large DG connection process (including prioritisation)	• There are many affected parties • Part 6 is not suitable for large scale DG applications that often involve land sale or leases, significant network upgrades, transmission works, project consenting, third party financiers etc, none of which are sufficiently provided for in the current part 2 connection application process • More certainty and consistency will ensure developers can make efficient assessments and decisions with their capital resource • Distributors can better allocate limited resources e.g., based on an assessment of project readiness • High developer interest puts a premium on attempts to secure network capacity. Days can matter. If the priority of applications is better managed we will have a more sustainable process for all parties. There is a direct link to the pricing principles given the impact of those on network requirements applications
Power quality standards	• There are a lot of customers affected • Various power quality issues arise from the high penetration of DG to the distribution network affecting many customers (not only the distributed generator)
Fees	• The fees are mismatched with the costs incurred by EDBs and it can influence the application process dynamics

Q42. What are your thoughts on amending Part 6 of the Code to explicitly include DER, and what do you think are the key issues to be considered?

We support this, though are keen to see other views. Issues to consider include

- Potential services/functions from DER eg VAR support and responding to network events
- New technologies which can perform multiple functions eg Vehicle to Home (V2H) and Vehicle to Grid (V2Grid). It might not be an issue right now as the technology is still new to NZ, but it may get to scale in the near future.

Q43. What are your thoughts on increasing the size threshold for Part 1 DG applications, including the benefits and drawbacks?

The current lack of LV visibility combined with relatively short time frames could combine to create some network supply issues. In rural areas we have a lot of small transformers eg 15kVA that supply multiple installations. As load connections, that can work due to the diversity effects. If the threshold is lifted to include installations that result in export, there is a greater likelihood of less export diversity. If there are multiple large DG installations on a small transformer there could be overloads or blown transformer fuse problems. Expanding the threshold will exacerbate this risk. Evolving the network smarts to facilitate these scenarios creates costs and is one reason why distribution pricing will likely need to include prices for export and/or other network impacts.

Q44. If the threshold were to change, what do you think the new threshold should be and why?

If it were to be changed, 30kW is a pragmatic boundary between residential and commercial applications. Consider bundling with a mandated AS/NZS 4777.2.2020 standard.

Q45. What are your thoughts on adjusting the ten-business day timeframe in Part 1A?

We are comfortable with the 10-business day turnaround time for DG applications that are under 10 kW, though we are interested in views from other parties about whether it could be longer eg target 10 business days, max 20 business days. We are meeting the current turnaround time because most areas have hosting capacity available, we are not undertaking engineering modelling studies, and we use the Australian Clean Energy Council website to check the compliance of the inverters to AS/NZS 4777.2.2020. It is likely one or all of these will change, which will put pressure on the cost and/or time to process applications.

We do see merit in an extension option (similar to Part 1 and 2) to account for delays due to circumstances such as the scale or complexity of assessment, or safety. A key factor in our ability to meet deadlines for Part 1A applications is the volume. If DG installers batch-process applications it can lead to high peak volumes, and that will only get worse as the number of installations continues to climb. There is a link to resourcing requirements and the Part 6 fee schedule.

Q46. What are your thoughts on maintaining the current approval timeframes in Part 1 (comprehensive) and Part 2?

Agree.

Q47. If you seek a change to approval timeframes, what evidence can you give to support this?

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.

Agree.

One option would be to have no prescribed application process to connect large-scale DG. EDBs could develop their own processes (like Transpower). While this would provide maximum flexibility, we envisage this would be unappealing for developers of largescale DG (who would have to navigate different application processes across networks), and potentially some EDBs who don't have the capacity to prescribe and manage their own process. As such, we think the question is "how, not if" the connection process for large-scale DG should be dealt with in Part 6.

As noted by the EA in 8.48, there are unique technical challenges which are more similar than different to what Transpower has to consider when connecting generation. EDBs are required to undertake technical studies to determine the impact of the connection at the GXP, to meet contractual obligations to Transpower, and most importantly, ensure we can maintain power quality to other customers, and meet safety requirements for customers, technicians, and the public. Project readiness, consenting, land rights and significant network investment are also important considerations.

Some topics to consider in a new application process for large scale DG include:

- Considering whether Transpower's new process is a useful precedent/example
- Core technical principles that prospective generators need to meet in being connected
- The timing of final applications and technical studies
- A staged approach with milestones to proceed to the next stage, including matters such as land ownership, consenting, project finance, build contracts, quality of information supplied
- Potentially a bond to secure priority

- Ensuring the new process is appropriate to different types of DG e.g., consider whether milestones that are appropriate for wind are also appropriate for solar
- Transparency around network constraints and potentially the ability to make connection applications public at an early stage to enable other applicants to factor them in.

Q49. If you think a new application process should be added, where should the threshold be and why?

The 1 MW threshold is significant because it marks the point at which DG information must be provided to the System Operator. At this threshold, the injection of DG into the network could significantly impact power quality, particularly in weaker parts of the network. Additionally, 1 MW may also be the threshold at which DG could potentially have an impact at the GXP and where network alteration upstream of the point of connection to the network is required.

Q50. What are your thoughts on reviewing the priority of applications clause in Part 6 of the Code?

We support a review to consider whether some form of priority should reasonably and appropriately be afforded to initial applications, particularly because the 'race' to get final approval to secure capacity creates several issues for EDBs.

We also support some action in relation to final applications, which is that considering the Part 6 purpose when assessing competing applications can be difficult to apply. Some options to remedy this include

- Amend the purpose of Part 6 to provide more clarity about the desired outcome in the context of competitive bids
- Amend Part 6 to include a purpose applicable when considering competitive bids
- Amend Part 6 to specify the criteria on how competing final applications are assessed.

Our preference is for one of the first two options, with a preference for the second as it would provide clarity, flexibility, and be targeted at the specific issue.

Q51. Should the AS/NZS 4777.2:2020 Standard be mandated for inverters in New Zealand? If so, how should this be accomplished?

Yes, to deliver the benefits outlines in para 8.68.

Another consideration is how inverter replacement is handled. If an existing inverter is to be replaced with a new one of the same size it would not require a DG application. However, the Code or other regulation must make clear that it must meet any applicable standards eg AS/NZS 4777.2.2020. A common source of PQ issues such as harmonics, is the widespread use of cheap power electronics. We could introduce power quality issues to the network if we don't standardise a certain compliance level.

Q52. What are your thoughts on the Authority reviewing the prescribed maximum fees in Part 6 of the Code?

Agree.

This needs to include the scope of any fees eg the application fee is a processing/admin fee with technical effort and review costs being additional and to be agreed between the parties.