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Electricity Authority
Wellington
By E- Mail: distribution.feedback@ea.govt.nz

Re: Issues Paper—Updating the Regulatory Settings for Distribution Networks

Counties Energy Limited's commends the Electricity Authority (Authority) on the "Issues Paper—Updating the Regulatory Settings for Distribution Networks" (Paper) being well written, timely and covering a range of critical EDB regulatory constraints.

Where the Paper could be improved is in better understanding the likely impact of decarbonisation on distribution networks and the practicalities of EDBs developing new systems to manage this impact. Without this core understanding, the benefits are likely overstated, the regulations not fit-for-purpose and there is no allowance for the time and investments needed by EDBs to develop the necessary systems and capabilities. From Counties Energy's experience[1] developing real-time ICP data systems takes a significant investment and time, but there are significant benefits with Counties Energy winning an Energy Award in 2019 for the work undertaken[2]. There are also unexpected benefits such as Counties Energy using smart meter data to identify potentially dangerous faulty neutrals within customer premises, with this work winning the Electricity Engineers Association Public Safety Award in 2021[3].

Impact of decarbonisation on distribution networks

There is benefit in better understanding how decarbonisation will impact distribution networks because this will help inform the Authority on the likelihood of the proposed Code changes being practicable. As figure 1 in the Paper illustrates, the two main drivers of electricity demand from decarbonisation will come from vehicle electrification and process heat. What is missing in the Paper is the very different impact on distribution networks that occurs from these two decarbonisation demand drivers.

Nearly all the decarbonisation of process heat will occur on less than 1% of EDB ICPs, with this demand coming from a few industrial customers[4]. These customers already have high voltage connections, and EDBs have processes to manage increased capacity to their sites, as well as many industrial heating processes having decarbonisation biomaterial alternatives to electricity. Electrification of transport will have a very different impact on distribution networks because there will be widespread EV charging across distribution

[1] Nearly ten years of detailed real-time and half-hourly data ICP data, experience in supplying industrial and mass market customers, a microgrid trial, installation of major distributed generation and commenced the development of a Distribution System Operator (DSO).

[2] https://www.energyawards.co.nz/content/counties-power-putting-smarts

[3] https://www.eea.co.nz/Site/awards-new/workplace-and-public-safety-awards-new/public-safety.aspx

[4] Residential natural gas is only 1% of New Zealand's total energy demand and commercial buildings a further 1%. Nearly all the process heat is being used by industrial customers and there are very few industrial customers on EDB networks.

networks with transport fuel having no viable alternative to electricity. Furthermore, transport is New Zealand's biggest energy demand[5], so decarbonising transport requires a greater amount of electricity that is spread over a large number of ICPs.

Consequently, the biggest impact on distributor networks of decarbonisation will be from the electrification of transport. This impact will be compounded by New Zealand's high car ownership and the increasing charging speeds of residential wall mounted EV chargers. If the Authority, and Government, ensured regulations to manage EV charger installations, such as regulating that EDBs must be able to control EV chargers for network emergencies and EV charger standards, EV charger demand could be managed and with increased distribution network utilisation and reduced peak thermal generation.

Counties Energy's EV charger distribution modelling has found that its standard low voltage network is impacted when there is one in seven homes using a wall mounted 7kW EV charger. With an average two cars per house, and long-term likely nearly all cars to be electric, the impact on distribution networks from EV chargers will be significant. Furthermore, DER solutions such as solar and batteries will be ineffective at managing the EV charging demand because it is not cost effective to install solar and batteries across the entire low voltage distribution network.

Non-network solutions (NNS) involving solar and battery solutions are also likely to have minimal benefit for industrial process heat decarbonisation because industrial demand is normally base loaded and battery/solar solutions can only provide limited periods of supply. Where solar and battery solutions will likely be effective is in deferring major high voltage distribution network infrastructure that is the result of ICP growth. However, NNS opportunities are rarely required and therefore the benefits are not substantial, and the Authority and Government should focus on EV charger regulations.

Complexity of determining distribution capacity

The Paper could benefit by seeking a better understanding of distribution network capacity, network congestion[6] and voltage. Distribution networks capacity has traditionally been designed for a one-way transmission of power from a Transpower substation to the customer. For the high voltage network the limiting capacity is nearly always the thermal equipment capacity but from the 11kV/400V transformer to the customer the low voltage capacity is often limited by the voltage drop. Distributed generators exporting power in the opposite direction is not what the distributed network was designed for, and in Counties Energy's experience the distribution capacity is significantly lower on the same network asset because of voltage rise.

Consequently, there is a different network capacity for customer demand as compared to DER exports. Furthermore, the available export capacity will change over time depending on electricity demand (similarly, available ICP import capacity depends on DG exports at the time). For EDBs calculating the thermal capacity is relatively easy but calculating the voltage capacity is complex. Therefore, determining available capacity requires more than just half hour data and maximising the utilisation of the network (i.e. maximising the export from DG and available import) will require real-time data.

Counties Energy believes that 5-minute real time voltage data will be critical for DER management. This is because voltage changes will provide signalling as to the available distribution asset capacity.

[5] In 2021 fuel was 50% (272.33PJ) of New Zealand's total energy demand and electricity 26%. For more detail see www.mbie.govt.nz/building-and-energy/energy-and-natural-resources/energy-statistics-and-modelling/energy-statistics/energy-balances/ .

[6] Distribution networks can't operate a congested network because this would lower (or increase if constrained from exports) voltage below regulated levels and damage customer equipment.

Distribution System Operator (DSO)

New Distribution System Operator (DSO) functionality will be required by EDBs to manage flexibility traders and maximise the utilisation of distribution networks. This would be through ensuring flexibility traders bid or contract services that the DSO dispatches in real-time to maintain customer power quality (e.g. voltage drop) while maximising utilisation of distribution assets. This is how EDBs will utilise NNS solutions to defer network investments. To this end, Counties Energy has commenced work on quantifying the commercial benefits of investing into a DSO, with the associated costs being offset through the deferment of network investments[7]. The next step will be to undertake a DSO trial.

Questions and answers

No.	Question	Answer
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?	Given that the UK's electricity market is different to New Zealand's market one review would be sufficient. There are a number of key differences including: • Unlike the UK, New Zealand is not seeing a significant investment in solar arrays, which reflects the difference in Government subsidies; • The nature of the UK housing market means that there is likely to be far less home EV charging; and • UK distribution networks are likely to face decarbonisation issues associated with the UK's high reliance on reticulated gas for home space and water heating.
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?	Counties Energy believes that 5 minute near real-time data is required for DER management of network constraints. Critical would be 5 minute voltage data, as EDBs need to manage to the regulated voltage. Without maintaining voltage customers electrical equipment will stop functioning correctly and could be damaged. There is likely to be other data requirements in the future as EDBs start to manage DER and learn from overseas experience. These requirements will be far in excess of the half-hour kWh data requirements from retailers.
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?	The pace of technology change is greater than the pace of regulatory change. Consequently, the proposed changes will likely be too little too late. The Authority should consider the contractual MEP/retailer/EDB arrangements because EDB data requirements will be greater than the retailer requirements.
Q4	Does this capture the key data needs for flexibility traders to make informed business decisions that will unlock the potential of DER	The proposal by the Authority of calculating real-time low voltage (LV) congestion seems impractical and probably unfeasible. It is impractical because it is very difficult to calculate congestion on all EDB LV assets and it would change constantly depending on customers behaviour and

[7] There are a number of added complications including how deferred capital cost savings are shared with the DER flexibility provider who will then pass the benefits on to the end consumer.

	for the long-term benefit of consumers? If not, what is missing and what would the data be used for?	connected equipment. For instance, as customer demand increases then there is increased network capacity for distributed generation (DG) exports.
Q5	Do you agree with the prioritisation of the key data needs for flexibility traders? If not, why not?	Counties Energy disagrees with the proposed approach to how flexibility traders would operate. This is because there will be numerous flexibility traders and a co-ordinated approach is required with the co-ordination being led by the EDB's DSO. Under this approach the EDB will send a signal to the flexibility traders to drop load or inject power (e.g. discharge a battery). This would not require the flexibility trader needing real time congestion data.
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?	The Data Template structure is the incorrect regulatory process, and a more fundamental change is required as EDB ICP data requirements should be the primary future metering driver. The retailer requirement for half hourly demand data is a minor requirement moving forward.
Q8	Do you agree that this is an issue? If not, why not?	Yes, MEPs should contract directly with distributors and flexibility traders for the direct supply of data. There is also a need to ensure that MEPs install meters that capture more than just half hour data every 24 hours. The amendment to the Code should include metering standards to ensure new meters are able to provide near real time data.
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?	Yes, the Code should be amended because this would overrule any existing MEP/retailer contracts that may prevent the MEP from providing data to an EDB.
Q10	Should the DDA Data Template be updated to include Power Quality Data? If not, why not?	Counties Energy believes that power quality is as important for DER management as consumption data. This is because DER management is about maintaining voltage and there should be no privacy issues around providing voltage data as this is related to the distribution network.
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?	It takes considerable time, and investment, to effectively utilise additional DER data and integrate the new systems into EDBs existing IT systems and processes. It would be unrealistic to expect that EDBs will be able to utilise the data as soon as it is provided so if the DER need is in three years, then the data needs to be available now.
Q16	Do you have any views on the type and size of DER that needs more visibility?	Dedicated EV chargers 7kW or greater in business and residential premises should require EDB approval before being installed.

Q17	The Authority acknowledges that definitions of 'real-time' vary, please explain what real-time data means to you.	Real-time data would be within 60 seconds of the event and near real-time data between 60 seconds and 5 minutes.
Q18	Do you agree that access to 'real-time' consumption and Power Quality Data won't be needed for at least five years?	It takes years to develop the necessary systems and platforms to be able to use the data. Consequently, if the data is required in five years' time, then EDBs should have access to this now to enable them to commence negotiations with MEPs to obtain the data and then develop the systems to handle and utilie the data.
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?	As there will be multiple flexibility traders on an EDB network, it is unclear how the flexibility traders will have visibility over their competitors? Counties Energy expects that the DSO, separate from the distributor, would orchestrate the flexibility traders to ensure the greatest utilisation of distributor assets, while maintaining regulated voltage 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 likely that future DSO management of LV networks will require a minimum 5 minute near-real time voltage data. It may be better to see how the market for flexibility traders develops before determining how best to provide data to all the concerned parties.
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 do not need granular current and future Congestion Data. Distribution constraints need to be managed by a DSO. How would a flexibility trader react to a distribution constraint when there are multiple flexibility traders all participating in real time to manage a constraint on the same distribution infrastructure?
Q22	Are there any other issues preventing distributors from providing granular current and likely future congestion data?	Yes, "congestion" will occur at the LV level and will need to be managed by the DSO in real-time (or near real-time) using voltage data. At the LV level it will not be possible to calculate "congestion", but instead manage distribution constraints through managing voltage (i.e. the voltage will increase for an export constraint and drop for a demand constraint and the DSO would need to manage this fluctuation).

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?	No, the congestion will occur at the LV level and Counties Energy is already having rural PV voltage issues from rural residential PV connections. Furthermore, it is unclear what the Authority means by 'larger DER', but it is likely that most EDBs already have this visibility through their SCADA systems.
Q24	Do you have any views on the type and size of DER that flexibility needs to have improved visibility?	Visibility is required for all dedicated EV chargers and batteries.
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?	Yes, it would improve visibility for DER to be recorded on to the ICP registry database. This should also include dedicated EV chargers.
Q26	Do you agree that the Authority should prioritise work on addressing the other issues outlined in this paper?	Requiring visibility of dedicated EV chargers is critical because this will have the biggest impact on EDB networks.
Q27	Do you agree that flexibility trader access to real-time congestion and ICP data won't be needed for at least five years?	It will take a long-time for flexibility traders and EDBs to develop the systems to utilise the real-time data. Consequently, the data is required today if the Authority expects EDBs to be able to manage the impact of DER and decarbonisation in five years away using real-time data.
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?	The largest future NNS will be from being able to manage EV charging loads. Currently at network peak times the co-incidental household peak demand is around 2.6kW, which will significantly increase with most EV wall chargers being 7kW with around an average of two cars per home. This scale of increased peak demand will necessitate EDBs to manage EV charger demand or significantly investment in new network capacity. EV charger ownership and peak demand management could be similar to residential hot water cylinder ownership and demand management. EDBs don't own, install or supply the hot water cylinder, but instead provide discounted line charges to those customers that want to save money on their power bill by having their hot water power supply managed. Similarly, EDBs don't need to own home EV chargers and instead provide a financial incentive

		to those customers that want to have their EV charger load managed. The discussion on NNS in the Paper appears to be around battery solutions as alternative to network investments. As is evident with the battery/solar NNS to date, these are likely to be alternatives to large scale high voltage (HV) investments such as a distribution substation or a feeder upgrade. This solution works at the high voltage level because it requires only a limited percentage of customers to install a battery/solar solution option to cumulatively have a high impact at the HV level.
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?	Yes, the Authority should encourage EDBs to make standing offers for DER where the benefits are widespread. This would be similar to the benefits offered by EDBs through customers having lower controlled line charges. Yes, also to option 4, where a competitive procurement would be separate and be offered for flexibility traders for a certain area as an alternative to a major network investment.
Q33	Do you think there are circumstances in which the Authority should extend the arm's length rules? If not, why not?	The Authority should differentiate between NNS behind the meter from NNS that are within the distribution network. In particular, the Authority should definitely not extend arms-length rules for grid scale batteries that sit within a distribution high voltage network. If the Authority were to put arms-length rules on equipment within the distribution network, then it would be similar to having external companies own EDB transformers. If the Authority did put arms-rules on EDBs owning NNS within the distribution network (e.g. grid scale batteries), then this would slow the uptake of the technology because there would be health and safety risks to the EDB for external parties to be within substations or the external party would need to have a high voltage connection and metering to the distribution network. The Authority should also not prohibit EDBs from requiring direct control of home EV chargers for network and grid emergencies. The alternative would be increased risk of customer outages to balance load during peak demand periods or when there is insufficient generation to cover demand.
Q34	Do you agree with the Authority that Option 1 should be implemented, and	Option 1 should only be implemented with respect to DER assets behind the meter. DER assets within the distribution

	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?	network should be considered an extension of existing HV assets. In addition, the Authority needs to quantify the potential for competitive harm because future DER load is likely to be dominated by residential EV chargers a market that is highly competitive. Furthermore, EV owners are likely to consider a minor benefit any DER flexibility offered by the EV charger seller. This is especially true when electricity retailers are offering hours of free power, which is allowing free EV charging for EV owners. In comparison, the rebate, or line charge savings, that an EDB is able to offer a household with an EV charger (via a flexibility trader) is likely be of significantly less value.
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 Authority should ensure that regulations exist to enable EDBs to collaborate especially in the enabling of DSOs. Future DSOs will have strong economies of scale so that one DSO could provide services to multiple EDBs.
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?	Yes, the Authority should encourage joint ventures for integration of DERs. In particular, the integration of DERs requires EDBs to make significant cost and time investments into new DSO platforms that will have significant economies of scale.
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?	Flexibility traders will be able to earn revenue from a number of sources including offering it to electricity retailers during high spot price periods and bidding into the SIR/FIR markets. These markets may offer a better return than can be provided by an EDB. However, the Authority should regulate to ensure that the DER is available to EDBs for distribution and transmission emergencies.
Q38	Do you have any views on the best way the Authority can monitor whether issues	Given that the market for flexibility services is only beginning to form it is too early for the Authority to mandate terms or a template. In fact, the nature of these

	associated with operating agreements for flexibility services are developing?	flexibility services may be different to what the Authority expects. For instance, Counties Energy already contracts with a major customer for line services that includes demand flexibility in fault situations. EDBs need the flexibility to negotiate customised terms that benefit both the customer and the EDB.
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?	The Authority could facilitate workshops between DER providers (e.g. EV charger suppliers, microgrid owners and battery/solar providers) and EDBs to seek alignment on how flexibility services could operate in the future.
Q40	What are your thoughts on the proposed scope for the Part 6 review? What, if anything, would you include or exclude, and why?	Part 6 needs to be reviewed and updated. This review should also include the following: • Part 6 pricing principles, with the requirement for incremental cost recovery only needing to be rescinded. This requirement is already limiting DER uptake on Counties Energy's network because whole feeders are becoming congested. If standard pricing principles was allowed, then the revenue to upgrade the congested feeders could be obtained through spreading the costs across all DG customers. • The review needs to include the period of time that the DG application approval is valid for because most DG applications above 1MW need to obtain resource consent and funding once they are approved to connect to an EDB network. This means that the approval needs to be in place at least 3 years.
Q41	In order, what are the three most important issues that should be addressed as part of a Part 6 review, and why?	1. There is an urgent requirement for all DER to be included into Part 6. This includes batteries and wall mounted EV chargers. 2. The incremental cost rule limiting DG line prices needs to be reviewed as a matter of urgency. 3. The period of time that there is capacity reservation, which is required to enable DG applicants to obtain resource consent and funding.
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?	DER should be included into Part 6 including batteries and wall mounted EV chargers. EV chargers need to be included because of their ability to export power back into the grid from an EV.
Q43	What are your thoughts on increasing the size threshold for Part 1 DG applications, including the benefits and drawbacks?	The threshold should remain at 10kW because this covers most residential solar applications.
Q44	If the threshold were to change, what do you think	New thresholds should be included as the work required from larger DG connections is significantly more that say a

	the new threshold should be and why?	DG connection to around 400kW. The following DG thresholds are proposed: DG<10kW DG >10kW and <400kW DG 400kW and <1MW DG >1MW and < 5MW DG >5MW
Q45	What are your thoughts on adjusting the ten-business day timeframe in Part 1A?	With rural DG less than 10kW creating voltage issues on Counties Energy's network, all DG applications are now being investigated carefully to ensure they do not result in voltage issues for other customers. Given the engineering analysis required, the ten-business day timeframe is far too short, and a more realistic timeframe would be 30 business days.
Q46	What are your thoughts on maintaining the current approval timeframes in Part 1 (comprehensive) and Part 2?	Counties Energy has DG applications to connect generation significantly greater than the available network capacity, who are then proposing alternative options for sub-transmission line upgrades. Evaluating these options is complex and taking months to evaluate with external consultants being required. Consequently, the timeframes for DG above 1MW needs to be three times longer.
Q47	If you seek a change to approval timeframes, what evidence can you give to support this?	As more DG is added to distribution networks the impact of voltage rise will require increased careful analysis. This includes load flow studies that take into account both network infrastructure capacity and minimum demand.
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.	Yes, greater than 1MW requires detailed network studies including the costing analysis to reinforce feeders. Greater than 5MW may require DG applicants to consider the requirement for them to obtain an easement across farmland for a new high voltage distribution feeder or transmission line. Plus there are also considerations around the available capacity given existing DG connections.
Q49	If you think a new application process should be added, where should the threshold be and why?	The most critical would be a 1MW threshold, but ideally a new 400kW application process would also be added. The 1MW limit is because above this size there are normally high voltage distribution feeder constraints. In regard to 400kW, this is required as otherwise there would be a significant jump from 10kW to 1MW.
Q50	What are your thoughts on reviewing the priority of applications clause in Part 6 of the Code?	There needs to be an application priority, queuing and capacity reservation as Counties Energy is now seeing multiple applications for the same distribution feeder, which has only limited capacity.

Q51	Should the AS/NZS 4777.2:2020 Standard be mandated for inverters in New Zealand? If so, how should this be accomplished?	Yes, new standards should be adopted as a matter of urgency. In addition, Part 6 should also permit EDBs to require DG owners to update their inverter after 10 years or earlier if there are safety concerns. In particular. inverters can start to fail to turn off in faults risking the PV to start exporting on to a network fault as it is being repaired.
Q52	What are your thoughts on the Authority reviewing the prescribed maximum fees in Part 6 of the Code?	The maximum fees need to be adjusted significantly as they have not been adjusted for inflation and the increasing complexity of adding DG on to EDB networks.

Counties Energy would be happy to discuss any aspect of this submission.

Yours sincerely

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