Northpower

Updating the Regulatory Settings for Distribution Networks

March 2023

Overview

Northpower welcomes the opportunity to provide feedback on the Electricity Authority's issues paper on Updating the Regulatory Settings for Distribution Networks.

Core Messages

Network Visibility

We support the Authority's overall direction to make energy sector data publicly available, and ensure two-way communication between retailers, MEPs, EDBs, and flexibility providers. We see this as an important enabling step to optimise networks, and optimise energy markets over time.

Historically, distribution networks were generally one-way and power flows were relatively predictable, meaning that networks could be constructed and operated on a 'set and forget' basis. This contrasts with Transpower, which operates a two-way system, and as a result has real-time communication at the point of connection for each of its customers. Clearly EDBs and energy markets will need to make this step over time.

Increases in DER penetration are now triggering pockets of distributions to utilise real time distribution system operation, and increasing parts of distribution networks will be subject to this requirement over time. EDBs currently do not have the data we need to fulfil this role despite much of that data set being available via point of connection data. Improvements in customer experience in terms of faults identification and restoration are also possible through leveraging point of connection data.

We consider it likely that the optimum long-term solution would be a central repository of consumption and power quality data, which could be accessed by all market participants as required, with appropriate privacy controls in place. In the short to medium term, we support the Authority's direction to improve the flow of data and increase certainty over contractual terms and prices to access this data. We provide our specific feedback on the proposed mechanisms in our detailed responses below.

Part 6 Review

We support the Authority reviewing Part 6, but think that a much wider scope and stronger focus on long term market enablement is required to make Part 6 fit for purpose. Part 6 wording was adopted from regulations which were drafted in a completely different environment which is now complex and highly competitive. This is leading to sub-optimal market outcomes and unnecessary inertia in enabling DG deployment.

For example:

- incremental cost principles prevent EDBs from acting commercially and instead force them to focus on risk mitigation and minimum service levels.
- incremental cost principles also discourage EDB planning and investment to support DG, including commitment to initiatives such as renewable energy zones. EDBs cannot realistically invest in network assets to encourage future DG connections because there is no ability for an EDB to earn a return on that investment. It is not realistic to expect consumers to effectively fund, at cost, and take project risk in assets that would benefit DG.

- Application processes are focused on an approve/decline outcome, rather than providing the collaborative process sought by DG applicants. Application fees are capped well below actual costs. There is significant ambiguity in relation to application prioritisation and the ability to 'reserve' capacity. The Code does not specifically address to what extent an applicant can amend an application and maintain its priority, and whether an applicant can transfer its application to a third party. Constraint management and prioritisation of multiple connected DG is not adequately anticipated in the Code provisions.

All of the above means that EDBs cannot properly plan for DG on a system basis and instead have to react to individual DG applications.

Broadly, we submit that Part 6 needs a full review for the electricity system to play its role in delivering Aotearoa's zero carbon ambitions, and to unlock the potential economic benefits of DER. We implore the Authority to conduct a full review, beginning with workshopping with industry to identify current issues and design a framework which will deliver these outcomes.

Proportionate regulation

The market for DER will evolve, and while there are a number of no-regrets regulatory actions that can and should be taken, we consider the Authority should avoid pre-emptively regulating while the market is still evolving.

Instead, and consistent with many of the statements made in the Authority's consultation document, the Authority should focus on identifying roadblocks to the evolution of DER and how it can remove these, and accept that it has necessary power to impose regulation where market failings are observed over time. New Zealand has an enviable history of light handed regulation in many parts of the energy system, and this appears to have been successful. EDBs are long term asset managers and understand the need of retaining social licence and regulatory credibility – because of this the sector is geared towards operating in a way that is in the interests of end use customers.

We thank the Authority for its engagement to date on the issues outlined in this paper and look forward to working with you to deliver these improvements which will support improved consumer outcomes and the de-carbonisation of New Zealand.

Specific Questions

Q1: Do you see value in the Authority commissioning two separate reviews to look into the merit and practicalities of implementing the recommendations of the UK's Energy Data Taskforce around unlocking the value of customer actions and assets and setting up a "digital spine" in a New Zealand setting. The Authority will consult on the findings and recommendations of the reviews as appropriate.

We think it is worthwhile for the Authority to understand how DER and the associated regulatory frameworks are evolving in other jurisdictions, and to take learnings from those which can be applied in New Zealand. The UK appear to have applied a considered and methodical approach to modernisation and digitisation of energy markets and in particular changes needed to enable efficient distribution of energy, and so would be a worthwhile region for study.

However, we think there are a number of ‘no-regrets’ actions that can be undertaken now to improve the current regulatory framework and deliver benefits for consumers, and these should not be deferred while the proposed reviews take place.

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

See our response to Q3.

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?

Non-Aggregated ICP level data

We agree that historical non-aggregated ICP level consumption data and power quality data is required, and that this is a priority for the next 1–3 years.

The benefits will include:

- Being able to maximise the capacity we can use in the existing network before investing in upgrades (because when we cannot view actual loads and available capacity, we take a prudent approach and allow for larger contingencies). (**HHR Data**)
- Being able to pinpoint constraint areas and avoid the need to upgrade a larger section of the network. (**Both data types**)
- Identify power quality issues before they start affecting consumers. Reduce outages and potential for property damage as a result. (**Both Data Types**)
- Identify root causes of outages more quickly, reducing fault call out response times and resulting cost. (**Power Quality Data**)
- Improve cost reflective network pricing. For example, HHR data would be required to adjust the start/stop times of our peak/shoulder/off-peak periods. (**HHR Data**)
- Improve safety on our network by improving the ability to identify areas where there are unsafe installations. Having visibility on two-way power flows will also help improve worker safety when carrying out isolations on the network. (**Both Data Types**)

As DG rates pick up it is vital that EDBs are able to augment networks in a targeted and considered way. Without appropriate data, once network limits begin to be reached, reactive investment would invariably lift beyond the levels currently signalled in AMPs due to overly conservative practice.

DER information

We also agree that we need better visibility of DER. Traditionally distribution systems have been one-way systems, making them comparatively simple to manage. The addition of DER changes power consumption patterns (for example evening loads might reduce with the addition of batteries) and changes flow directions (for example exporting solar) making the network more complex to manage.

As the level of DER ramps up, we will need better visibility of the DER installed on the network in order to manage the network effectively, so that we can plan the network appropriately, and so that we can reach out to flexibility traders representing DER resources where they might solve a network issue at a lower cost to traditional solutions.

While we might not need this data in the next three years (depending what the adoption curve of DER looks like), we still think it is a priority because it will be difficult to 'go back' and capture data not captured at the time of install. As such, we think it is important to start capturing this data as soon as possible.

Real Time Data

Distribution networks are currently effectively one way systems, distributing energy from the national grid to consumers. One directional flows have meant that electronic monitoring systems have been able to be minimal, compared to Transpower which has two-way flows and therefore has metering that it can read in real time at every customer connection point.

As distribution networks become two-way systems like Transpower, keeping the system balanced will become a lot more complex, and distributors will need to play a role similar to Transpower's system operator function, to keep supply and demand balanced across the network.

As such, in addition to having visibility of what DER is connected to the network for planning purposes, real-time views will be required to operate the system as the volumes of DER connected to the network increased.

While we agree this functionality is not required urgently (depending on the adoption curve of DER) we are cognisant that DER is being installed now without the capability to provide real-time data back to the network. We think that establishing the processes, standards, and regulations which set out minimum communications capabilities is a priority, so that DER equipment is installed with the right functionality to meet future requirements.

If preparation of the formats and standards is deferred until DER uptake increases, there is a risk that significant DER will have been installed onto networks without the technical capability to communicate with the EDB, and it will be costly or not possible to retrospectively implement.

Q4. Does this capture the key data needs for flexibility traders for them to make informed business decisions that will unlock the potential of DER for the longterm benefit of consumers? If not, what is missing and what would the data be used for?

No comment.

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

No comment.

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?

Combining data

Yes. Our experience in using the Data Template is that some retailers declined to provide permission to merge consumption data for the purpose we stated (which was strictly limited to network related use) under the Data Template, rather requiring that we agree to the ENA/ERANZ version which enables merging of data but imposes other obligations.

In effect, the ability for retailers to decline permission to merge consumption data under the Data Template makes the data template ineffective, because while you can obtain data under the template, you cannot use it unless the retailer agrees.

Other changes

We support:

- Changing the frequency for receiving data from six-monthly to monthly, which will enable much more timely receipt of data.

- MEPs being directed to provide consumption data to distributors by default. We found some retailers preferred to supply data themselves, which caused significant variations in cost compared to MEP direct supplied data. There were also variations in data supplied by MEPs and retailers, primarily around whether the data was ‘raw’ with missing reads or included retailer estimates of the missing reads.

- Clarifying the definition of reasonable costs. We received some quotes which were per ICP, and some quotes which were per data run. We suggest adopting the wording used in the Pricing Principles contained in Part 6 of the Code, which enables recouping of incremental costs which a party would incur acting efficiently.

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?

Data Format

We think it would also be useful if the Data Template stated that HHR data must be supplied in EIEP3 format unless agreed otherwise by the parties.

Best Mechanism

We don’t think that a Data Template between retailers and distributors is the best mechanism for distributors to access data, as the data being sought is held by MEPs and they are not a party to the agreement.

As such, we think that distributors and MEPs should be able to enter into terms for this information to be provided directly to distributors, preferably with default terms as a fall-back option. The Code would need to be modified to allow this, and to also require retailers to include appropriate privacy clauses in their customer agreements to enable the disclosure of this data by MEPs to distributors.

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

We agree that obtaining permission from retailers to access data, and ensuring they have back-to-back agreements with their customers, is an issue.

Broadly, as DER growth occurs and networks change from one-way to two-way flows, networks will need to be able to monitor their network for flows and issues at a much more granular level, in the same way that other networks such as roading, fibre, and cellular already monitor their networks.

There are two ways this could be achieved:

- Distributors could install monitoring devices on its network at each point of connection between a consumer and the network, which would enable it to monitor the power flow and power quality.

- Distributors could be provided access to the data from smart meters, which sit at the end of the customer's service line. Although they are not within the distributor's network, they provide an excellent proxy for the point of connection as they are generally only a few metres away.

The best outcome for consumers is that distributors are provided access to the data from smart meters, because the alternative where distributors install monitoring devices on its network at the point of connection will effectively duplicate infrastructure and inefficiently increase the total cost of delivered energy to consumers.

As such, we consider it critical issues around retailer agreement and privacy are addressed via Code changes, as well as pricing and commercial terms, to avoid inefficient duplication of infrastructure.

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

Yes we agree with this approach. We think it is inefficient for distributors to contract with retailers, who then have to contract with MEPs for the supply of the data – having retailers in the loop is not adding any value, but drives addition transaction costs.

To implement this, Code changes would be required to:

- Enable MEPs to supply data to distributors without specific retailer permission
- Require MEPs to enter into contracts with distributors to supply data
- Limit the use of the data by distributors to permitted network related purposes only.
- Require retailers to include privacy terms in their consumer agreements, which enable MEPs to supply this data to distributors for network purposes.

We also think that the Authority should provide default terms, to produce the same efficiencies in contract negotiations beween distributors and MEPs, as have been delivered through the implementation of the DDA between distributors and retailers.

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

We don't think so. As discussed in Q9, we think it is inefficient for MEPs to supply data to retailers who then supply distributors. It would be more efficient for MEPs to contract with and supply data directly to distributors.

As such, given that new terms would be required for power quality data, as well as the development of information exchange protocols for this data, both of which will be more complex than exchanging HHR data using existing EIEP3 formats, we think the terms developed should be directly between distributors and MEPs.

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

[redacted] Withheld at request of submitter

[redacted]

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

[redacted] Withheld at request of submitter

[redacted]

[redacted]

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?

[redacted] Withheld at request of submitter

[redacted]

- [redacted]

- [redacted]

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 support the introduction of standard terms and pricing which a distributor can opt into, avoiding the delays involved in obtaining specific quotes and development of commercial terms.

We see this working in the same way as the DDA between retailers and distributors, where a retailer can simply provide notice to the distributor that they intend to trade on the network, and the terms and pricing automatically take effect. This would deliver the same benefits as cited by the Authority in the implementation of the DDA, namely reduced transaction costs for all parties.

We would however suggest that the Authority develops the terms and incorporates them into the Code (consistent with the DDA) rather than the MEPs developing the terms, for the same reasons that the Authority rather than distributors developed the DDA.

Default terms should cover:

- Provision of both HHR consumption and power quality data
- Specify whether missing reads are to be estimated, and the methodology to do so
- Standardised data transfer formats
- Timing
- Payment terms
- Obligations on the distributor as to the use and storage of the data

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

We agree that distributor's visibility of DER should be improved, but we think it needs to be completed with urgency. The key reason for this is that if data is not captured as DER is installed, it might not be possible to go back and capture that data. Even non-exporting DER can have an impact on consumption behaviours, and potentially might behave in a non-predictable manner, which has the potential to impact on networks.

We note there are some existing issues. The Authority's comments that distributors have information on the location and size of some DER on their network, because we are required to record it in the Registry (i.e. DG). However while we are required to record this information in the Registry, we don't actually hold the correct information to record. While we 'approve' the connection of the DG to the network, we don't install the import/export meter or connect the DG behind the meter, and there is no requirement on the DG installer to provide us confirmation of what they have installed. As such, we are only able to update the Registry based on what was *approved*, not what was actually installed. We submit that DER installers should be subject to Code obligations to update the Registry, or provide confirmation of DER installed behind the meter for the network to update the Registry.

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

We think that distributors need visibility of all DER, because even while small DER may not have a significant impact, the cumulative impact of a large volume of small DER may have an impact. In particular, large volumes of small DER operating in the same way (for example being co-ordinated by a flexibility trader) has the ability to have a significant impact on the network.

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

To us, 'real time' means that you have a constant and instantaneous link to the DER device by a reliable means of communications such as fibre. This enables our control systems to manage the load and to potentially control the load (directly or via a flexibility trader) within seconds.

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

System Operation

Large-scale DER will require real-time data immediately, particularly as it is generally sized to reflect the current capacity of the network, and therefore will need to be managed carefully. Fibre connections are generally a condition of our network approval for these.

We agree that we don't need real-time power quality data *now* for managing smaller scale DER, but the timeframe in which we will need it very much depends on how quickly small scale DER connections grow. We think it will be required within 5 years.

Network Faults

We do however need real-time consumption and quality information sooner than 5 years for another purpose – managing and resolving faults.

For example, during Cyclone Gabrielle we had over 1,500 tickets open for LV faults. If we had near real-time ability to ping these houses and see if the power had been restored, we could avoid manually calling them or rolling a truck. Real-time information enables us to pinpoint outages, reducing time and cost to resolve faults, and improving customer experience.

As such, we think distributors should have access to real-time data from smart meters now, for the benefit of consumers, rather than waiting until DER connections ramp up.

Future Proofing

While connections to smart devices behind the meter (such as car chargers) might not be required yet, we think it important that the Authority start planning for the standards and communication methodologies that will be required, and regulating what sorts of technology needs to be onboard these devices.

If this is not done, the risk is that these devices will be installed without the necessary onboard comms technology, and when we get to the point of needing the data, the device will not have the capability to provide it.

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?

No comment.

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.

We think the Authority should prioritise amending the Code rather than modifying the Data Template, as the template is currently between distributors and retailers, while MEPs hold the data. As such, it would be more efficient for distributors (and flexibility traders) to deal directly with MEPs who hold the data. Involving the retailer only adds cost and complexity to the arrangement.

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 comment.

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

As identified by the Authority, distributors themselves do not currently have the data required to calculate granular current and likely future congestion data.

Once distributors gain access to the data required to calculate congestion on the LV network (whether thru MEP data or by deploying extensive monitoring devices), the next steps are for distributors to build systems which calculate the congestion using the data, and then to provide tools so that the flexibility trader can view it.

These is a complex modelling requirement, requiring integration of geospacial and physical asset data, and complex power flow data evaluated over multiple periods. As with any complex model of this type, conveying output in a meaningful way requires specialist expertise. These types of models can be created, however the upfront development costs and ongoing management costs should not be underestimated.

Therefore the Authority should consider the time that will be required to obtain access to this data, to build systems to interpret the data, and to build tools to supply the data to flexibility traders. It also needs to consider how and from whom distributors will recoup their costs to supply this data to flexibility traders.

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 comment.

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

No comment.

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. We think it would be more efficient to modify the existing Registry, rather than create a separate additional Registry. Most industry participants already have a tool which interfaces with the Registry, and this would only require minor updates compared to building a new tool for a new Registry.

With regard to the issue around 'the functionality of the registry is such that this is only visible per ICP, after the user has searched for the relevant ICP' this reflects the relative limitations of web interface tool. Most networks have a system which stores an offline version of the entire ICP registry contents for ICPs on their network (and remains synchronised to the Registry), and can then search this data using data analysis tools. Other participants could use the same tools to store registry, view, and analysis registry information for a cohort of ICPs to which they are permitted access.

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

We think the priority should be on addressing the 'basics' such as the flow of data to distributors which are currently operating in an information vacuum, before turning the focus onto how this data can be applied to deliver benefits from DER.

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

No comment

Q28. Do you agree that model privacy disclosure terms are appropriate? If not, why not?

No comment

Q29. Do you agree that model privacy disclosure terms would facilitate data access? If not, why not?

While we think it would be useful for the Authority to provide model privacy disclosure terms, if retailers are not *required* to insert disclosure terms (either the model terms, or their own terms that cover off the same points) then they will continue to be able to cite privacy as a reason not to provide data.

As such we submit that retailers should be required to include disclosure terms which enable them to provide data to networks for permitted purposes. This can either be using the model terms, or their own language that achieves the same outcome.

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

As above.

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?

We are supportive of the Authority providing clear rules around what distributors can and cannot use consumer data for, to provide consumers and retailers confidence that the data will only be used for the regulated network business, and not for any other business.

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

Northpower has robust privacy protection frameworks in place and so would not benefit from generic guidance, if workshops were tailored to discuss and resolve specific data use cases in line with privacy regulations, this would be of value.

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?

We support all of the options identified, but consider a staged approach appropriate:

Option 1 would be useful because we have had limited interaction with and approaches from flexibility traders. Flexibility Trader led forums on the services they can offer would help to build depth of understanding, and introduce key service providers.

Option 2 would be useful to assist in building out distributor understanding and capability in this space.

Option 3 we support in principle and note that we already conduct high level options analysis for investments as part of our investment process. Sharing of learnings from other procurement processes, and standard templates/service specifications for tenders would also be useful. We agree with a materiality being applied, and also suggest tenders are not required until there is a depth of tenderers to respond.

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?

Option 1

We don't believe that distributors would necessarily benefit from education on how to run competitive tenders, as distributors already have to procure equipment and contracting services to build and maintain their networks, including often using tenders for large projects.

Option 2

We think that multiple trading relationships would be beneficial. At the moment, the industry construct does not easily allow us to purchase DER services – while we can contract directly with a DER provider or aggregator, there are high transaction costs because there is no established marketplace. As such, a functioning MTR marketplace would make it easier to acquire DER services.

Option 3

We don't support standing offers at this time because we anticipate it could drive a significant level of work and cost to develop, but potentially with a low likelihood of standing offers being taken up.

In addition, the Authority would need to consider:

- How would the cost of standing offer development be recouped, particularly if the offer was not taken up.
- Risk that a standing offer was only partially subscribed (i.e. you might receive 50% of the volume of the service you require) and a network solution is still required to address an acute network issue. Do we continue to inefficiently pay the standing offer for the term, or do we cease to pay for it given it is no longer required?

Option 4

We support the monitoring of distributor's use of competitive procurement,

Option 5

We already operate under arm's lengths rules in relation to services procured from our contracting business, and as such do not oppose this in principle. However:

- Further consideration would need to go into where the 'line' between the distributor and non-network services is. For example, should ripple control of hot water (which has been distributor owned and managed for decades) be treated as arm's length, simply because it is a form of DER?
- While operational separation is not proposed, we note we do oppose this. We think that operational separation (such as that which applies to generation once it reaches a certain scale) drives inefficient duplication of costs.

Q33. Do you think there are circumstances in which the Authority should extend the Arm's-Length Rules? If not, why not?

No comment

Q34. Do you agree with the Authority that Option 1 should be implemented, and that Option 2 should only be considered in the event of allegations of, or instances of anti-competitive harm in contestable markets (Issue 3)? If not, what alternative option/s would you favour, if any?

We agree that the Authority should monitor the behaviour of distributors (Option 1) and that arm's length rules (Option 2) should only be implemented if an issue emerged that warranted such a response. Otherwise, significant time and resource would be required to go into developed appropriate arm's length rules unnecessarily.

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 think that current shortages of skilled personnel in the electricity industry reflect broader trends in the labour market, international demand for this skillset, and current migration settings. As such, we don't consider this issue specific to the electricity industry.

We don't believe that it is necessary for the Authority to provide guidance on how distributors should collaborate in the future, as have and will continue to demonstrate that they collaborate consistently to deliver benefits to consumers.

By way of example the level of collaboration standardisation on technical standards, network platform development, customer service methodologies, asset management practice, pricing standardisation, and market evolution (to name a few areas) are extensive and demonstrate deep discussion and commitment to supporting consumer outcomes across the sector.

Q36. Do you think it would be helpful for the Authority to encourage the use of joint ventures between distributors to increase their integration of DER and their procurement of NNS projects? And should this be combined with the first option?

We support the Authority encouraging joint ventures, and note that this is already occurring naturally such as with the Northern Energy Group and the South Island Te Waipounamu Distribution Group.

Distributor joint ventures for the purposes of purchasing flexibility services could be seen as exerting bargaining power and from that point of view we think it would be beneficial for the Authority to provide guidance to assist distributors to avoid any regulatory or competition law transgressions.

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?

We agree that there will be value in standardisation of operating agreements for flexibility services, but think the market is too immature to regulate standard form agreements at this point. Rather, sharing of agreements between distributors (as we have done with distributed generation connection agreements) will reduce transaction costs and assist the commonly used templates to develop and evolve. We note the Authority could have a role in collating and sharing standard templates that are being used.

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?

We are confident that if issues develop that stakeholders will advise the Authority, and in addition that as the Authority's work programme continues, there will be further consultations on operating agreements.

Q39. Do you have any suggestions for how the Authority can support industry-led work on providing guidance on best practice and templates for operating agreements?

The Authority could address any potential competition issues associated with flexibility traders sharing agreements and templates (as they are competing) and also play a role in collating and sharing templates and agreements across the industry.

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 think that the proposed scope for the Part 6 review is too narrow, because Part 6 is not designed for the type of large-scale generation applications we are now seeing (of similar complexity to that connecting to the Grid), or the forecast volume and complexity of future DER connections. Significant complexity and uncertainty in the current rules is making processing applications and managing DER inefficient for distributors and applicants.

In particular:

- Review the incremental cost rules and whether they provide the right commercial incentives to distributors, facilitate DG uptake, enable future planning, and are fair to to the consumers who funded existing infrastructure. Review application process and timeframes. Consider a mechanism for amending applications, particularly as they generally develop with support and input from network engineers, rather than being a linear 'approve' or 'decline' of the initial application.
- Review how capacity is reserved or allocated, and how long for, under the current rules.
- Address whether and in what circumstances an application can be transferred to a third party.
- Review whether Part 6 works with other parts of the Code, for example, to ensure EDBs are not put in conflict with grid owner or system operator requirements on one hand and DG requirements on the other.
- Review and align the distributor application process with the queue process recently implemented by Transpower and Transpower connecting processes.
- Review maximum prescribed fees, so they align with those connecting to Transpower and at least reflect actual costs incurred in processing DG applications.
- Review default connection terms to make them fit for purpose for the nature of the generation.
- Review how constraints are managed and whether the Code adequately addresses how changes in available network capacity is managed as network demand changes over time (for example through reductions in load to be offset by generation).

The proposed scope appears tinkering around the edges, whereas we consider a full review necessary for Part 6 to facilitate both largescale DG, and unlock the potential of small-scale DER. As a starting point, industry workshops could identify practical issues and opportunities for improvement.

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

See above.

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

We support amending Part 6 to explicitly include DER.

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

We support raising the threshold for Part 1 applications to 20kW. We note that if it were raised further to include larger applications that could impact the network, the change could actually result in slowing down the process because it is possible more rigour would have to be applied to applications in this group to check for impacts on the network.

However we do not think that the Part 1 threshold is a major issue, nor will amending it materially improve Part 6.

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

See above.

In addition, we think that Part1 (comprehensive) and Part1A (streamlined) for under 10kW is not necessary and should be amalgamated to simplify the process.

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

We do not believe it is necessary to change the 10 business day timeframe for Part 1A.

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

We think that applications under Part 2 require more time to process, due to the complexity of the applications. The key issues are:

- Applications are not straight forward, and generally applicants want to work collaboratively with our engineers to design the lowest cost solution that maximises output across the network, rather than follow the accept/decline Part 6 process.

- Multiple grid-scale generation applications are extremely complex as they are often located at the extremeties of the distribution network, and are sized to maximise the available capacity on the network. They are also competing for limited engineering resource, and pulling that engineering resource from their core network roles to maintain and upgrade the network.

- Transpower process timeframes do not align with EDB's Part 6 obligations

As the Authority points out, an option which we generally pursue is to seek successive time extensions of up to 40 business days, and generally distributed generators are receptive to this. However the risk is that if an extension were not granted, we might have to make a strict accept or decline decision based on the information before us at that time.

We note that Transpower has similar issues in terms of grid-scale connection enquiries, and has implemented a queueing system. We submit that Transpower and EDBs should have similar timeframes to review grid-scale applications.

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

See above

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.

We agree that it does not make sense that an 11kW application goes through the same process as a 100MW application process. We generally find that applications of 1MW-5MW are more complex and have the potential to more severally impact the network, and then 5MW+ tend to become very complex. As such, we would support a threshold of 1MW.

This would produce 3 groups, and align with the price caps (assuming an increase from 10kW to 20kW):

- 0-20kW
- 20kW-999kW
- 1MW+

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

As above

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

We agree there is a lack of guidance as to how to assess competing final applications, and a framework for assessing competing final applications would be beneficial. Please see our response to Question 40 above.

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

We think it should be mandated, and that the Authority should take the required steps including the completion of a regulatory impact assessment.

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

We think the maximum prescribed fees should be removed and instead distributors should be enabled to recover their reasonable costs.

Capping the fees is not cost reflective, and forces distributors to recover the balance of costs through variable (i.e. export) charges, or from load customers. We compare this to the Low Fixed Charge regulations, which similarly forced distributors to recover fixed costs through variable charges, in a non-cost reflective manner.

Parity should also be sought between distributor and Transpower charges in relation to grid-scale generation connections, which have a similar (or greater) level of complexity when connecting to a distribution network.

If you have any queries regarding this submission please contact Shane Ruxton (shane.ruxton@northpower.com)