Updating the Regulatory Settings for Distribution Networks

28 September 2021

Overview

Northpower and Top Energy welcome the opportunity to provide feedback on the Electricity Authority's discussion document: *Updating the Regulatory Settings for Distribution Networks.*

As consumer owned organisations, we are focused on the delivery of efficient, affordable, and reliable network services to our communities. We are cognisant of the potential benefits of new technology and innovation to our community, and the role it will play in supporting an affordable transition to a zero carbon future.

We agree that regulation needs to constantly evolve to ensure we unlock the potential of new technology. We are however mindful of striking a careful balance, so that those for whom new technology is not an option, including those in energy poverty who cannot access affordable electricity to meet their basic needs, are not disadvantaged or end up cross subsidising those consumers who can access these technologies.

With this in mind, the regulatory approach needs to be agile, with the ability to adapt as the environment changes. But to lead to better customer outcomes, and avoid unintended consequences - interventions need to be well founded, evidence based to address a material and enduring problem, and proportionate to the problem being solved.

We see strong consumer benefits in a flexible and light-handed regulatory framework that supports the industry learning and responding in a proactive and collaborative manner and enables innovation to flourish. We also support transparent disclosure by all industry participants to enable informed decision making by participants and consumers. This transparency further provides assurance to regulators that consumer interests are being served.

We endorse and support the submission of the Northern Energy Group, of which we are a member. This submission discusses a number of issues in further detail, and provides specific examples based on our experience.

In summary, we recommend the Authority prioritise:

- Foundational work to support DER integration, primarily the visibility of DER, DG and EVs, as well as facilitating and supporting access to LV information;
- Support for and development of fit for purpose standards;
- Modernising Part 6 of the Code to reflect the increase in and complexities of distributed generation connecting at the distribution level.

For each theme in the discussion paper, this submission provides our view with regard to our experiences of the issues identified by the Electricity Authority (EA), and our views on the options. Table 1 provides a summary of our views.

Table 1: Summary of views

Theme	Our view on the urgency and materiality of issues	Recommended options
Information sharing	Significant	• Continue the collaboration occurring amongst distributors • Guidance for reporting • Data sharing through APIs • MEP default terms
Electricity standards	Significant	• Develop new uniform standards, especially for EV chargers, domestic inverters, and solar farm controllability • Establish a DER registry • Overhaul Part 6 of the Code
Market settings for equal access	Minor	• Disclosure of major investment decisions, including assessment of flexibility options • Disclosure of flexibility trials and terms • Procurement guidelines; tender platform • Support EV charger aggregation
Operating agreements	Minor	• Support development of the market through a DER register and appropriate standards • Develop guidance for operating agreements
Capacity and capability	Minor	• Encourage and support industry collaboration • Increase engagement with EDBs • Improve transparency of investment decisions

We encourage the EA to continue the conversation with EDBs and the wider industry around how we can effectively work together to support an affordable, reliable and sustainable energy future for New Zealand. We invite you to visit our networks, meet our teams and see first-hand the work we are doing to ensure our network is future ready and our consumer owners obtain the full benefits of new low carbon technologies.

If you have any queries in regard to this submission please contact Shane Ruxton on 021 195 9073, shane.ruxton@northpower.com or Simon Bocock on 027 296 8347, simon.bocock@topenergy.co.nz

Theme 1 – Information on power flows and hosting capacity

Q1: Have you experienced issues relating to a lack of information or uneven access to information?

Network data

Networks need data on their LV networks to understand and monitor the performance of these parts of the networks. This is needed both in real-time to support network operations, and to be available later for analysis to support asset management and network design. The key data required is load metrics such as amps and voltage, rather than just half hour consumption data.

There are broadly three options to access this data.

1. Smart meter data provides a multitude of use cases to support an EDB's operations, safety, and customer support functions. It provides individual data points for each consumer, enabling a personalised and targeted service, and should be able to be delivered at minimal incremental cost.

2. An alternative is LV monitoring devices which are installed across the LV network, providing a constant source of quality information, but only at the particular location (not at a customer level). These can be effective if installed widely across distribution substations. We are trialling some of these devices but are reluctant to deploy them at scale as there is potential for this to inefficiently duplicate the function of smart meter devices which are already deployed on the network. They are particularly useful for providing us a view at the transformer, which smart meters are not able to do.

3. The third option would be to install LV monitoring devices at each consumer premise, which effectively duplicates most of the data collected from smart meters.

Both Top Energy and Northpower have attempted and continue to engage with major metering equipment providers and retailers to provide this data but have to date been unable to agree commercial terms and how data can be used. In both cases, the proposed costs significantly outweighed the benefit to our consumers, and therefore, at this stage, obtaining access to this data would not have been in the best interests of consumers.

Other common issues we have experienced include the:

- length of time for MEPs to respond to requests for commercial and contractual terms
- time and cost to develop individual communications protocols for each MEP, due to there being no mandated communication methodologies
- number of MEP participant codes trading on our networks for which the above would need to be developed.

Consumption Data

Half hour consumption is of a much lower priority to us as, while it is useful for billing purposes, it is generally not overly useful for the operation and planning of the network.

Our experience is that half hour data can only be obtained from retailers, and that it historically has only been provided on a one-off basis, for a specific purpose, where we have provided a very large and, in some cases, *unlimited* indemnity in relation to its use and any disclosure, and where the data has been de-identified.

In a practical sense de-identifying means that, if for example we wanted to obtain data on customers at a distribution substation level or feeder level, the retailer would not only mask the ICP number, but they would only send us data on ICPs where they had at least 5 ICPs on the distribution transformer or feeder so that we could not seek to re-identify the data. This limited the use to modelling pricing structures only. In addition, the dataset was incomplete and therefore not useful as a representative sample for analytical purposes.

<table>
<tr><th>Top Energy</th><th>Northpower</th></tr>
<tr><td>Top Energy has been able to negotiate a contract for the supply of HHR data from two retailers, for its implementation of Time of Use pricing as part of cost reflective pricing reform. One was for a small number of ICPs at no cost and the other one was at a cost per ICP for a reasonable proportion of ICPs.

This data was provided on one-off basis for the purposes of pricing only. In addition, the paid data was anonymised and only supplied if there was at least 5 ICPs at the lowest level of aggregation.

Due to the limitations of use, anonymisation, and that it was only a subset of the total customers (less than half), this data could not be used to manage or have visibility on the LV network.</td><td>Northpower did not complete any agreements with retailers to obtain HHR data for its implementation of Time of Use pricing as part of cost reflective pricing reform. This was due to a number of commercial issues including:
• requests for indemnity with large caps, and in the case of one retailer a non-negotiable <u>unlimited</u> cap
• request for excessively invasive audit powers
• being denied permission to share data with third parties specialising in storage and analysis of large volumes of HHR data, forcing us to develop capability and hardware in house to complete the analysis
• exclusion of data in cohorts of less than 5, making the data incomplete and unreliable
• one retailer advised they would not release <u>any</u> data until the Commerce Commission clarified its statement regarding the possibility that bi-lateral data sharing agreements may be anti-competitive.

As we were unable to agree terms, we instead had to implement our Time of Use pricing without access to any half hour data to develop the pricing. We instead implemented very small differentials between peak, shoulder, and off-peak to mitigate our risk while we built up sufficient billing data to set the following year's pricing with larger differentials.</td></tr>
</table>

DDA Data Template

The DDA data template is ineffective for several reasons:

1. It only covers consumption data, and does not apply to the network monitoring data available from smart meters which is critical to network operations (e.g. voltage, load, last gasp, status, etc).

2. It only requires data to be supplied every 6 months, which is insufficient for network operations which require real-time access, particularly when future requirements to manage DER are considered.

3. The data may not be combined with any other dataset without specific retailer permission, preventing the data from being combined with data from other retailers (to analyse an entire network level data set) or with network asset or operational data, or even a network map.

4. The distributor has to provide an unlimited indemnity (which we do not consider commercially reasonable), meaning the risk of obtaining data under the agreement significantly outweighs the benefit of doing.

We note that the ENA developed an amendment to address point 3 which was agreed with ERANZ, however despite this the EA declined to implement the change.

Our primary requirement for data to support the transition to DER is for operational data such as voltage, load, last gasp, on/off status, etc which can be used for both network planning and operations. As such, the DDA template is not fit for the purpose of supporting a transition to DER.

Instead, Top Energy has tried using an alternative approach of writing to retailers requesting their consent to use combined data for network management purpose. However, not all retailers are willing to engage in this method, so a stalemate has occurred preventing the ability to utilise this data for the benefit of consumers.

Q2: What information do you need to make more informed investment and operation decisions?

We see smart meter data, including the operational data discussed above, as critical for the following purposes:

- **Network planning:** smart meter data can show us how our LV network is performing, where we have issues such as low voltage due to excessive load or high voltage due to excessive distributed generation, and where augmentation and/or non-network solutions might be required.

- **Implementation of DER:** two-way electricity flows and significant additional volumes of batteries and solar are going to make the energy flows and voltages across LV networks much more dynamic. 24/7 data capture will be critical to maximise use of the LV network, defer augmentation, and identify issues because they start affecting consumers. Without this data, we are limited to theoretical models of LV network capacity and therefore inefficiently leave wide safety margins.

- **Network operations:** smart meter data can be used to pinpoint outages to enable crews on the ground to restore power faster, proactively follow up on consumers with an outage rather than waiting for them to call us and respond to power quality issues in near real time.

- **Customer support:** smart meter data enables us to drill into issues which consumers might be having and solve issues in real time. For example, we can identify if there is an issue in their area, or if the outage is specific to their property. This has the potential to directly save networks and customers on call out costs.

- **Safety:** smart meter data can be used to proactively identify and resolve broken neutrals at the customer end, which un-remedied can cause serious harm or death.

The data we need from smart meters to deliver these outcomes is broadly voltage, amps (load), status (on/off), last gasp (where the meter sends a signal when it loses power) and power factor. We would need this data in real-time to support safety, customer, and operational outcomes, as well as the ability to save historic data to support network planning.

The specific use cases and associated benefits are below:

Type	Use Case	Benefit
Operational	• Identify if a customer is without power	• Proactively follow-up on ICPs without power. • Identify location of potential issue causing power outages remotely without a truck roll
	• Remote disconnect	• Ability to disconnect and reconnect for safety, and for retailer non-payment. • Improve staff safety from interaction with aggressive members of the public
	• Load control at an ICP rather than aggregate level	• Ability for individual customers to opt in/out of load control dynamically, use load control to respond to network congestion.
	• Monitor power factor & power quality	• Support analysis of installation/connection issues • Improved visibility of potential technical issues that may affect customers • Gives the ability to check that the power level injected by the DG is within the approved limit
	• Broken neutrals	• Identify for safety • Service line safety
Planning	• Voltage monitoring	• Identify ICPs with potential issues to target investment. • Identify where capacity exists for more connections in the LV • Identify where capacity and constraints exist in the LV for DG
	• Peak Load incl. by time • Monitoring load patterns	• Improve pricing signals (e.g. ToU differentials) to improve utilisation of the network • To understand load on distribution transformer, feeder, etc to understand constraints and enable planning. • Providing a better understanding of load growth and changing load patterns on the LV network

Q3: What options do you think should be considered to help improve access to information?

As outlined above, information is critical to the efficient planning and operation of networks, and increasingly so as we move into a world of additional complexity from many more devices and two-way power flows. Therefore, both the availability of information and ease of access need to be addressed.

Complete installation of smart meters

Most retailers have now completed their smart meter rollouts, with a significant way to go until all consumers have access to smart meters. The completion of the smart metering roll out would provide enhanced consumer benefits, through accessing a wider range of energy products (including off-peak pricing, and EV plans). Without completion of these rollouts, some consumers will miss out on being able to participate in DER markets, integration of smart devices, innovative new products, and cost reflective pricing structures.

We are concerned that it is often the more remote, lower socio-economic communities that have not had smart meter rollouts completed, and these communities should not be locked out of future innovation and technologies which might assist to lift them out of energy poverty.

	% of ICPs with communicating smart meter	
	Residential	**General/ Commercial**
Northpower	87%	64%
Top Energy	68%	50%

We support a programme of work being put in place to replace all remaining eligible legacy meters with smart meters, while retaining a legacy option for consumers who choose not to have a smart meter installed. Further extension of mesh networks, and upgrades of communications modules in existing non-communicating smart meters should also be prioritised.

Mandate minimum capability of meters installed

Meters installed should be required to meet minimum capability standards to allow the supply of data which meets retailer and network requirements, and provide a complete service to consumers. In particular, we understand that a large volume of installed smart meters lack the capability to send a 'last gasp' signal. This is where the meter sends a signal that it has lost power which is essential to understand when power has gone out.

Default Terms for MEPs

We suggest consideration be given to default metering agreements to govern the relationship between retailers, MEPs and EDB's.

The EA recently implemented Default Distributor Agreements governing the relationship between retailers and EDBs, on the basis this would provide a level playing field, and reduce the time and cost for networks and EDBs to negotiate with each other.

We consider similar rationale could apply to introducing default terms upon which EDBs can obtain data from MEPs to support the operation and planning of their networks. These terms could limit use of the data to network purposes only to address concerns about the data being used for other commercial purposes.

Once a meter is installed, it is very difficult, expensive, and inefficient to replace it with another MEP's meter. Furthermore, EDBs do not have the ability to select the MEP at an address. While EDBs could look to overbuild smart meters, this would be inefficient asset duplication.

As such, once an MEP's meter is installed at an address, the MEP effectively has a monopoly over providing services at that address. For that reason, we consider the MEP has excessive negotiating power, in the same way that the Authority was concerned that networks did over retailers. As such, a DDA is appropriate to level the playing field.

An alternative to a DDA between retailers and MEPs would be to broaden the existing Data Template (which includes the requirement for retailers to induce MEPs to provide data to networks which the retailer does not hold) to include non-consumption related data (e.g.

load, voltage, etc), but we consider it would be simpler for networks to contract directly with MEPs.

Amend Part 4 regulation to include MEPs

As outlined above, once a meter is installed at an address, the MEP effectively has a monopoly over that address. Part 4 regulation is used in markets where there is little or no competition, to regulate price and quality of goods and services for the benefit of consumers.

MEPs are essentially asset owning companies, in the same way that networks are. There is a risk that, without effective regulation, MEPs could over-recover on their investment, not invest in appropriate meters, or not provide services, to the detriment of consumers. As such, information disclosure and/or default price path regulation could ensure that this does not occur. Information disclosure could cover key metrics such as uptime, communications timeliness, % smart meters, % communicating smart meters, and ensure that MEPs are continuing to improve these metrics and increase their rollouts year on year.

Given MEPs already recover their costs, the cost of their assets, and a return on their investment from retailers, additional revenue received from third parties (e.g. EDBs) should be limited to incremental costs. This will ensure that consumers only pay for this once and obtain the maximum benefit the meter investment can offer.

Communications protocols

Supporting access to metering information requires effective data exchange, which is scalable (e.g. increasing real time data exchange from 30 minute blocks to 5 minute blocks), and suitable for use by all EDBs, MEPs and potentially other industry participants (e.g. aggregators). It is essential that this information exchange is standardised so that it is efficient and supports a transition to a digitised and automated future. We are agnostic as to how this is achieved (e.g. whether by API or centralised data repository) and recommend MEPs and EDBs work with the Authority to determine an optimal solution. We see this as a high priority action.

Theme 2 - Electricity supply standards

Q4: Have Networks experienced issues from the connection or operation of DER?

Operational issues

Material changes in load in either direction can shift voltage, and the transformer needs to respond accordingly. For example, solar installations will push up voltage when they are generating, requiring the transformer to respond in the alternate direction. Similarly, significant load such as EV charging will reduce voltage, requiring the transformer to respond. When the transformer's capability has been reached, investment is required to upgrade the transformer. If this does not occur, inverters will theoretically disconnect in an over-voltage situation preventing export to the grid.

Under-voltage is more difficult to address, and while some car chargers may disconnect, other appliances in the home may be damaged.

Experience on our networks

We have both seen growth in solar, with higher penetration on Top Energy's network.

Top Energy	Northpower
Top Energy currently has 6.6MW of solar export capacity installed on its network, comprising of 1285 installations. This represents 24% of our minimum day time load of 28MW. Significant recent growth in solar, both residential and grid scale. Residential solar has grown by 561 ICP's over the past three years, an 80% increase over that period.	Northpower currently has 6.4MW of export capacity installed on its network, comprising over 1350 installations. Growth has been constant, averaging 199 connections a year in the last three years, with an average installation capacity of 5.3kW per connection.

Top Energy has not experienced any issues caused by solar, however we have needed to adjust transformer tap settings (within normal operational ranges) at the edge of its network to manage voltage, while Northpower has not yet experienced any complaints caused by the network.

To our knowledge, we are not running into widespread issues as a result of DER connections, albeit partly because we don't have access to smart meter in order to detect issues. The only way we become aware of an issue is if a customer contacts us to complain about damage to equipment or loss of ability to export.

We use modelling to calculate available capacity and approve new connections, but as they model the theoretical impacts and include a safety margin, they likely result in lower utilisation of actual network capacity than if we had access to actual data. We are identifying areas of higher PV penetration, and clusters on the LV network and monitoring these sites to validate modelling assumptions and LV hosting capacity, and monitor for any operational issues.

Unbalanced phasing

One issue we do see particular in rural parts of the network, is electricians shifting load at multi-phase installations onto one phase to maximise the self-consumption of solar generation. We use multi-phase installations in rural areas to balance the network, including residential installations. Network approvals require load to be balanced across phases, but it is difficult to prevent electricians reversing this once the installation is connected.

This issue generally comes about because consumers want to self-consume their solar generation, and multi-phase inverters are more expensive. If a transformer becomes unevenly loaded, one of the phases may reach capacity triggering the requirement to upgrade the transformer, even when the other phases still have capacity. This results in inefficient use of assets and unnecessary upgrade costs.

Connection process

Small installations <10kW

We generally find that the process to connect distributed generation of less than 10kW works effectively and is well bedded in. One particular concern we have is that the EDB is required to update the Registry to reflect that the solar is installed, but is not responsible for actually installing the solar, testing the installation, installing the metering, or livening the solar. As such we generally do not know the actual date of install, and the solar installer can’t be compelled to provide us with the installation information in a timely manner to allow the EDB to comply with Code requirements. While we could inspect the installation under the Code, the application fee which is limited under the Code is insufficient to cover this cost, and the additional step in the installation process also provides a poor customer outcome for consumers.

Short of networks taking a broader role to monitor and test everything that happens behind a meter as we move into a DER environment, an effective solution would be that the EA require the retailer to update the Registry with these details.

Larger connections >10kW

The process for connecting distributed generation is complex and cumbersome and does not reflect that those applicants generally want to work collaboratively with the EDB to achieve the most optimal outcome for their connection.

For example, at the point of initial application, applicants generally do not have all of the information set out in the Code. Their final configuration may vary depending on the capacity available and the optimum network configuration. They generally come to us with a high-level idea of what they want to achieve on their site and look to work with us under a collaborative approach to develop an electrical design that achieves an optimal outcome.

Similarly, the information required to be provided by EDBs in response to an initial application is often not required by the applicant, or they may prefer an agile development process rather than the specific response set out by the Code.

Please refer to our suggested changes to Part 6 below.

Q5: Do the Electricity (Safety) Regulations require review? If so, what changes do you think are needed (a) in the near term (b) in the longer term?

Maintaining power quality, avoiding degradation to the network and ensuring safety of installations is paramount. It is also important that New Zealand does not become a dumping ground for outdated or substandard technologies, which will not support DER flexibility services.

The current regulatory regime does not appear to be responsive enough to these emerging issues. We are concerned about delays between updated standards being issued by Standards NZ and the time taken for them to be incorporated into Electricity Safety Regulations and the Electricity Code. Both the Code and safety regulations would benefit from a set process and timeframes for the adoption and incorporation of the latest international standards.

We refer to the submission of the Electricity Engineers Association in support of this point, and encourage regulatory authorities to work closely with the EEA on further development in this area. We see this as high priority.

Q6: Does Part 6 remain fit for purpose? If not, what changes do you think are needed (a) in the near term and (b) in the longer term?

We think that a number of elements of Part 6 do not remain fit for purpose and require an overhaul. The key issues and our proposed solutions are set out below.

Connection Process

As outlined above, the application processes for connections over 10kW are inefficient, and do not reflect the needs of both EDBs and connecting parties.

We recommend there are 4 tiers for applications:

- Less than 10kW (i.e. most standard residential connections)
- 10kW to 1MW (i.e. most medium to large connections, covering cowsheds, commercial premises, etc)
- 1MW to 10MW (i.e. large scale generation)
- 10MW + (i.e. large scale generation which can be or must be dispatchable by the System Operator)

New processes should be workshopped with industry participants and potential applicants, and the processes to apply to EDBs and applicants closely aligned with Part 8 and Transpower's System Operator requirements for embedded generation over 1MW. The current Transpower processes appear to run separately but in parallel to network processes.

Clarification on Transpower's responsibility for, and the co-ordination of, large scale DG over 10MW would be beneficial as it is currently disjointed and potentially results in different approaches across different networks. We would support all DG over 10MW required to be dispatched by Transpower for improved transparency, rather than the current optional approach which is vague and unhelpful.

The above should be a priority as EDBs are seeing significant uplift in enquiry around large scale generation, much of which is in the 10MW-100MW range. Effectively, integrating this new generation will be essential to achieving New Zealand's zero carbon ambitions.

First Mover Disadvantage

There has been a substantial increase in both small scale and large-scale distributed generation connections and inquiry on both networks:

Top Energy	Northpower
Top Energy has 67MW of approved large-scale generation (enquiries of over 400MW) and is experiencing constraints within the network. For example, in the Kaitaia region Top Energy is no longer able to accept large scale distributed generation applications, due to constraints on the single 110kV line between Kaitaia and Kaikohe.	Northpower has 72.5MW of large-scale generation in the pipeline (and enquiries of over 119MW). Effectively the entire western part of the network is now constrained and unable to accept new applications for large scale generation.

The current incremental cost approach provides for either multiple distributed generators to share the cost of a network upgrade, or for one distributed generator to fund upgrades and subsequently be repaid if another distributed generator connects to those assets.

We are now in the position where there is significant natural resource to build new distributed generation on our networks, but it is expected that no individual generators can commercially justify funding the required network upgrades without an assurance that other parties will subsequently connect and partly repay their investment. It is also very difficult to line up multiple distributed generators to construct plant at the same time and therefore share in the investment cost.

As such, to build the infrastructure required to connect significant distributed generation, a funder is required to under-write the investment until such time that subsequent parties connect, and the investment can be recouped. Under the Code, EDBs are dis-incentivised from playing this role because once they invest in a new asset, it is no longer an “incremental cost” and therefore cannot be recouped from generators. In addition, the EDB, on behalf of the load consumers, is carrying the risk and initial cost until distributed generation parties arrive. This is not fair or equitable as load consumers see no direct benefit for this risk.

For example, the existing grid has capacity to export 1GW of energy from Marsden south to Auckland. Transmission upgrades are required to bring generation from areas of natural resource such as the Kaikohe and Dargaville regions, through to Marsden so that it can be transmitted south. To build 1GW of generation will require multiple parties, and a regulatory environment which enables a party to underwrite the infrastructure, because otherwise there is a risk that a single generator will inefficiently build sub-scale transmission, or it will never be built because of the challenges of coordinating so many parties.

We are seeing renewable energy zones (REZ) in overseas jurisdictions, where a party underwrites infrastructure to assist multiple parties building hundreds of megawatts of renewal generation, to support the transition to zero carbon and lower the cost of energy. The EA needs to consider how the incremental cost approach set out in the Code can be amended to incentivise the construction of infrastructure to support de-carbonisation, while still ensuring efficient outcomes in the long run. We suggest this is consulted on, as part of an overhaul of Part 6, and includes a review of overseas experience.

Incremental Costs

The incremental cost set out in the Code prevents cost reflective pricing from being implemented by EDBs, in that it does not allow the residual target revenue (after price signalling) to be allocated in the least distortionary way possible, which would be equally across all customers who benefit from the relevant assets including both load and generation customers by way of fixed charges.

We propose that the Code is amended so that EDBs can spread the cost to maintain and the return on investment that they earn (the calculation of which would still be governed by Part 4 regulation) from both load and generation consumers as the current Code burdens load consumers unfairly. This approach is more cost reflective and also adopts a benefit based approach, which aligns more closely with the approach taken in the proposed TPM.

Application Fees

Application fees are currently capped under the Code. Most new connections are less than 10kW and are capped at $100. Grid scale applications over 1MW are capped at $5,000. These fees have not been reviewed in some time and are not cost reflective because they are inadequate to recover the costs of EDBs in reviewing and responding to initial applications. As a result, load consumers generally have to cross-subsidise generation applications.

We recommend that cost reflective pricing is enabled by the regulatory regime, so that EDBs are able to set these charges to recover their reasonable costs. Applications of >1MW and >10MW should be based on actual time and cost incurred, while lower capacity connections could use standardised rates set based on the EDB's actual average costs for new connections. A similar approach is used for lending establishment fees under the Credit Contracts and Consumer Finance Act.

Q7: Is there a case to be made for minimum mandatory equipment standards for DER equipment, specifically inverter connected DER?

We are cognisant that DER equipment will be primarily designed and manufactured overseas and setting minimum standards may prevent us from partaking in new technology as manufacturers may not adapt their products for our market. In addition, customised technology for the New Zealand market may reduce economies of scale and therefore result in higher cost products for New Zealand consumers.

However, setting a baseline for inverter standards that protect power quality is critical and we should be adopting international best practice. As noted above, it is important that we do not become a dumping ground for substandard equipment that has a negative impact on the grid, the costs of remedy which will drive cost to all consumers.

As outlined in the Northern Energy Group submission, communication capability in DER equipment is going to be essential to support flexibility markets, and consideration needs to be given to the extent to which manufacturers are required to include the capability for internet-based communications between the device and networks, either directly or via an aggregator. In addition, the ability to use this communication methodology to control the device will be critical to respond to price signals, network constraints, and generation shortages. Automated responses will be necessary to achieve large scale responses.

The priority area which could have the largest impact on the distribution network is the uptake of EVs and associated fast home chargers (as opposed to trickle chargers), which unmanaged will create import congestion on the LV networks and drive upgrade costs.

Q8: What standards should be considered to help address reliability and connectivity issues?

There are a number of standards and protocols which will need to be implemented at an industry level to facilitate the large-scale uptake of DER. These include:

- Communications protocols for the provision of smart meter data to industry participants.
- Vehicle to grid (V2G) standards, to ensure safe operation of equipment for NZ installations.
- Protocols for networks or aggregators to communicate with and control EV chargers (or potentially directly with the EV) to optimise charging across the network, avoiding congestion and unnecessary network upgrades.
- Power quality standards to be updated to reflect how congestion will be managed.

In addition, networks have limited visibility of what is behind the meter. It is increasingly important that networks have visibility of DER and new loads or injection sources that exist behind the meter for operational and network planning purposes. This includes batteries, car chargers, EVs, and other devices which may impact on a network. A DER register which captures the installation of these devices would be an effective solution, however some consideration would need to go into how this data could be captured and updated effectively without being unduly burdensome on consumers (e.g. by installers or retailers).

Q9: Is there a case to look at connection and operation standard under Part 6 with a view to mandating aspects of these standards?

Northpower and Top Energy would support industry led development of a set of connection and operating standards which are standard across EDBs, to provide consistency to consumers, retailers, and DER providers. We recommend this is co-ordinated through the EEA, with support from the Authority.

Under current policy settings the uptake of EVs is likely to exceed PVs and batteries, and given a fast home charger can double household load at peak time, we consider the most significant issue is the development of connection standards for EV charging. Smart EV charging can avoid unnecessary network upgrades and supports the development of flexibility services. If action is not taken now, the value will be lost for the life of that asset where it does not have the required capability.

Theme 3 – Market Settings for Equal Access

Q10: What flexibility services are you pursuing?

We currently use load control extensively across our networks, which is a form of flexibility service.

In addition, Top Energy has invested in diesel generation to provide flexibility services to enable essential maintenance on its N security 110kV line in the Far North, manage specific constraints on the network and assist in maintaining power in planned outages.

Both networks test non-network alternatives when considering network investments. While these test cases have yet to identify a scenario where non-network alternatives provided a lower cost and more reliable solution (apart from the above), these alternatives are improving all the time and we expect in the future they may replace or defer some traditional poles and wires solutions. The alternatives we have considered include batteries, diesel backup/peak-support, and remote area power supplies (RAPS).

Q11: Are flexibility services being pursed through a competitive process?

Northpower and Top Energy did not run competitive processes for its test cases but did engage with industry participants capable of providing the services to determine whether there were potential non-network solutions making running a competitive process worthwhile.

Top Energy completed a formal expressions of interest exercise to provide the diesel generation and/or alternative services. However, all external parties required Top Energy to maintain ownership of the existing diesel generation in addition to their non-network solution, which was highly inefficient and highlighted that no alternative market existed at that point.

Northpower recently completed an options analysis to determine the best option to support growth in Mangawhai. We considered 13 options at a feasibility level (outlined below), and shortlisted four (shaded green below) for further consideration. The non-network solutions did not pass the feasibility test. The lowest cost option that met the network need and appropriately managed risk was a new single transformer zone substation. We are happy to share with the EA the rationale for the selection, including the commercial considerations and costings involved.

No.	Option Description
1	Retain the status quo and do nothing to address the constraint
2	Upgrade the current substation to 2 x 20MVA transformers
3	Upgrade the current substation to 2 x 10/15MVA transformers
4	Install new 2 x transformer substation in Mangawhai Heads
5	Install new 2 x transformer substation north of causeway
6	Install new 2 x transformer substation in Mangawhai Township
7	Install new single transformer substation north of causeway
8	Install new single transformer substation in Mangawhai Township **(selected option)**

9	Meet demand by contracting standby diesel generation
10	Install a grid connected battery system to meet peak demand
11	Load transfer to other feeders (from Waipu and Kaiwaka zone subs)
12	Move feeders from Waipu and Kaiwaka from 11kV to 22kV
13	Employ more aggressive demand response to delay investment

Q12: What options should be considered to incentivise non-network solutions?

Investment Test

To give stakeholders confidence that EDBs are applying the most appropriate solution to network constraints, EDB annual IM disclosures could include an investment test which demonstrates the EDB has considered an evaluated non-network alternative for any investments over $10m. As EDBs are already undertaking these tests as part of evaluating investment decisions, we do not consider that including information in disclosures would be overly burdensome.

Innovation Incentive

EDBs are already incentivised under current regulation to implement non-network solutions, because if a non-network solution can be implemented that delivers the same security of supply at a lower cost than a traditional solution, the EDB can make a higher profit or lower the cost to consumers.

If the EA or Government wish for EDBs to implement non-network solutions which are inefficient (e.g. to develop capability or seed markets) they could consider innovation incentives under Part 4 regulation, or direct subsidies. This could include an incentive pool which EDBs tender for.

Tender Platform

The EA could introduce a tender platform similar to the New Zealand Government Electronic Tenders Service (gets.govt.nz) or Tender Link, where participants could advertise their flexibility requirements and providers could tender to provide solutions. EDBs could use this platform to seek non-network service alternatives for investments, as well as potentially lower cost investments where it is efficient to do so. This would enable EDB's to identify the issue and tender for a solution, rather than devising a specific solution and tendering for a cost to build that solution.

Asset Management Plans

Asset Management Plans could include more information on constraints, including setting out expenditure which is intended to be incurred to address constraints. Non network service providers could then contact the EDB if they believe they have an alternative solution which provides a superior cost and security of supply.

Q13: What options would encourage competitive procurement processes for flexibility services?

Tender Platform

We support a tender platform as outlined above.

Future Development of a Dynamic Marketplace

We expect that in the future there will be a dynamic marketplace, where flexibility services can be traded and put to their most efficient use. However, EDBs need certainty that flexibility services will be available when called upon, and as such might need to either enter into hedges or purchase semi-permanent and/or reserve capability in order to ensure flexibility services are available when called upon and avoid the outages that might otherwise occur. As such, there is likely to be a place for both the tender platform and a dynamic market in the future.

A suitable regulatory environment including clearing manager similar to the existing electricity spot market would be required, or flexibility services could be integrated into the existing market. We see this as a long-term development, once the cost of new technologies reduces to become more competitive with traditional "poles and wires" solutions.

Q14: Have you experienced difficulties with negotiating operating agreements for flexibility services?

Not applicable.

Q15: Are the transaction costs of developing contracts a barrier to entering the market for flexibility services?

Non-network solutions need to offer a lower overall cost to EDBs (including transaction costs) at the same or better quality of supply, to provide a more efficient outcome for consumers.

Transaction costs of engaging a flexibility service provider include defining the service procured, defining performance standards, ensuring the provider is able to provide the service when required (as the EDB has the overall obligation to meet service requirements) and financial strength to indemnify an EDB for failure to deliver on its services, to commercials (including agreeing pricing, billing, payment, governance requirements), and integration of new technologies into operational procedures.

At this stage of market development, the real issue is a lack of suitable providers of flexibility services who can offer a lower total cost compared to traditional solutions, not the transaction costs of negotiating agreements. As noted above, the focus at this stage should be on improving information and visibility of where DER is, to highlight to market participants where opportunities exist to develop flexibility services.

However, as these markets mature, increasing visibility of the terms on which flexibility services are provided, the service specifications and operational terms that apply would be valuable learnings for all industry participants. We suggest this is something that the EA could assist, in developing a forum for sharing this information, and mandating the disclosure of flexibility terms after a certain period (e.g. 18 months) to enable all participants to build an understanding of the value of these services.

Theme 4 - Operating Agreements

Q16: Would an operating agreement help lower transaction costs and level negotiating positions?

We don’t expect that an operating agreement would materially lower transaction costs, because agreeing an operating agreement up front is a relatively minor cost in the overall cost of integrating a new type of supplier and technology into a network’s operating model.

In time standardised operating agreements could provide some assistance in standardising procurement of flexibility services from different vendors. However to truly lower transaction costs there needed to be a structure that manages delivery after signing the agreement as well. A network is accountable if a flexibility service fails to deliver, for example, resulting in a blackout, and therefore the flexibility service provider should have the same level of accountability under the Code as a generator who fails to deliver causing an under-frequency event. This requires a supporting framework to be developed, which could be undertaken at a national level.

Q17: What kind of operating agreement would address the issues described in this chapter?

See above.

Theme 5 – Capability and Capacity

Q18: What are distributors doing to ensure their networks can efficiently and effectively manage the transformation of networks?

We are both working to implement the recommendations of the Network Transformation Roadmap as well as other actions to ensure our networks are up to date and ready for future transformation, including:

- Upgrading our ADMS systems to ensure greater visibility and control of our HV networks, and a pathway to LV visibility and control
- Improving LV visibility and data capture
- Projects to model and map our LV network capacity and constraints
- Ensuring our DG standards are up to date and future focussed
- Undertaking trials to understand the impact of DER and DG on the network, testing against modelled assumptions in order to validate hosting capacity and trigger points for network upgrades
- Developing a strategy to gain real-time visibility of our LV network
- Upgrading systems to be resilient and cyber secure, and automating processes.
- Implementing cost reflective pricing

Top Energy	Northpower
Top Energy has engaged an external capability review to understand the resource requirement to manage the operation of DG and the resultant DSO requirements. On top of the investment made in systems identified above, a 10% increase in staff is expected over the next 18 months.	Over the last 4 years Northpower has materially increased it's resourcing, investing in core areas of asset management, operations and customer experience. We are continuing to assess the capability required for future networks, and have recently appointed a future networks engineer, with a focus on DER integration.

We are cognisant that we need to time investments to achieve efficient outcomes. Too early could burden today's consumers, while too late could mean consumers miss out on the opportunities afforded by DER and new technologies. As such, we are employing a learn, adapt, and respond approach to avoid regretful spend.

Q19: How are distributors currently working together to achieve better outcomes for consumers?

Networks are increasingly working cohesively together to share knowledge and create efficiencies to drive down cost and ensure consumers get the benefits of a low carbon energy future. We recognise that the future challenges can't be solved by one person, and that it is important to enable experimentation and innovation. Mechanisms are in place that successfully encourage the sharing across EDBs of diversity of thought and experience. This includes the ENA and its specialist working groups (covering pricing, regulatory, sustainability and new technologies) along with the EDB IT Leadership Forum, Risk Management and Health & Safety groups.

As consumer owned organisations, we are cognisant of our core responsibility to support our consumers to transition into a low carbon energy future, which is affordable and equitable for all users. As neighbouring networks who share many of the same stakeholders, we are working together to accelerate our progress and share our learnings. Examples that we are involved with, in addition to those above, include:

1. Network pricing, where Northpower and Top Energy have jointly consulted with retailers for the last 3 years on their annual pricing changes and have aligned their pricing reform. This is creating consistency across the region and reducing complexity for retailers.
2. The implementation of Salesforce as a CRM, where Top Energy, Northpower, and Counties Energy have shared expertise and experiences to assist each other and accelerate progress with their implementations.
3. Standardising annual customer surveys to benchmark performance across key deliverables including service, communications and reputation.
4. Joint public safety campaigns.
5. Implementation of GE PowerOn ADMS systems, and standardising operational procedures.

The Northern Energy Group, which together represents nearly 40% of New Zealand's electricity consumers, is another example of this collaborative approach, led by CEOs and senior executives, and is focussed on ensuring that we effectively support our consumers with this transition. Our key principles and roadmap are outlined in the Northern Energy Group submission.

Q20: Could more coordination between distributors improve the efficiency of distribution?

EDBs are leading with increasing levels of co-ordination and collaboration as we prepare for a future that looks quite different and more complex. Based on our experience and what we are seeing across the industry, we expect this co-ordination to accelerate as we learn from each other and deliver for our consumer owners.

While this coordination is happening organically, encouraging reporting of trials by distributors and DER providers in a standardised format, could be helpful to ensuring the wider industry is aware of those learnings.

Finally, we note the EA's paper notes that the evidence is not conclusive about whether economies of scale are an issue. However, the EA does not reference the TDB Advisory report which was commissioned by a group of EDBs and generator-retailers for the Electricity Pricing Review in 2018. This economic analysis concluded that customer density was the key driver of cost and there was no robust evidence of sizeable efficiency gains from amalgamating EDBs.

In our view, coordination can drive efficiency and reduced cost to consumers (and this is occurring already), but it is unlikely to make a material difference to the total cost. Rather, as we outline in this paper, and that of the Northern Energy Group, to ensure cost is not unnecessarily driven into the system, it is critical to act now to get in place the right standards, provide for the sharing of key network data, and enhanced visibility of new technologies (including DER and EV charging).