23 September 2021

Submissions
Electricity Authority
PO Box 10041
Wellington 6143

By E- Mail to distribution.feedback@ea.govt.nz

Re: Counties Energy Submission on "Updating the Regulatory Settings for Distribution Networks - Improving competition and supporting a low emissions economy"

This covering letter provides insight into the benefits Counties Energy has obtained in being the industry leader in low voltage visibility which includes developing a platform, algorithms and a customer outage app that utilises the low voltage data. This has resulted in improved customer services, better operational staff utilisation and optimising of investment decisions[1]. It will also mean that Counties Energy is at the forefront of maximising the benefits of DER integration.

Access to low voltage network data has been through a six-year legacy meter replacement programme in conjunction with Intellihub Limited. Data is accessed through a meshed-wireless network metering communication system that provides instant updates on power outages and power restorations. In addition, power consumption, voltage alerts and other meter data is read remotely every four hours and uploaded to Counties Energy's INDI platform.

INDI is a cloud based big data platform developed by Counties Energy that utilises Google Maps, real-time company vehicle tracking and Counties Energy's GIS network data. INDI, through a series of projects, has provided the following benefits

1. Outage management

   When outages occur and have been repaired, the ability to check that all supplies have been restored (particularly to those customers on spur lines) reduces unnecessary restoration delays and thus improves customer up time.

2. Non-Standard System Operation Voltage Monitoring

   When the network is running in a non-normal arrangement (e.g. "back-feeding" during a fault) the actual voltages at customers premises can be checked to identify any requirements to maintain statutory levels. This has enabled Counties Energy to identify an intermittent voltage quality issue on its network and install voltage regulators to resolve it.

[1] Further details are provided in section 6.1 of our 2021 AMP.

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3. Voltage Complaints Investigations

   The ability to pro-actively identify voltage problems (high and low) to help improve compliance with regulations and also reduce the risk to consumers from faulty neutral wiring. This work resulted in Counties Energy winning this year's Electricity Engineers' Association Public Safety Award[2].

4. Feeder Design

   Better network investment decisions from being able to use real data (e.g. voltage levels) when considering capacity upgrades (e.g. feeder conductor upgrades).

5. Customer Uptime Analysis Report

   Rather than the traditional focus on power outages this looks at the availability of power to a customer. Data can be selected at overall company, GXP, Zone substation, distribution transformer and individual ICP level. It is intended to use this data to identify specific areas where there are opportunities to improve our customers service experience.

6. Customer Outage App

   Counties Energy has developed a customer outage app that provides the real-time outage information to the customer. This includes the outputs of algorithms that can identify the area of the fault and attribute it to network assets such as transformers and feeders. The app also provides near real-time information from fault staff on repair times and allows for customers to report faults back to Counties Energy's call centre. This work resulted in Counties Energy winning the 2019 Energy Excellence Awards for Network Initiative of the Year[3].

7. Major Storm Events

   In major storm events widespread faults can occur in a very short period of time, which can quickly overwhelm call centres, control rooms and fault staff. This compares to big data platforms like INDI that can instantly scale with algorithms designed to analyse faults, give real-time information as the network is restored and provide real-time information to customers.

8. Distributed Generation Optimisation

   Distribution networks are designed for power to travel from the nearest GXP to the customer premise while ensuring regulatory voltage levels are maintained. The capacity for the network to accommodate significant distributed generation customers.

The above illustrates that Counties Energy is New Zealand's leader in low voltage visibility, which required Counties Energy to invest in the development of a complex software platform, algorithms and a customer app. Similarly, this platform will enable Counties Energy to be be at the forefront of DSO developments.

[2] https://www.eea.co.nz/Site/awards-new/
[3] https://www.energyawards.co.nz/content/counties-power-putting-smarts

Counties Energy's leadership demonstrates that EDB capability and capacity is not a matter of economies of scale. This leadership is the result of a long-term commitment to improving customer service and obtaining efficiency gains that go beyond the timeframes, and limited high voltage SAIDI and SAIFI quality frameworks, of the Commerce Commission price-quality path.

Below are Counties Energy's answers to the discussion paper's submission questions.

Yours sincerely

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General Manager Commercial

Updating the Regulatory Settings for Distribution Networks

Improving competition and supporting a low emissions economy

Submission on Discussion paper

Submitter: Counties Energy Ltd 14 Glasgow Road, Pukekohe, Pukekohe Hill 2120,

Responses to Questions: -

Q.1 Have you experienced issues relating to a lack of information or uneven access to information?

The majority of meters on our network are modern smart meters provided by Counties Energy (Downstream Technology) and thus we have excellent and immediate access to information for these customers. However, the lack of access to the remaining customers meters creates problems, especially if they are of significant size. In addition, we cannot offer the same level of monitoring of service quality to those customers.

Q.2 What information do you need to make more informed investment and operation decisions?

Access to the remaining smart meters would allow us to fully check system conditions at a customer level under both normal and abnormal arrangements thus optimising investment decisions and providing all customers with optimum performance.

With the expected development of non-network solution commercial offers, full data will allow for the most appropriate overall decisions to be made.

Q.3 What options do you think should be considered to help improve access to information?

Counties Energy encourages the EA to implement a central meter data store (CMDS). A CMDS would most appropriately address the current issues around timeliness, standardisation and process with regard to access to data for distributed generation. In addition, a CMDS would fully address the current access to data constraints that the EA have attempted to resolve with the implementation of the Default Distributor Agreement (DDA).

Q.4 Have networks experienced issues from the connection or operation of DER?

We have several larger (>1MW) generation plants connected to our distribution system. From a technical perspective all have experienced issues when initially connected (overvoltage, unexpected tripping, etc), which go through a process to be resolved by revision to control and protection settings through an interactive process with plant owners. Improvements to standards will help address these issues.

However, our primary concern is over the present financial arrangements which we believe are restricting the installation of DER. Currently DG line prices are limited under the Electricity Industry

Participation Code (Code) to not being able to exceed incremental costs. This is in Part 6, Schedule 6.4 clause 2(a) of the Code that states: "connection charges in respect of distributed generation must not exceed the incremental costs of providing connection services to the distributed generation."

This is creating two fundamental issues that will limit the future uptake of DG in New Zealand:

1. The first is that DG connections incur very low incremental costs because there is normally available capacity on the network for the first applicants. Once the capacity is fully utilised, and a part of the distribution network is congested, the cost for the next DG to connect is enormous and could include things like having to reconductor a whole feeder.

   This would be less of an impact if small residential DG (i.e. solar) was being connected, but this is increasingly not the case and large solar and wind farms are being connected that will congest significant parts of EDB networks quickly and prevent future DG connections. Counties Energy has seen this occur with a significant area of its network being constrained from one windfarm, which is stopping new DG from connecting.

2. The second issue is that incremental pricing provides no incentive for EDBs to invest in their distribution for future DG growth. There are two reasons for this: (1) if an EDB upgrades its network before the DG connects, then a DG customer can connect without contribution towards the upgrade costs. This is because the cost is already sunk and the Code only requires for the additional, incremental costs, to be recovered; and (2) an EDB is unable to charge for the future costs through recovering the allocated network infrastructure as currently occurs for all the EDBs other customers.

   Again, this is more of an issue than it initially appears because EDB networks are not designed for a large amount of DG export load. Therefore, the available export capacity is significantly less than the amount of capacity to provide demand. If DG is to support large scale DG, then EDBs network design will need to change, and this will require EDBs to invest in their network.

The above issues have occurred on the UK distribution networks, where it is understood that UK EDBs can only charge incremental connection costs. As a result of this, and generous government subsidies, the UK network is export constrained, which has limited the UK's renewable DG uptake.[1]

Q.5 Do the Electrical (Safety) Regulations require review? If so, what changes do you think are needed (a) in the near term and (b) in the longer term?

An area of concern that does not appear to be given adequate recognition is the impact of smaller scale DER on LV networks. A number of studies have shown that at higher levels of DER penetration, when a fault occurs the impact of the generation can be such that the fault current fed through the fuses at the distribution transformer may be reduced such that it does not operate – or is significantly delayed in operation. Similarly, the voltage on the inverter output may not drop to the level at which the undervoltage relay will operate.

See for example "Managing fuse protection in low-voltage networks with distributed generation,

[1] (Refer https://bhesco.co.uk/blog/national-grid-constraint-curtailment-electricity-network)

Green Grid report, 2019." [2]

Under the traditional single direction power flow, the system was effectively fail-safe and only required checking and intervention when a fuse operated. This will no longer be the case and as DER penetration levels increase it will be necessary to establish a system to actively review the LV network to identify potential risk areas. This will require (scarce) engineering resources and will add operational costs.

Q.6 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?

As noted in our response to Q4 we believe the present approach to costs is producing sub-optimal results and limiting the opportunities for the installation of DER.

A second issue is the present two-stage approach for the connection of DER. From our experience the two-stage approach to interfacing with customers proposing to install DG is no longer optimal. The small (under 10kVA) process is well established and streamlined, we believe this is working well for all parties.

We are experiencing an increasing number of proposals for larger schemes, but not at a significant capacity (say greater than 0.5MW output). We believe the process for larger schemes is appropriate for greater than 0.5MW as this level can have a significant impact on smaller rural feeders and thus should be retained.

However, there are many industrial, commercial and other customers (schools/churches) investigating schemes between 10kW an 500kW and we believe that a less onerous approach should be able to be taken to these schemes. Typically, PV schemes in the order of 30kW can be optimal for commercial and smaller industrial customers and a simplified approval process could help with uptake.

Q.7 Is there a case to be made for minimum mandatory equipment standards for DER equipment, specifically inverter connected DER?

Our main concern regarding standards is the very slow updating of specified documents. Whilst appreciating there are processes to go through, MBIE both produces the standards in one part of its organisation and mandates them in another part. Citing standards that are two revisions out of date is clearly sub-optimal. The Standards process is designed such that the full suite of current standards is fully compatible and issues arise with using out of date versions on standards.

We would note that using out-of-date standards is both limiting the adoption of a more flexible approach to connecting DG to the network as well as allowing obsolete equipment to be imported and sold to customers.

[2] https://ir.canterbury.ac.nz/bitstream/handle/10092/16920/UC-GG-19-R-RVH-01%20-20Managing%20fuse%20protection%20in%20lowvoltage%20networks%20wit....pdf?sequence=2&isAllowed=y

Q.8 What standards should be considered to help address reliability and connectivity issues?

We suggest that a comprehensive review of the existing standards, regulations and other documents that impact on the electrical supply system should be undertaken to establish what changes or additions are needed to produce a cohesive set of regulatory instruments.

This should start at the customer end of the system, noting that the majority of items connected by a customer are manufactured to an overseas (usually international) standard or specification.

This should then define all of the characteristics that need to be met by the supply system at the customers point of connection. On the basis that one customer should not cause supply quality issues to another customer it will then be necessary to consider these characteristics and the actual supply system to quantify the available performance against the physical and other restrictions that exist. (e.g. remote customers fed from long rural lines vs. customers in high density urban areas).

From a frequency tolerance perspective the existing grid limits should be reviewed, modelling the expected future mix of generation as well as the current mix. Actual events on the existing system should be reviewed as a starting point and then alternative mixes of both bulk generation and distributed generation considered. This should include consideration of the likely future penetration of batteries both at a grid and individual customer level.

The result of this review should be a comprehensive and coordinated set of standards and regulations to assist all parties in order to improve competition and support a low emissions economy.

As part of the overall review a process needs to be established to ensure that revisions to standards or new standards are rapidly reviewed and adopted quickly. This will better serve all parties involved.

Q.9 Is there a case to look at connection and operation standards under Part 6 with a view to mandating aspects of these standards?

We believe that this approach could assist with implementing non-network solutions for the majority of situations. However, a provision to negotiate specific technical requirements to meet unusual situations would be necessary to ensure the overall supply standards are met. An example of this would be the addition of a service where others already exist and there are network constraints e.g. a load at the end of a long isolated feeder.

As noted in Q 7 any such agreement would need to be updated when Standards are revised to ensure all aspects remain in step.

Q.10 What flexibility services are you pursuing?

From a network investment perspective Counties Energy has a standard requirement for all business cases to investigate non-network solutions and has built up its own operational experience with a grid-connected battery.

We regularly seek pricing for non-network solutions as part of the business case process for major project investments

As part of the contract negotiation process with larger customers loading levels, including shedding options are reviewed.

As a trust owned company, we seek to minimise the total price paid by the end customer and thus have fully maintained the traditional “ripple control” system which benefits us in delaying network investment requirements and reduces Transpower transmission charges, both of which directly benefit customers.

Q.11 Are flexibility services being pursued through a competitive process?

Competitive pricing is sought for specific non-network solutions (e.g. batteries) for each business case. Individual commercial discussions take place when larger customers are being established to explore load shedding options.

Q.12 What options should be considered to incentivise non-network solutions?

Rather than seeking to incentivise any particular approach to a network problem, we believe all options should be compared considering costs (initial and ongoing), proven achievable benefits and the risks of failing to perform as claimed. We do not believe that cross-subsidies (e.g. from tax-payers) to some selected options will produce the best economic outcome.

Q.13 What options would encourage competitive procurement processes for flexibility services?

As noted elsewhere the availability of full detailed data to provide for accurate analysis is a key aspect of considering flexibility services.

We would note that all expected network constraints for the next 10 years are identified and published in the annual Asset Management Plans. This proposed network reinforcement information is provided in detail for the immediate future, including financial data. Thus, a commercial provider of non-network solutions can identify possible opportunities for their services and present them for consideration. (Note consultants and contractors already use the AMP for such purposes).

Q.14 Have you experienced difficulties with negotiating operating agreements for flexibility services?

Default Distributor Agreements provide for the use of load control which is the primary non-network tool presently available.

We do not have any specific experience to provide further comment.

Q.15 Are the transaction costs of developing contracts a barrier to entering the market for flexibility services?

Based on our experience with the negotiation of larger DER contracts the legal costs associated with refining documents is often very significant, reflecting the issue of risk and liability. These items can distort the negotiation process when the negotiation cost is compared to the actual benefits being received by either party.

Q.16 Would an operating agreement help lower transaction costs and level negotiating positions?

Possibly, however any such agreement will need to consider all aspects of the offered services including the risks and liabilities of non-performance, both for the network owners and their existing customers.

Q.17 What kind of operating agreement would address the issues described in this chapter?

A DDA style operating agreement, with the flexibility for both parties to negotiate amendments to the standard DDA terms, would most appropriately address the issues. Given the number and significant capacity of the applications currently in the pipeline throughout NZ, Counties Energy would encourage the EA to seek to implement a DDA style operating agreement at the earliest opportunity.

Q.18 What are distributors doing to ensure their network can efficiently and effectively manage the transformation of networks?

Networks need to be designed to meet the peak demand no matter how this is created and the challenge is to ensure that investments are only made when justified. Thus, managing the demand forms part of this optimisation. It is rare that distributed PV generation will contribute to reducing peak load demand for our network as peaks occur during the winter evening when there is no solar output. This may change with an increased penetration of house size batteries or back feeding from (charged) EV's.

Whilst it is possible to reinforce all parts of the network to meet increased demands (and care is taken in design to allow for flexibility when reinforcement is required) – once plant (lines, cables, transformers) is installed it is very rarely economic to remove it and replace with smaller sized items. Investing in additional assets is therefore a "just in time" exercise.

Thus, the focus of distribution planners is to monitor all parts of the network to detect trends and only when full capacity is reached, to take action. This is significantly aided by more accurate and detailed data being available.

The actual load monitored reflects all factors – normal customer load, load control, installation of PV or other DG, the growth of EV and anything else that happens.

By ensuring we have full, detailed and accurate network data we can consider any alternative options that are developed in a fair and accurate fashion.

Q.19 How are distributors currently working together to achieve better outcomes for consumers?

Counties Energy has a long history of working with our neighbouring networks dating back to Power Board days. When network reinforcement has been required near boundaries then alternative solutions have been investigated to ensure optimal solutions are adopted.

We do have some ability to connect between networks, however it is of note that the interconnection capacity between networks at feeder voltage is limited for both of our neighbours. This demonstrates that the existing networks are both close to optimal for the customers supplied. (i.e. neither network has significant spare capacity).

When interconnection is required (e.g. to back-feed during a fault), control rooms liaise to check the actual capacity available at that time and monitor loading to provide the greatest benefit to customers.

In specific cases larger customers (including generators) have sought alternative connection solutions and costs from the adjacent networks and there are examples where the customer has chosen to connect to the neighbour as it provided them with an overall more attractive solution.

Q.20 Could more coordination between distributors improve the efficiency of distribution?

As noted in our response to Q19, there is no evidence that the present arrangmeents between Counties Energy and our neighbours have resulted in any inefficiencies in the establishment of our networks.

When looking at a reinforcement requirement at the edge of the network, planning staff will investigate the alternative of seeking reinforcement from an adjacent network which will form part of the overall analysis and would need to be included in any business case. Larger potential customers will seek alternative network connection costs as part of their overall site selection process.

At an operational level control engineers liaise to provide the best results for customers.

There are ongoing informal discussions through such groups as the EEA NZ (Inc) and other professional and engineering organisations.

We do not see that imposing a formal coordination process, with its associated costs, would produce sufficient benefits to be justified.