Powerco Limited
35 Junction Street
Private Bag 2065
New Plymouth 4340
0800 769 372
powerco.co.nz

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

Via email distribution.feedback@ea.govt.nz
CC: regulation.branch@comcom.govt.nz

Updating the regulatory settings for electricity distribution networks

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

Defining new services, and the market mechanism for providing them (including how they priced), is a task the Authority is well-placed to support. The Authority's paper canvases a range of topics related to what the market might need in future. Our summary position on the five themes is below:

Power flows and hosting capacity	• Data requirements are specific to the nature and scale of decisions being made • More information will enable more informed decisions from all stakeholders – it's broader than congestion and EDB investments • We are keen to support investments by procurers and suppliers of services in the electricity market
Electricity supply standards	• Review standards and regulations periodically eg 5-yearly] • Review the +/-6% voltage limits as they are too narrow / outdated • Broadening Part 6 from DG to load is appropriate in principle but there are complications to address
Market settings for equal access	• Related party requirements are the natural starting point for assessing any concerns about competitive procurement value • Review the nature and scale of non-network solutions considered in Asset Management Plans to assess what's being considered, and what's not • Consider requirements on projects over a cost threshold eg, $5m
Operating Agreements	• We're going to market for non-network solutions in the Coromandel • Contract development is a relatively small part of the entire process • Too early to standardise terms – better to maximise flexibility
Capability and capacity	• More is needed to clarify this theme and guide future actions • Our 2021 Asset Management Plan outlines our plans to efficiently and effectively manage the impacts of decarbonisation on our network • Meaningful engagement with customers and stakeholders is vital to matching the network service to customer expectations.

We're keen to help More work is needed to translate the options analysis to reality and we're keen to help with that. The Authority has said "*After assessing all stakeholder feedback, specific options will be assessed in detail and a preferred option will be identified and released for consultation*". A better approach would be to assess the potential issues in enough detail to allow clear articulation of any problems, and guide the nature, prioritisation, and timing, of effort.

More clarity needed To make progress, analysis is required to address the issues raised in the Authority's paper. Despite their face-value sensibility, it's too soon to consider options to solve unquantified problems because there'll be a cost ultimately borne by consumers. The Sapere analysis does not provide an assessment of the potential benefits from addressing the issues raised in the Authority's paper - that wasn't its scope. Completing this additional work would guide where to prioritise effort, and when to do it. Only after that task is complete can an options assessment commence. That will ensure issues are identifiable and quantified and any proposed solutions have a measurable benefit that's attributable to them.

Our submission also includes two attachments:

- Attachment 1 contains our submission to the Commerce Commission's open letter on fit-for-purpose regulation of energy networks. It summarises the issues and considerations from a system level and with a customer focus – in that context we implicitly treat the Electricity Authority and Commerce Commission regulatory regime, and objectives, as one.
- Attachment 2 contains material from our 2021 AMP on major projects and the solutions considered

If you have any questions about this submission, please contact me at Andrew.Kerr@powerco.co.nz.

Yours sincerely

Andrew Kerr
Head of Policy, Regulation, and Markets

Theme 1: Information on power flows and hosting capacity

Key points:

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

Detailed responses

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

There are differences between the needs of different parties to provide different services. In addition to load, distributors are also interested in Volts, Amps and power factor.

We are preparing a consumption data request and optimistic about the outcome. Data access has been restricted because of the complicated relationship with retailers and/or meter providers. To date, efficient information sharing has been largely impossible. We support the Authority continuing to monitor the effectiveness of new arrangements for consumption data requests. A future need we see is advanced future network management applications requiring real time AMI data, and the associated communications, latency and accuracy requirements.

Our concern is less about the “reasonable terms” focussed on in the paper, but about the inherent design of the arrangements to reduce the quality of data through time. Access to data is manageable but permission to join is negotiated. Retailers are not obliged to respond. The current arrangements require a retailer agree to how data is combined with other data sets. If all retailers agree, all of the time, then there is no impact on data quality. If they don’t, and customers switch retailers, then as time passes there will be a patchwork of data gaps, reducing the coherency and usefulness of the data.

This is best illustrated by the chart below which shows how customers switching between agree/don’t agree retailers results in a dataset which is the sum of mismatched parts.

		Time period									
		P1	P2	P3	P4	P5	P6	P7	P8	P9	P10
Customer	1	1	1	1	3	1	4	4	4	4	1
	2	1	1	2	4	1	4	1	4	4	1
	3	1	2	2	4	1	1	1	1	1	2
	4	2	2	3	1	2	1	1	1	1	2
	5	2	3	3	1	2	1	2	1	1	3
	6	3	3	3	1	3	2	2	2	2	3
	7	3	3	4	2	3	2	3	2	2	3
	8	3	4	4	2	3	3	3	3	3	4
	9	4	4	1	3	4	3	3	3	3	4
	10	4	1	1	3	4	3	4	3	3	1

Key
Retailer 4 doesn't agree to combining
Retailer 3 partially agrees to combining
Retailers 1&2 agree to combining

The end result: the data series can get ‘broken’ by a combination of switching and retailer agreement. In the example above, there is no customer data set that is usable for the entire 10 periods (to see this, look along each row and imagine creating a trend from only the green or green/orange data set). Furthermore, IS systems need to be developed to manage a patchwork of data capturing each retailer’s approved data combinations, time periods that applies to them, and disposing (if applicable). It doesn’t seem like an ideal outcome to design for (or to incur additional costs to bypass or duplicate).

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

Infrastructure investment and operation decisions are driven by many factors and will evolve through time. The time dimension is important here, as is the nature of the uncertainty we face and manage over different time periods. This is reflected in Attachment 2 which includes an excerpt from our 2021 AMP discussing major projects. This highlights the range of investment drivers (growth is one category), and the range of factors influencing the timing and nature of investment.

One of the key issues we face providing a clear and meaningful picture of hosting capacity is the absence of good network visibility, particularly on the low-voltage network. It is one of the key areas where we expect the Commerce Commission will have to make additional expenditure allowances ahead of the actual need requiring it (whether it be from the Authority or otherwise).

Information that would support informed decision making right now includes:

- The timing and scale of policy decisions affecting electrification needs and decisions by consumers and businesses
- Effective network management and maximising DER hosting capacity (or limit congestion) will require real- or semi-real time network operational information, at a highly disaggregated network level.
- Post event data is of limited value to flexibility traders or network operators. It has value for planning purposes.
- Plans of local government and Government agencies
- Forecasts of environmental conditions
- Forecasts of labour and production costs over the long-term, including carbon prices
- Consumption and power quality data. This includes information on forecast customer needs such as reliability and load (min, max and profile).
- Network connectivity and asset information, plus connection details (phase, fusing etc)
- Better/common information on trends in the costs and capabilities for new technologies (helps the assessment of network investments against flexibility alternatives, and optimise timing)

We are keen to work with the Authority and stakeholders on what data (congestion or otherwise) will support investments by procurers and suppliers of services in the electricity market.

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

A focus of the Authority needs to be clarifying the definition of “hosting capacity” and its role informing investment and pricing. For example, a static picture of the worst-case scenario will provide very different information to a dynamic assessment which includes time-of-use and seasonal considerations.

Some options to add to the list include

- The Commerce Commission’s review of Information Disclosure[1] is a natural starting point. For example, schedule 12b reports on forecast capacity. This could be evolved to reflect ‘constraints’ in a way that dovetails with the nature of the constraint(s) and factors affecting solutions.
- Meter data can support planning of distribution and transmission networks. In that light, an option is automated processes and standardised platforms/protocols for meter data management. Failing that, regulatory support to implement network monitoring and programs of rolling out network monitoring.

The Authority must be confident that any options/actions make an attributable impact on the decisions that are intended to be influenced. The initial focus should be on the decisions being made by market participants (including service definition) and the information that meaningfully informs or supports them. We support a cost benefit analysis including the setup and ongoing delivery costs and considers the timing and scale of decisions.

[1] A prioritised process for the Commission includes “a planned project of targeted amendments to the information disclosure regime”

Theme 2: Electricity supply standards

Key points

- A periodic review cycle (eg 5-yearly) of standards/regulations will ensure regulations and settings maintain pace with uptake, and don't require an event to require change.
- Review the +/-6% voltage limits to align with current state (wider limits)
- Broadening the concepts that originated in Part 6 from DG to load is appropriate in principle, but there are complications to achieve this that are beyond its scope

Summary responses

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

Yes.

Our experience is that solar DG inverters are often installed with inappropriate 'off the shelf' control settings. Supply impedance varies, and where it is high (say long service lines) voltage rise can be significant. The rise in voltage causes the installation voltage to reach the point where the inverter turns itself off (although it is apparent that many installers and owners have difficulty accepting this causal effect). Neither the installer nor owner understand the impact, or even the presence of the inverter control settings that could help with this ie Volt-VAR, Volt-Watt, Vmax.

Installers and sellers of these systems need an understanding of AS/NZS 4777.2, their inverter control modes, and the limitations of these modes where supply impedance is higher. Many of the connection and operation issues appear to stem originally from misunderstandings from DG and inverter installers. These include understandings about the impacts of Volt Var settings on energy metering due to reduced power factor, inverter control stability and loop impedance, connecting inverters to unloaded phases rather than loaded phases (which increases the neutral current), harmonics causing neighbouring consumer appliance maloperation, and the impact of long consumer service lines (beyond the point of supply).

We have also noticed some instances of consumer generation without back-feed protection (non-compliant with AS/NZS3000), which would be hazardous if we were not asking our field service contractors to test after isolating prior to applying temporary earths on upstream LV and HV circuits.

The high frequency harmonics produced by inverters have the potential to make an EDB's role more complex. We will watch this point as it continues to be researched internationally. The recommended limits for high frequency harmonics in the IEC standards require a loop impedance of only 3%, much lower than that needed for passively managing voltage within +/-6%.

Amongst some end use consumer segments, there has been limited apparent interest in DER options. For example, when some of the proponents of commercially driven network upgrades were offered simple DER options (such as special load control channels for irrigation schemes) that would have reduced their connection costs, they expressed little interest. These customers appear to place a higher value on ensuring they have control over when their electrical appliances can operate at critical times for their business.

We also observe

- Changes to the wholesale market would negate this if timing of the injection/charging cycles became unpredictable or did not correlate with network constraints.
- We need confidence in anti-islanding (safety) features and robust process to ensure all installations are notified and remain compliant. If not, and recognising the safety risk, the industry will have to rely on inefficient processes to isolate all connection points from the network before works can proceed.

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?

Yes. MBIE has a review of the Electricity (Safety) Regulations underway, with submissions invited that closed on 1 June. Included in this review was the currency of standards referred to in the regulations. We support the Authority considering all options equally and including the implementation timeframe as part of their assessment.

The nature of loads and generation is changing. There are numerous effects that straddle the Electricity (Safety) Regulations and the Participation Code. We support the Authority considering the interaction between the two. Below we have listed potential topics for consideration.

- Review terms around limits of voltage delivered, recognising the ability of modern appliances to tolerate wider voltage range than existed 50 years go. Whilst the above implies a basis to widen the allowable range of voltage variation, the "forgotten voltage drop" in customer's service mains may need to be recognised in this consideration. This is the 2.5% volt drop that electrical contractors used to allow for in the customer's service main (and still do) that used to be part of the +/-5% overall usable range of variation from the grid to the customer's switchboard. Evolution of regulation has meant the +/-6% became referenced to the Point of Supply instead (before the service main). This is pertinent to PV and DER because the inverter capacity is not linked to 'normal' household appliances and their use. Potentially large injection currents may be encountered compared to typical offtake (load) currents. Voltage rise then becomes a significant factor. For example, a typical residence will rarely draw more than 20A for a sustained period, but a large ESS, PV or EV could draw a sustained current over twice this level.
- The safety of installations with aged fittings, electrical switchboards and wiring. Many of the DG inverters are not capable of producing the level of fault current required to operate the conventional overcurrent subcircuit protective devices within a reasonably short period of time. If installations are to operate in island mode without grid connection, they will require residual current devices and probably upgraded overcurrent protection. This need to consider short circuit levels is covered by AS/NZS3000, but knowledge of it generally amongst installers appears to be lacking.
- Fire hazards associated with battery banks in consumer installations, particularly under over voltage situations (lightning or conductor clash).
- The requirements around what qualifies as a "short term fluctuation" of voltage, especially given the ability of electronic devices to rapidly vary input or output, or if switched capacitors are used upstream to balance the reactive power consumption of DG inverters with Volt VAR mode enabled.
- Requirements around management of harmonics need to be totally revisited in light of the transformation of the industry from predominantly resistive appliances to almost total electronic power supplies and large capacity inverters.
- Existing requirements for distributors to manage frequency at the point of supply.
- Requirements around how many phases an installation is configured for, and how it distributes load/injection across those phases. This recognises the potential for new technology to draw larger currents and have no inherent diversity (as attributable to random patterns of behaviour). DER and PV will respond to externalities (eg sun and market price fluctuations) and devices may respond in like manner at the same time.

For the longer term, research is currently happening internationally on the impacts of high frequency harmonics on consumer appliances and operation of distribution networks. This research will likely affect international standards.

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?

We support the Authority considering all options equally and including the implementation timeframe as part of their assessment.

We endorse inverter standardisation & certification, and support for international standards. Broadening the concepts that originated in Part 6 from solely DG to load also is appropriate in principle, but there are complications well beyond Part 6 or its scope.

Possible changes:

- Review the schedule of charges and timeframes to ensure they reflect current state. The complexity associated with (for example) a 1MW DG installation is substantially higher than with a 10kW unit. This also applies to the cost to process applications (system studies, network design, etc). We're keen for a review of the costs and principles to ensure the charges align with the costs incurred to ensure other customers are not affected.

- Clarify the definitions of hosting capacity and congestion and how they are to be applied. Congestion publications are ineffective in their current form, and the data and analytic capabilities in most EDBs don't yet support rigorous and accurate network wide evaluation. A practical and meaningful approach to present and maintain this information needs consideration.
- Confirmation is needed as to whether hosting capacity can be applied as a criterion for rejecting an application (which can often still be accommodated within the available network capacity at that time) eg can capacity be withheld in anticipation of an unknown number of *anticipated* future customers wanting an equal share? If not, then publishing hosting capacity is largely ineffective and pointless.
- There are indications of intent to broaden the concepts of Hosting Capacity (and Congestion possibly) to include off-take or consumption power flow, rather than solely covering injection or DG. (This would not be appropriate under Part 6 obviously unless its scope was changed) This is an appropriate concept in principle, but there are significant practical and administrative issues to address, and EDBs will vary in their readiness, and ability to meaningfully communicate such information eg, spatial visualisations; web portal interfaces). Unlike PV, load based congestion or hosting capacity analysis would require careful definition of the expected load profile and diversity (these aren't variable for PV). It would bring into the debate issues such as demand forecasting. This may be achievable for such appliances as EV chargers (provided capacity and control settings were pre-defined), but not general appliances and traditional load consumption.

A scheduled and periodic review (eg, every 5 years) of standards/regulations will ensure regulations and settings maintain pace with uptake, and don't require an event to require change. This would be similar in concept to the 7-yearly cycle of reviewing the input methodologies for EDBs.

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

Yes. The rules need to around both operating within and providing support for, voltage, frequency and power quality standards.

The design of the DER equipment should accommodate over-voltage situations (such as from lightning or vehicle accident causing a conductor clash). They should fail in a manner that minimises the risk of fire and minimises the risk of overvoltage to connected batteries or other appliances.

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

Protocols for appliances have been discussed for many years, though take-up of protocols or standardisation with appliances to support control is low, and for reasons outside the Authority's remit. The operation of the appliances will need to be mature, simple and seamless to consumers.

The fragmentation of entities in the supply industry means that standardisation of protocols will be complicated to implement.

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 support a review of standards (without a view to mandating). There's a balance to be found between over/under prescription, so what's equally important is to have a view on the costs/benefits in each instance. For example, the Authority will need to make the roles and requirements clear for addressing situations where a consumer's inverter doesn't comply with current standards.

EV charging is one area that warrants close monitoring and potential prescription. This is due to the consistent direction of government decarbonisation policy *and* the potential impact on demand. This will put a high value on the timing of charging patterns whether it be at times of peak consumer need, peak distribution demand, peak grid demand, or peak wholesale prices. Ideally EDBs should be allowed reasonable levels of control over this in tandem with pricing signals across the market. It will also tie in with identification and potential allocation of network reinforcement costs to causers.

Theme 3: Market settings for equal access

Key points

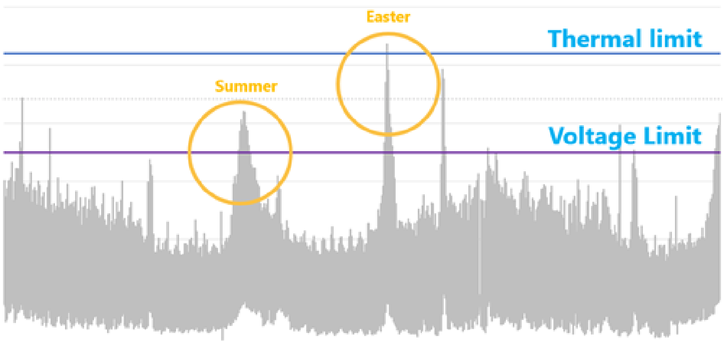
- The related party requirements on distributors are audited and transparent. They are the natural starting point for assessing any concerns about cost allocation and competitive procurement.
- Concerns about non-network options could start with looking at the nature and scale of non-network solutions considered in Asset Management Plans (an information disclosure requirement)
- Explore increased requirements on projects over a cost threshold eg $5m. This could involve reporting and/or market-testing.

Summary responses

Q.10 What flexibility services are you pursuing?

We are partway through a process seeking network support in the Coromandel region. This is an interesting project because it addresses technical, economic, and community issues in meeting reliability needs in the area. At the time of writing, an RFP has been issued and we look forward to responses. The timing for addressing this need is targeting December 2022.

When there's an influx of visitors to the region the network can struggle to meet peak demand if an outage occurs at the same time. This is mainly during long weekends, public holidays, and other times of the year when people take a break such as the Christmas/New Year holiday period and Easter. An FAQ about the project can be found here https://www.powerco.co.nz/about-us/your-energy-future/faq/



We have pursued several ROI opportunities in the past but unfortunately have not had responses from suppliers to allow us to pursue a non-network solution. There are a range of circumstantial factors for this, which boil down to whether the option is at the right time, right place, and right size for a supplier to participate.

To date we've only tried to procure large, single point services, to address nominal HV security constraints. The framework is probably too immature to meaningfully pursue mass market services, although our intent is. Trials are an excellent avenue for this, for example:

- DSR: Review ripple control strategy and application of existing flexible load eg, hot water control. Explore options for acquisition of more granular DSR flexible load and the communications and control platforms to manage these.
- EV: Strategy and industry participation in development for options around charger control architectures.
- DER: Strategy will evolve in tandem with the economic and market framework.

The IPAG view of a market where all flexibility services are 'carried out' by a trader. This also implies that the effect (value stream) to the EDB is in changes to 'bulk demand'. It's essential that any cost/benefit analysis captures the direct and indirect architecture costs if this concept is implemented for small scale flexibility in the mass market. As well as an additional communication step, which will potentially need to be a real time and reliable control signal, between the flexibility user and owner, EDBs will require high resolution (eg, ICP-specific) communication and control as the LV network will be where the initial effects will be felt of new technologies, not the bulk supply. This will involve addressing and investing in IT platforms and control mechanisms, web interfaces and real time communication standards. The administrative costs on new flexibility traders will be non-trivial and would represent a considerable shift in current trader capabilities.

Developing this market architecture is potentially achievable as the balance between implementation cost and effectiveness is assessed. Retailers are already offering real-time pricing reflecting the wholesale market, providing a trial at scale of the interface between customers, technology, and systems. It could be some time before real-time distribution prices are considered (or needed). So (retail) pricing signals will play a key role to influence behaviour, with distribution pricing an input to those (including the transmission price component) most likely via a TOU or LRMC (peak demand) component. These are intrinsically a coarser form of influence on consumer/appliance behaviour by the retailer, and indirectly the EDB, which is paired with a lower value as a result.

In this world, planning assumptions account for unpredictable behaviours and the potential unavailability of the resource eg, reasons like contractual, economic, alternative value, or physical outages. The result is that planning decisions reflect a more conservative estimate of response than 'perfect' (implicit in the Sapere analysis) though may still be optimal from the perspective of whole of system cost. Some factors influencing this are:

- the mismatch between revenue metering at arbitrary 30 minute periods and real-time operation which operates in real-time. The management of restoration of deployed flexibility at the edges of revenue periods can establish worse peaks or quality issues.
- Pricing being granular through time and location. This reflects that constraints are expected on the LV system first, where individual ICP flexibility services need to be targeted, where the value at stake is lower and transitory, and where the uncertainty can be considerably higher.

Ultimately, this discussion will be about finding a point to balance point network security (and ultimately customer experience) and market solutions/prices.

We also observe

- At the limit where all EDB expenditure was opex, a different regulatory/contracting regime would be required to incentivise investment (6.11). If a company only spends and recovers opex, then there will be no return to shareholder investment and hence no incentive to invest at all.
- Locking in a supplier to provide a distribution service go hand in hand. If an EDB cannot have certainty that their contracted requirements can be met eg, peak lopping when required) because another economic benefit has higher value elsewhere at the time, then they will not be able to rely on the DER solution and hence will be forced back to network investment, or owning the solution for their own purposes only. So, where a value-chain is applied, there must be sufficient certainty provided to EDBs that they will have their requirements met to meet Commerce Act requirements.
- We don't agree that distributors should be limited in how they deliver the network service (eg, being prohibited from owning or operating DER). What matters is the context of this outcome, and that it's in the long-term interests of consumers. These technologies may well be able to provide the most effective solution and best integrated with network operations. So a better approach is that there are measures in place to ensure that a fair and transparent process is adopted when sourcing (DER) solutions. We are keen to hear more about the merits of constraining network companies from adopting opportunities for lowest cost solutions.

Attachment 2 provides a useful reference point to contrast against Sapere's analysis. The Sapere analysis implicitly assumes DER can avoid distribution investment with perfect timing, perfect sizing, perfect costing, and with no loss of security/resilience. Attachment 2 provides examples of the realities of planning investments.

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

Yes.

The process we have been following for our Coromandel non-network solutions is:

- Situation monitoring, assessment of options (network and non-network)
- Planning and regulatory approval (or not) in line with regulatory cycles
- Updating assessment of options and situation
- An ROI to identify and shortlist a group of respondents
- A Request for Proposal (RFP) sent to shortlisted respondents (interactive to encourage innovation and value for money initiatives)
- Negotiation and due diligence stages

- Recommendations developed and approved

We followed the same process in 2019 for a project in Hinuera[2], though unfortunately were not able to pursue with any suppliers.

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

We think a pragmatic and cost-effective starting point is for market-testing be applied to projects over a cost threshold eg $5m. We suggested this in 2018 in response to the Commerce Commission's open letter consultation on the Wellington and Powerco CPP processes[3]. A copy of that material from our submission is below.

Summary of Powerco view on 'consideration of alternatives'
Applied pragmatically, the consideration of alternatives to traditional network solutions has the potential to promote efficient distribution network investment for the long-term interests of consumers. This would be achieved by enhancing consistency, transparency and predictability in planning processes.

Commission questions/topics for feedback	*Powerco Response*
Whether we should require market testing of major investments, and if supported then:	*Yes, we support the concept, if it is pragmatically applied. Creating a situation that results in excessive project delays and additional costs must be avoided.*
What is an appropriate threshold to require market testing (e.g. minimum dollar value of a project before it is required to be market tested);	*In the first instance we consider $5 million to be a suitable threshold. This level would provide substantial opportunity for market involvement while avoiding the excessive burden to EDBs that would arise from having to prepare numerous small project proposals. It is also the observed threshold used in the Australian Regulatory Investment Test for Distribution (RIT-D) process.*
What information and processes should be required for market testing; and	*The Australian Regulatory Investment Test for Distribution (RIT-D) process has proven to be a workable solution. The process required by Transpower also addresses the concerns but could involve excessive effort for relatively small projects.*
When the market testing should be conducted, with reference to the CPP application date.	*The requirement for market testing shouldn't be defined by a CPP application but by what is in the best interest of consumers. Therefore, market testing of appropriate projects should occur regardless of an EDB operating in a DPP or CPP environment. AMPs will provide visibility over projects that meet a trigger threshold and the associated indicative timing of projects. As some projects may not be scheduled until the latter stages of a CPP it is not feasible to test these prior to submission. It should become a 'BAU' process to test and integrate into DPP and CPP frameworks.*

Distributors are required to provide an overview of their non-network alternatives in Asset Management Plans. Relevant excerpts from Schedule D in the Information Disclosure requirements[4]:

D7 Lifecycle asset management planning (maintenance and renewal)	(b) where relevant, an overview of any network and non-network alternatives considered and the basis for selecting the preferred solution
D10 Identified programmes	(d) an overview of potential alternatives, including non-network alternatives, and the basis for selecting the preferred option with the information provided to be commensurate with the project's or programme's current status in the planning process

Market testing is an extension of the ComCom ID requirements in 11.8-11.12, which includes "…the potential for non-network solution to address network problems or constraints". Perhaps that would be an easy starting point for a 'bottom up' perspective of the scale/value of non-network alternatives. In our 2021 AMP, we comment on this in Chapter 6 (evolving network strategies), Chapter 15 (Growth and security) and Appendix 8 (Key projects). Of all these, Appendix 8 is useful as it summarises projects, cost, timing, and options analysis. Attachment 2 contains selected material from this part of our 2021 AMP.

The Commerce Commission published a review of asset management practices by electricity distributors in July 2021[5]. Although not a focus of that review, they note "*increasingly, good asset management involves*

[2] https://www.powerco.co.nz/news/rfi-transmission-alternatives-for-hinuera-area/
[3] https://comcom.govt.nz/__data/assets/pdf_file/0035/89585/Open-letter-seeking-feedback-on-Powerco-and-Wellington-Electricity-CPP-processes-3-July-2018.pdf
[4] https://comcom.govt.nz/regulated-industries/electricity-lines/information-disclosure-requirements-for-electricity-distributors/current-information-disclosure-requirements-for-electricity-distributors
[5] https://comcom.govt.nz/regulated-industries/electricity-lines/electricity-distributor-performance-and-data/review-of-asset-management-practices/potential-improvements-in-reporting-of-asset-management-practices-by-edbs

exploring alternatives to infrastructure investment and anticipating the future demands placed on the electricity system by the move towards decarbonisation. This is likely to be a feature of future reports." This would seem a suitable place to start.

If non-network solutions are more costly / less reliable than network solutions we're keen to explore with the Authority the how incentives for these solutions don't increase the cost / reduce reliability to consumers.

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

We encourage the Authority to focus on a definition of the services that competition is for, including non-financial attributes. This would allow the efficiency/competition of the current state to be quantified. At that point, the merits of options to encourage competitive procurement processes of the services can be assessed and tailored to the issues limiting it (if any).

An indirect option is increased visibility of network forecast investment and cost information. As noted earlier, achieving this requires regulatory support for EDBs to have more visibility and certainty of future customer demand (for both injection and consumption services) to ensure the network service is delivered safely and reliably. It also requires support for a significant uplift in EDB data and analytic capability and agreement on the key parameters and assumptions used to derive these market metrics for parties to invest against.

Theme 4: Operating agreements

Key points

- We're excited to be going to market for non-network options in the Coromandel area to ensure reliable electricity supply. The RFP has been issued to selected respondents and we look forward to considering their responses
- Contract development is a relatively small part of the process for engaging with 3rd parties to provide network support services. An inability for contracts to close shouldn't be confused with their being insufficient benefits to the parties. The objective is to ensure outcomes are in the long-term interests of consumers.
- There are benefits to allow the full process to run its course - and multiple times - before standardising terms. This allows all parties the maximum flexibility to explore and refine the contact over time to reflect the realities of purchaser and supplier requirements. This experience would then inform the nature of standardisation.
- To support this would be for contract parties to share the structure of contracts with commercially sensitive information removed.

Summary responses

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

No. Our challenge to date has been finding participants to negotiate with for services. We are keen to learn more about the concerns about negotiating position in the context of a company with a cost minimising objective and the requirements to meet quality standards. We support the Authority exploring the materiality of perceived issues (eg 7.10) outside of a consultation process and with a lens on the impact on costs to consumers.

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

Hasn't been a barrier to date.

Transaction costs can cover many issues – developing contracts is a part of the process and puzzle. As the Authority comments in 7.7, in the context of delivering the network service to consumes, the ability of suppliers to meet requirements (eg timing, reliability, accountability, second-order costs) can affect the ability to those suppliers to participate. This is conceptually the same as a potential supplier in the wholesale market not meeting asset performance obligations. The inability to deliver the service to requirements can be a barrier to entering a market. This isn't a transaction cost issue. We agree with the Authority's view in 7.15 about performance requirements being critical.

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

A standard might help eventually, we expect it would increase the costs to consumers if inadequately specified from rushing it. The Authority touches on one dimension of this in 7:20-7:21 in the comments about quality standards. These ultimately relate to consumer experience, and include power quality, planned and unplanned outages. The physical and financial aspects network support need to be thoroughly understood by all parties. We agree that suppliers of network support need to face consequences if they fail to perform. The incentives and accountability mechanisms need to lie on the flexibility service provider.

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

Responding to perceptions via a submission process is an inefficient way to resolve issues – we're keen to hear more from the Authority about what is informing their perceptions.

More importantly, the benefit of bespoke agreements is that they can maximise the value to consumers because they are tailored to their (network) needs and minimise their costs. We do support the Authority's focus on the costs imposed on distributors and suppliers from engaging in processes to provide network support. This is something the Commerce Commission will be interested in as well.

Theme 5: Capability and capacity

Key points

- We encourage the Authority to develop some clarity and measures on this topic before proceeding[6]
- Our 2021 Asset Management Plan outlines our plans to efficiently and effectively manage the impacts of decarbonisation on our network plans. This covers topics like the how and when to manage the physical impacts of climate change on resilience and how our role as a distribution system operator could evolve.
- Meaningful engagement with customers and stakeholders is vital to matching the network service to customer expectations. Examples of this can be found on https://powercodelivering.co.nz/project/[7].

Summary responses

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

Powerco's activities are described in our 2021 AMP[8] and via our project pages on powercodelivering.co.nz. We encourage the Authority staff to consider that material in response to this question given the Authority's views on what efficient and effective mean in practice.

Examples of activities include:

- Processing another RFI/RFP process in the Coromandel to provide an opportunity to potential providers of network support. This project involves engaging with the community and considering pricing impacts. https://www.powerco.co.nz/about-us/your-energy-future/
- Developing prototype models needed for a future with more dynamic network operation within tighter operational margins, and to make meaningful information more readily accessible.
- Installing Ineida LV monitors in our distribution transformers. We are also rolling out the Power Pilot system on many distribution transformers too. This helps us to assess and balance the loading of LV feeders, and load balance across phases, and lower order harmonics.
- The capability that the Eberle Power Quality meters at our zone substations provide is immense. They have been used to assess tap changer condition, secondary wiring issues in zone substations, harmonics phase imbalance problems. At first face, these seem more applicable to large solar PV farms, but we have used these to identify problems in industrial customer processes and appliances.
- An important initiative is our participation in the EPRI power quality research which comprises use of Power Quality as a predictive tool, data visualisation and analysis techniques, understanding predicting and modelling the effects of large scale DER integration, and improving customer service through PQ monitoring.

The EDB/retailer sponsored report "Efficiency Gains from EDB Amalgamation" by TDB as part of the Electricity Price Review[9] might be a useful reference point for the Authority to quantify the efficiency impacts of coordination.

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

The ENA has provided some examples, although we expect the Authority is familiar with all of these given.

In the context of distributed generation, there have been several EEA working groups, forums and conferences over several years – the most recent being the EEA's Masterclass on Grid Connected Solar Projects on 2 August 2021 at which staff have presented. In July 2018 the EEA released its "Guide for the Connection of Small-scale Inverter-based Distributed Generation" which resulted from a cross industry working group (Network Advisory Group) and work undertaken by the GREEN Grid project, funded jointly by MBIE, Transpower and the EEA.

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[6] For example, clarifying how capability and capacity are defined and assessed. Applying it to other entities may be insightful.
[7] Relevant topics for the Authority might include low voltage monitoring, heatmap data to inform renewal of conductors, crossarms and poles, and what's involved to meet Greytown's growth
[8] https://www.powerco.co.nz/media/2609/powerco-asset-management-plan-2021-p3.pdf
[9] https://www.tdb.co.nz/wp-content/uploads/2018/09/Efficiency-Gains-from-EDB-Amalgamation.pdf

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

The EDB/retailer sponsored report “Efficiency Gains from EDB Amalgamation“ by TDB as part of the Electricity Price Review[10] might be a useful reference point for the Authority to quantify the efficiency impacts of coordination.

Looking ahead, there are a number of longer-term issues jointly facing the transmission and distribution networks.

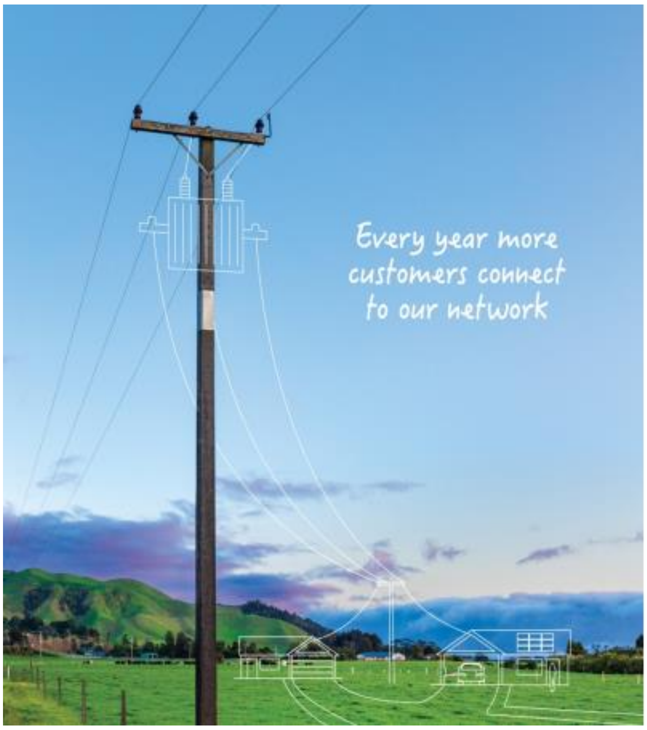
- *Inertia* One of the effects of electronic coupling of loads and generators is that any inherent inertia is isolated from the grid. The older generators provide synchronously coupled inertia ie, the grid has access to the rotational kinetic energy via the synchronous machine. Inertia is one of the key requirements for grid frequency stability. If no action is taken as new DG replaces older forms of generation, grid disturbance events will see increasing rate of change of frequency, reducing the available time to respond from seconds to fractions of a second. Further work needs to be done on inverter response, particularly in response to rate of change of frequency. The response would need to be well co-ordinated between inverters grid wide and scaled to ensure stability. An uncoordinated response could make things worse. Innovation and markets need to support a co-ordinated and stable response.
- *Governor control* Another effect of newer sources of generation, solar and wind, is that they do not have the ability to control power input to their prime mover. They deliver what the sun and wind dictate. One of the principles of grid frequency stability is real (kW) power balance. The older generators have governors that sense grid frequency and governors adjust the power input to the generator to increase or reduce the machine speed to stabilise the frequency. Governor tuned settings ensure the power increase/reduction work is shared. As newer forms of generation are added a decline in standard governor response will occur. A modified ancillary response will be needed. Some of this work is already underway with a review of the AUFLS system.

These two effects (reducing inertia and governor control) are being gradually eroded by the addition of solar and wind generation. Unattended decline in these areas will increase the likelihood of cascade grid wide outages as have been seen in South Australia and United Kingdom. There are also protection and fault current issues, reactive power and voltage management, ride through capability, and harmonic and supra-harmonic waveform distortion issues. Work is progressing internationally in all these areas.

[10] https://www.tdb.co.nz/wp-content/uploads/2018/09/Efficiency-Gains-from-EDB-Amalgamation.pdf

Attachment 1: Powerco submission to the Commerce Commission's open letter on energy network regulation

The material below is taken from our submission to the Commerce Commission's open letter on fit-for-purpose regulation of energy networks. It summarises the issues and considerations from a system level and with a customer focus – we implicitly treat the Electricity Authority and Commerce Commission regulatory regime as one, and with a common objective.



The future of networks is delivering value for

Consumers

Powerco supports the Commission's initiative to seek feedback about energy network regulation. There's no time like the present.

Our submission outlines priority issues that regulatory settings and their application will need to address across gas and electricity networks

There is a high degree of overlap. Providing an essential service in the face of policy uncertainty, evolving customer expectations, and technology change is a challenge for the regulator and the regulated

Clarity about the shared objective – ~~good~~ great outcomes for consumers – is the key. The onus is on all parties to demonstrate we're delivering it, and making sensible tradeoffs

Please contact Andrew Kerr (Andrew.kerr@powerco.co.nz) if you have any questions about our submission

Enabling customer choice

"The focus must be more on outcomes not process, on regulations that facilitate, not prescribe, and on how consumers consume, not on how businesses are organised "
Electricity Price Review, Final Report

"…in a way that does not compromise consumers receiving the energy services they demand, across reliable and resilient networks"
Commerce Commission, Open letter on network priorities

We support decarbonisation and therefore plan to avoid network constraints getting in the way of our customers. By doing this intelligently we should be able to avoid major network reinforcements. Currently, regulation does not support expenditure to enable open access networks the benefit to consumers is not immediate or certain. Spending to support customers' future needs *now* will not lower costs to customers *now*, nor will it improve the quality of service to customers *now*.

Emerging issues

- The reliance on electricity will increase as the scale and diversity of use increases: working from home, charging transport at home, or maybe connecting PV/battery at home. Emerging issue: investing ahead of the demand for open network capability to enable customer technology choices.
- Maintenance of the network with high quantities of distributed generation at customer level creates safety/cost issues when maintaining nearby lines. Aging customer service lines exacerbates the issue.
- Evolving network pricing and planning is contingent on access to detailed consumption data, along with establishment of systems and processes. Uncertain and fragmented access to data access will delay these initiatives, and the associated benefits to consumers.
- One of the advantages of having a shared gas or electricity network is the fixed costs are shared across a large customer base. If policy settings reduce connections, those who are left are the ones that less likely to be able to pay higher costs.

Possible regulatory considerations

- Review the approach to certainty to approve expenditure (IMs and reset decision processes) eg 'no regrets' activities to support DER integration
- Review quality measures for customers eg transition from simple duration and event measures to a 'value'-based measure that reflects customer needs
- Review regulatory approach to customer service lines in light of increased electrification and penetration of technology which can export to the network.
- Provide compliance guidelines on breaches of requirements so consumers and distributors have clarity about actions, outcomes, and consequences
- Consider regulatory settings that minimise the extent of future price shocks driven by legislated policy settings eg net-zero by 2050

Planning to meet policy outcomes

"Signalling longer term policy well in advance will support both public and private investment decisions in line with target outcomes"
CCC draft advice

"Climate change exists beyond the four-year horizon of the Public Finance Act. [We're] working on a solution for that"
James Shaw

The approach to regulation of electricity and gas infrastructure will need to align with the objectives and timeframes of the Government and the Climate Change Commission *and* accommodate the uncertainty about when, where, and the scale of change.

Emerging issues

- The Climate Change Commission's advice and budgets will drive step changes to the scale of demand for electricity. This will increase the demands on infrastructure and systems required to connect and transport it.
- An expectation that distributors can deliver just-in-time investment is mismatched with the practicalities of delivering infrastructure. It risks a just-too-late approach to planning (higher cost, more disruptions to implement).
- New Zealand's emission budgets and associated policies extend well beyond the 5-year regulatory approval cycle for regulated entities. The pace and scale of change modelled by the Climate Change Commission will challenge the current regulatory approach which relies on the past to inform the future and sets a high threshold for deviating from it

Possible regulatory considerations

- Review the interaction between climate change objectives/policies and the purpose of promoting "…the long-term benefit of consumers" in the Commerce Act. Do climate objectives need to be explicitly recognised?
- Explore how the IMs and DPP reset align with EDBs being tasked with 'planning to meet policy objectives and outcomes' - these will be a key driver of our planning requirements
- Review how regulatory allowances accommodate forward-looking or new requirements that may not align with historic outcomes eg cyber-security, mitigating physical and transitional climate change risks, emission offsets, network monitoring, changes to supplier costs from social and climate policy, data acquisition from meter providers/retailers
- Tailoring allowances to accommodate the individual needs of distributors given non-uniform impacts of climate change policy and initiatives.
- Consider how policy uncertainty can be accounted for in director-certified forecasts

Innovation

"The phase-out of natural gas from our energy system is a complex issue and the Commission has made clear that it has a use-by-date in New Zealand. …our current gas distribution infrastructure provides many opportunities for alternative lower emissions fuels to be used, including biogas and hydrogen. "
Megan Woods

The Commerce Commission should implement default price-quality regulations in a way that encourages innovation among distributors. An example is using demand-side management tools that encourage consumers to use less power, or use it at off-peak times, to alleviate network congestion
Electricity Price Review, Final Report

Innovation is an ill-defined term. It can be more helpful to focus on the types of decisions and opportunities that regulated companies are facing now and/or might need to make in the future.

Emerging issues

- Gas networks are facing the opportunity to repurpose from natural gas to other gasses at the same time as managing the impact of policy decisions about natural gas use.
- Increased use of electricity for vehicle transport, process heat, or working from home will increase the reliance on the electricity system over and above the status quo. Distributors will need to respond to this, whether it be investment in systems or in the network to manage increased resiliency needs (because the impacts of disruption will be magnified).
- Powerco's application for network evolution allowances were not approved by the Commission in its CPP determination. The market and policy environment has evolved significantly since then. There is perhaps more certainty now about the value, or indeed the need, for these initiatives, especially for networks that have scale.

Possible regulatory considerations

- Consider a sectoral definition or principle to guide regulatory treatment and approach to risk, funding, and outcomes
- Innovation allowances for gas networks to play their part in supporting policy outcomes related to low-carbon gasses.
- Review the approach for innovation allowances across EDBs to ensure there's no barrier to testing approaches to deliver to the Government's policy outcomes and minimises duplication
- Review arrangements and capability to obtain and maintain consumption data to support efficient pricing and planning in the face of technology changes
- Review the interaction of ring-fencing obligations with other mechanisms to ensure the 'sum of the parts' promotes competition and innovation

Incentives that reward the right decisions and outcomes … and are workable too

"Connecting tens of thousands of DERs to a network may fundamentally alter the way the network has to operate and may greatly increase investment requirements. It is important that preparatory work starts soon so that networks are well prepared for the potential influx of DERs."
Te Waihanga, He Tūāpapa ki te ora

"There are long lead times in energy infrastructure investment, and parties are making decisions right now that will impact the sector for decades to come. "
Electricity Authority

The package of regulatory settings needs to be examined to ensure distributors are making good investment decisions –probably means a balance between transparency of process and targeted financial incentives on the things that really matter

Emerging issues

- The desire for investment from policy makers is balanced by the uncertainty faced by investors – not just market and technology, but also Government policy intervention and treatment of key inputs to cost and revenue setting eg CPI. Asset lives are typically far longer than the economic horizon, so the only way to manage risk is via halting investment…contrary customer want
- The incentive scheme (IRIS) appears to create confusion rather than resolve it. For example, the Aurora CPP decision was complicated by including IRIS. And it doesn't apply to all distributors given some are exempt from regulation.
- Decisions from other regulators or policy makers can be NPV positive at a system-wide level for consumers, but may not have been considered when allowances were set or will be set. This can impact the quality of forecasts.
- Decarbonisation of commercial and industrial load can bring forward planned investments. Yet these costs are included in the incentive regime and revenue isn't recognised within the period.

Possible regulatory considerations

- Include an accelerated depreciation facility for gas networks to improve alignment between economic life and utilisation (as seen in Australia)
- A pragmatic approach for reopeners for material event, policy or regulatory driven costs for many/all networks
- Review approach to treatment of CPI to ensure symmetric outcomes in the long-run
- Review WACC settings to ensure assumptions workable and appropriate to NZ policy and market contexts for gas and electricity networks
- Review incentive mechanism to ensure opex/capex tradeoffs are meaningful and workable eg exclude customer-reactive capex to avoid creating arbitrary winners and losers from forecast errors, merit of a totex regime

Attachment 2: Selected material from Powerco 2021 AMP

Powerco's 2021 Asset Management Plan[11] contains 64 pages of information about major fleet management and network development projects, including consideration of non-network solutions. We have included the first few pages of this material below to illustrate the content and complexity and context of investments.

What is worth highlighting in the context of the Authority's paper are the categories of expenditure (growth is one of these), the practical complexities driving investment, and how uncertainty is treated. This provides a useful reference point to contrast against Sapere's analysis which implicitly assumes DER can avoid distribution investment with perfect timing, perfect sizing, perfect costing, and with no loss of security/resilience.

APPENDIX 8 KEY PROJECTS

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A8.1 APPENDIX OVERVIEW

This appendix provides additional details for planned projects outlined in our Fleet Management and Network Development plans.

The appendix describes the constraints, technical options and preferred solution for the Growth and Security projects outlined in Chapter 15. In general, only projects scheduled to commence in the next five years are listed unless they are of significance to the overall zone substation or area plan. Towards the later part of the planning period, project needs and solutions are less certain. This is because of the volatility of the growth forecasts and impact of future technologies on demand. The listed 'future projects' are continuously reviewed against future demand forecasting. Available options, cost estimates and preferred solutions are expected to change, be refined over time and become firmer as the projects move closer to commencement.

This appendix also includes a description of our larger renewal projects. Only zone substation and subtransmission projects with expected costs exceeding $500,000 have been included and, again, only those that are scheduled to commence in the next five years. Like Growth and Security projects, our renewal projects are continuously reviewed against updated condition assessment and asset health information, and plans updated and adjusted.

The Electricity Distribution Information Disclosure Determination requires us to disclose our forecast expenditures under specific categories. The categories mostly used in this section include:

GRO - System Growth

ARR - Asset Replacement and Renewal

QoS - Quality of Supply

ORS - Other Reliability, Safety and Environment

A8.2 ORS – OTHER RELIABILITY, SAFETY AND ENVIRONMENTCOROMANDEL

A8.2.1 SUBTRANSMISSION NETWORK PROJECTS

A8.2.1.1 NEW KAIMARAMA 66KV SWITCHING STATION

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
KAIMARAMA GIS SWITCHING STATION	GRO	$9,720	2021-2023

Network issue

The combined 2019 peak demand on the Coromandel, Whitianga and Tairua substations was ≈30MVA. During an outage of the 66kV line between Kopu and Tairua, the section of 66kV line between Kaimarama and Whitianga is often overloaded during peak demand conditions. During an outage of either 66kV circuit from Kopu, the remaining network is voltage constrained at peak demand. These three substations therefore do not meet our Security of Supply Standard, which requires a no break N-1 supply (security class AAA).

In addition to the above constraints, the subtransmission network supplying the Coromandel, Whitianga and Tairua substations has a history of poor reliability because of the long overhead lines that cross rugged and exposed terrain, coupled with the existing meshed configuration and tee connections. The Coromandel area's subtransmission network is our worst performing area in terms of System Average Interruption Duration Index (SAIDI).

There is a particular issue with the Coromandel substation, supplied via a 66kV line that tees off the Tairua-Whitianga 66kV line. The implementation of a robust electrical protection system on this three-terminal network has been found to be difficult. Protection systems have been upgraded on the subtransmission circuits to allow the 66kV ring to be operated permanently closed. Future upgrades will involve high speed communication systems to enable fast inter-trip schemes to operate on the subtransmission network.

Options

1. Re-conductor existing Kaimarama-Whitianga 66kV lines.
2. New Kaimarama-Whitianga 66kV overhead line.
3. New Kaimarama-Whitianga 66kV underground cable.
4. New Kaimarama-Whitianga 110kV overhead line (initially operated at 66kV).
5. New Kaimarama-Whitianga 110kV underground cable (initially operated at 66kV).
6. Kaimarama 110kV-capable switching station.

Preferred option

Currently, the preferred option is the installation of a new Kaimarama 110kV-capable switching station (option 6 above), based on the use of indoor gas insulated switchgear, enclosed in a switchroom designed to blend in with the environment. The landowners have signed an option agreement contract that secures Powerco the right to purchase the land to build the gas insulated switchgear switching station. The project is at the detailed design stage.

[11] https://www.powerco.co.nz/media/2609/powerco-asset-management-plan-2021-p3.pdf

A8.2.1.2 KOPU-TAIRUA 66KV LINE UPGRADE

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
KOPU-TAIRUA LINE UPGRADE	GRO	$14,176	2021-2023

Network issue

The combined 2020 peak demand on the Coromandel, Whitianga and Tairua substations was ≈30MVA. During an outage anywhere on the long 66kV line from Kopu GXP (grid exit point) through to Whitianga, the line between Kopu and Tairua does not have sufficient capacity to supply all three substations during peak loading conditions. The 66kV network would also experience voltage constraints at its extremities (ie Coromandel substation). These three substations therefore do not meet our Security of Supply Standard, which requires a no break N-1 supply (security class AAA) regarding the subtransmission network.

Options

1. Re-conductor existing Kopu-Tairua 66kV line.
2. Duplex the existing Kopu-Tairua 66kV line.
3. Build a second Kopu-Tairua 66kV line.
4. Alternative non-network solution (Project CORE) – distributed generation (DG).

Preferred option

Option 1, to re-conductor the existing Kopu-Tairua 66kV line, is preferred. However, the consenting and property issues of a new line are prohibitive through this area of sensitive landscapes and difficult physical access.

Moving to a non-standard (for the distribution industry) duplex construction represents high risk – conductor fittings are scarce and the technology largely unproven in post or pin type construction. In addition to the line upgrade, 66kV reactive support will be needed to address the voltage constraints eventually. This could occur as a separate project following the line upgrade.

Detailed design and engineers' estimates for option 1 have been completed and indicate that project cost is going to be much higher than the original estimated costs calculated a few years ago. Powerco is investigating DG as a non-network solution (option 4). Option 1 is still being worked on in parallel while the feasibility work is carried out for option 4.

A8.2.1.3 NEW KOPU-KAUAERANGA 110KV-CAPABLE LINE

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
KOPU-KAUAERANGA 110kV LINE	GRO	$9,900	2028-2030

Network issue

During 2019, the total load on the Thames substation was ≈13.3MW. The substation supplies medium-demand customers, including A and G Price ≈1.6MW, Thames Toyota and Goldfields shopping centre. Under normal operating conditions the supply to Thames is via a single 66kV circuit. If there is a fault on the normal Thames supply a second overhead 66kV supply line can be switched in. However, the second circuit is shared with the Coromandel/Whitianga/Tairua substations and the shared section (≈5km of Raccoon conductor between Kopu and Parawai) would be overloaded during peak loading conditions. Therefore, the existing supply network to Thames does not meet the requirements of our Security of Supply Standard, which recommends a no break N-1 supply network with a security class of AAA. The section of overhead line between Parawai and Kauaeranga is overloaded when supplying Whitianga, Coromandel and Tairua in the event of a Kopu-Tairua outage.

In addition, the subtransmission network in the Coromandel area has a long history of poor performance because of the long overhead lines that cross rugged terrain. This is compounded by the meshed configuration that involves several 66kV tee connections. The simplification of the existing network is expected to deliver significant benefits to customers in the Coromandel area.

Options

5. New 110kV-capable line from Kopu GXP to Kauaeranga initially operated at 66kV.
6. Thermal upgrade of the existing Kopu-Kauaeranga 66kV line.
7. Re-conductor the existing Kopu-Kauaeranga 66kV line.

Preferred option

The preferred option is to construct a new ≈8km, 110kV capable, overhead line from Kopu GXP to Kauaeranga (option 1 above). This is the only option that addresses the performance issues related to the meshed configuration and manually switched backup circuits, by separating the subtransmission for Thames from that for the peninsula (Coromandel, Whitianga and Tairua). The new line would initially be operated at 66kV but be 110kV-capable to align with our future plans to supply the proposed Kaimarama switching station, from Kopu, via an 110kV supply line.

The proposed line route has been designated, and agreements are in place with most landowners. However, one block of land is subject to Treaty of Waitangi settlement claims and is likely to delay the project's construction start date. As an interim measure, to enable the deferral of the new line, the section of Mink conductor between Parawai and Kauaeranga has been re-conductored and the Kopu-Parawai section of Racoon thermally upgraded.

A8.2.1.4 WHENUAKITE 66/11KV SUBSTATION

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
WHENUAKITE 66/11kV SUBSTATION	GRO	$13,820	2021-2023

Network issue

During 2019, the peak loading level on the Whitianga 66/11kV substation was 17.5MVA, which exceeds the existing (N-1) substation capacity. The 11kV backfeed from the adjacent 66/11kV substations is small, and the Whitianga substation does not meet Powerco's Security of Supply Standard which, given the size of peak demand, requires the substation to provide a no break N-1 supply.

At present, several 11kV feeders at Whitianga substation have an installation control point (ICP) count well in excess of the targeted maximum for their respective security levels. The constant growth in Whitianga requires a combination of more feeders and zone substation capacity.

The Cooks Beach/Hahei area is fed from the already constrained Whitianga substation and feeders. The feeders that supply Cooks Beach/Hahei have inherent performance and reliability issues, which cannot be rectified easily, and supply quality on the feeders into this area is poor.

Options

1. Upgrade Whitianga substation and construct two new 11kV feeders.
2. New Whenuakite substation (in and out 66kV configuration).
3. New Whenuakite substation (66kV tee connection).
4. New Whenuakite substation (66kV switching station).

Preferred option

Currently, the preferred option is to build a new Whenuakite substation, supplied via a new 66kV double circuit line that connects into the Tairua-Whitianga circuit using an in-and-out configuration (option 2 above). Detail design of option 2 is under way. This option will reduce the existing Whitianga substation feeder ICP count and shorten the length of the feeders and improve feeder performance. Future load growth in the region can be accommodated with the preferred option. Installing additional 11kV feeders from Whitianga substation, instead of a new Whenuakite substation, would face considerable consenting and construction challenges, and would not address load constraints at Whitianga itself. A tee connection for the proposed Whenuakite substation (option 3) would exacerbate the existing protection and operational constraints on the 66kV. Obtaining property and consents for both a substation and a switching station (option 4) would considerably add to costs and project complexity.

A8.2.1.5 MATARANGI 66/11KV SUBSTATION

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
MATARANGI 66/11kV SUBSTATION	GRO	$10,000	2021-2023

Network issue

As noted for the Whenuakite constraints above, the 11kV feeders from Whitianga substation are long and heavily loaded, with ICP counts and feeder lengths exceeding our recommended standards. This impacts on reliability as more customers are affected and for a greater number of outages per year. Strong growth has been sustained in the past decade and is predicted to continue because of the area's continued popularity for holiday accommodation. Backfeed capacity on the 11kV is particularly constrained and secure capacity at Whitianga substation is exceeded.

The coastal townships to the north of Whitianga, including Matarangi and Kuaotunu, are supplied by two 11kV feeders as follows:

- Owera Rd feeder: A rural overhead line feeder that follows a path north-east from the Whitianga substation to Matarangi, a distance of ≈15km. During peak network loading periods (≈3.5MVA in 2019) a significant portion of the electrical load is at the end of this feeder and it is equipped with a voltage regulator and two pole-mounted capacitor banks to elevate delivery voltages.
- Kuaotunu feeder: Passes through the Whitianga township supplying some urban customer load before heading north-west to Kuaotunu. The 2019 peak load on the feeder was ≈2MVA.

The loads on the above two, long 11kV feeders are projected to continue to increase with ~300 lots proposed at Matarangi and ~80 lots approved at Opito Bay. The combined peak load of ≈5.5MVA on the two feeders cannot be supplied by a single feeder (ie during an outage of the other feeder).

Options

1. Upgrade Whitianga substation and construct two new 11kV feeders.
2. New Matarangi substation supplied via a 66kV spur line.
3. Install an 11/22kV transformer and upgrade the existing 11kV network to 22kV.
4. Alternative non-network solution (Project CORE) – DG

Preferred option

The preferred solution is a new Matarangi substation supplied from a new 66kV line from Whitianga substation (option 2 above). This option also provides for a staged implementation where the new 66kV line could initially be operated at 11kV and upgraded later when the substation was needed.

Upgrading feeders from 11kV to 22kV (option 3) has been looked at as a coordinated strategy for the Coromandel, but costs remain too high considering the infrastructure (distribution transformers, insulators, lines, cables, tap-changers) that would need to be upgraded or replaced.

As for the Whenuakite project, constructing additional 11kV feeders out of Whitianga substation does not address the constraints on Whitianga substation itself.

Option 4 is also being investigated as part of Project CORE to install DG to test whether the solution is feasible and economical. This option will relieve thermal constraints on the 11kV feeders when required.

A8.2.2 ZONE SUBSTATION PROJECTS

A8.2.2.1 BACKUP SUPPLY TO KEREPEHI SUBSTATION

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
KEREPEHI REFURBISH 11kV SWITCHBOARD	ARR	$700	2026
KEREPEHI 66kV OUTDOOR CIRCUIT BREAKER REPLACEMENT	ARR	$140	2024
BACKUP SUPPLY TO KEREPEHI SUBSTATION	GRO	$5,000	2022-2024

Network issue

The Kerepehi substation is supplied via a single 66kV circuit from Kopu GXP. During an outage of this circuit, there is limited 11kV backfeed from nearby substations to provide backup. This backfeed is not sufficient to provide the required security to Kerepehi substation.

Options

1. Reinstate an old 50kV line between Kerepehi and Paeroa energising it at 33kV and install a 33/11kV transformer at Kerepehi to back up the substation.
2. Construct a second 66kV circuit from Kopu.
3. Improve the distribution network and increase the 11kV backfeed capability.
4. Install backup distribution generation.

Preferred option

The current preferred solution is option 4, to install backup DG at Kerepehi substation. This will offer backup, peak lopping ability, and be future-proofed to provide grid scale microgrid capabilities. The original preferred option 1, to reinstate the 33kV line between Kerepehi and Paeroa in its current form will not be completed within the period because of access and consenting challenges, which will also add considerable cost to the project.

Powerco is undertaking a concept design option involving renewal or replacement of the indoor 11kV switchgear, and DG.

Fleet issue

The existing 11kV switchboard at Kerepehi substation does not meet modern arc flash standards and has oil quenched circuit breakers. The Kerepehi switchroom has recently been seismically strengthened. The outdoor 66kV circuit breaker is unreliable and is scheduled for replacement.

Options

1. Refurbish the existing Kerepehi 11kV switchboard including arc flash protection, arc flash doors and end panels. Replace the 66KV outdoor circuit breaker.
2. Install a new 11kV switchboard in the existing Kerepehi switchroom. Replace the 66kV outdoor circuit breaker.

Preferred option

The preferred option is to refurbish the existing Kerepehi 11kV switchboard and replace the 66kV outdoor circuit breaker.

A8.2.2.2 MATATOKI SUBSTATION

PROJECTS	DRIVER	COST ($000)	TIMING (FY)
MATATOKI SEISMIC STRENGTHENING	ARR	$200	2024
MATATOKI REFURBISH 11kV SWITCHBOARD	ARR	$533	2024-2025
MATATOKI REPLACE 66kV CIRCUIT BREAKERS	ARR	$200	2026-2027
MATATOKI SECOND TRANSFORMER	GRO	$2,130	2029-2031

Network issue

Matatoki is supplied from a single 7.5MVA 66/11kV transformer. An outage on this transformer causes loss of supply to the substation. Existing 11kV backfeed capacity is insufficient to support the maximum demand load. This means that the substation does not meet Powerco's Security of Supply Standard.

Options

1. Install a second transformer at Matatoki substation.
2. Increase 11kV backfeed capacity to Matatoki.

Preferred option

The preferred solution is option 1, which is to install a second 7.5MVA 66/11kV transformer at Matatoki substation. This will provide backup to the existing unit. Option 2, to further increase 11kV backfeed capacity, will involve substantial 11kV infrastructure investment and is not economically attractive.

Fleet issue

The Matatoki 11kV switchroom has a seismic strength of 35% New Building Standard (NBS), below the 67% NBS value required for seismic compliance. The existing 11kV switchboard at Matatoki substation does not meet modern arc flash standards, has oil quenched circuit breakers and electromechanical relays.