POWERCO

19 July 2023

Via email IM.Review@comcom.govt.nz

Tēnā koe,

Ensure the IMs have more than the minimum when it comes to flexibility and incentives … build the capability set ahead of need

The 2023 Input Methodologies decision will guide how gas and electricity networks invest and operate to the early 2030s – potentially to 2035 for electricity networks. Powerco is one of Aotearoa's largest gas and electricity distributors, supplying around 352,000 (electricity) and 113,000 (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. We are developing our network plans to reflect a range of uncertainties as we, and our customers, look to adapt to and mitigate the impacts of climate change. Similarly, **we urge the Commission to take a long-term view about the nature and pace of decarbonisation when setting incentive and uncertainty mechanisms so that we can meet the needs of our customers in their timeframes**. While we don't know how the future will play out, we do not expect it to be steady state for the periods the IMs will apply to. We back ourselves to direct our investment wisely and meet customer needs in a timely manner – the challenge is for economic regulation to match it.

We generally support the Commission's conclusion that the IMs are "…fit for purpose though there are areas for improvement". Our summary views on key topics are:

Dealing with changes and uncertainty	Refinements to the re-opener mechanisms will improve customer outcomes: • **Include requirements for the Commission** to outline its approach to processing applications (including timing) to provide certainty to customers and suppliers. • **Support 'Large Connection Contract' (LCC) mechanism**. To boost its effectiveness, we suggest reducing the thresholds and including a financial threshold to align with reopener thresholds. • **Recommend** contingent and/or use-it-or-lose-it allowances be kept in the Commission's toolkit should they be an appropriate mechanism to address unforeseen circumstances that could occur at future resets

Financing and incentivising efficient investment	• **Support** the refinements to electricity revenue cap washups, though it can be made simpler to better to better handle within period events. • **Support** the Commission's decisions on indexation for EDBs and Transpower as it shifts cost recovery to the future when the consensus is that electricity demand will be higher. • **Support** the decisions to account for actual inflation when determining revenue and incentive amounts. • **Support** the changes to the innovation project allowance as it creates a more favourable environment for the adoption and implementation of non-traditional and innovative solutions. • **Recommend** the Commission reconsider it's 'no change' decisions about indexation and form of control for gas pipeline businesses
Cost of capital	• **Support** a review of WACC settings to align with new and ongoing investment over a crucial period in the transition to a lower carbon energy system. • **Recommend** that a wider range of costs to society and consumers are considered, rather than just outages, when setting the optimal WACC percentile. • **Maintain** an uplift on the WACC percentile at the 67th percentile for electricity networks, to maintain regulatory stability and preserve incentives to invest. • **Maintain** an uplift of WACC percentile at 67th percentile for gas networks to support positive reliability outcomes for customers and recognise the social and environmental costs of under-investment.

We have structured our submission to align with the Commission's topic papers. We have commented on a subset of provisions, whether changed, amended, or unchanged. This is primarily due to the scale of IM changes and the (short) 5-week timeframe to digest the material and prepare submissions. There are several decisions from the Commission that will benefit from industry engagement and/or more demonstration material before the IMs are finalised. If this is not possible, an alternative is to plan for amendments before their application in the next gas and electricity resets.

If you have any questions regarding this submission or would like to talk further on the points we have raised, please contact Andrew Kerr (Andrew.kerr@powerco.co.nz).

Nāku noa, nā,

Andrew Kerr
Head of Policy, Regulation, and Markets
POWERCO

Topic 1: Financing and incentivising expenditure during the energy transition

For this IM review the Commission grouped issues into three topics, each with a 'topic paper' that explains the draft decisions and reasoning on IM decisions relevant to the topic.
1 Financing and incentivising efficient expenditure during the energy transition
2 Cost of capital
3 CPPs and in-period adjustments
This section contains our responses to topic 1: Financing and incentivising efficient expenditure during the energy transition.

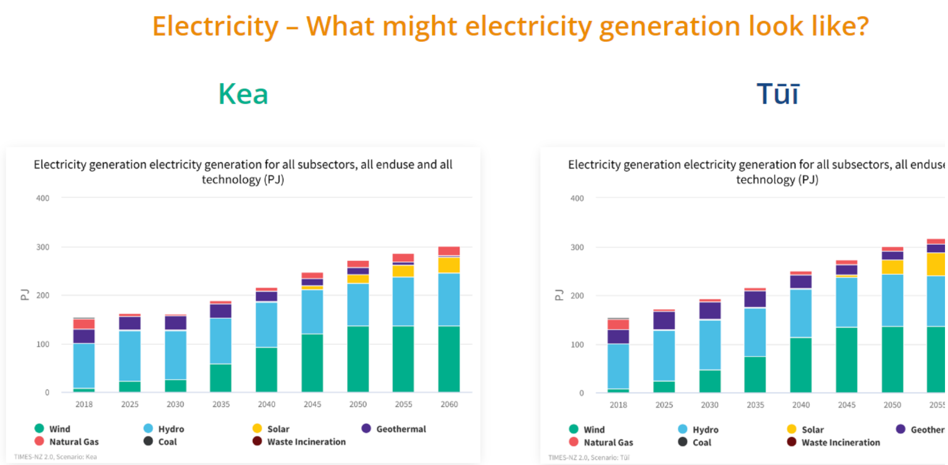
Decision	Powerco response
Introduce a revenue wash-up for inflation in the first year of a regulatory period	Support the proposed first-year revenue wash-up for inflation. Powerco supports the draft decision to wash-up the difference between forecast and actual CPI in the first year of each regulatory period, which will align the treatment of inflation across the entire regulatory period. This will avoid potential gains and losses which may arise due to significant inflation volatility in year 1 of a regulatory period. It also removes one source of additional risk when transitioning between DPPs and CPPs.
Changes proposed to revenue wash-up draw down	Support the simplification of the wash-up mechanism, however regulatory certainty must be prioritised. Wash-up draw down We **support** proposals to simplify the wash-up drawdown, reduce the complexity of the IM clauses which give effect to the wash-up mechanisms, and include some elements of the wash-up in PQ determinations. Without more information about the PQ determination clauses, it is difficult to fully understand how the proposed wash-up account will apply in practice. This is contrary to the regulatory certainty objective of the IMs. We **recommend** that the final decision include a demonstration model of the wash-up, and examples of the PQ determination clauses that will supplement the IMs to give effect to the wash-up. This will improve regulatory certainty. Pace of draw down The draft decision proposes that EDBs will be able to choose when to draw down a wash-up balance, subject to the revenue cap and revenue smoothing limits. Powerco **supports** the introduction of this mechanism which will provide flexibility in managing prices, revenues and cashflows within the regulatory limits. We **do not support** the proposal for the Commission to specify annual wash-up amounts to be drawn down by each EDB in a PQ determination. The draft decision paper does not explain *why* this has been proposed or how the Commission will determine the amounts to be drawn down. Accordingly, this is not consistent with promoting regulatory certainty of the 52A purpose. EDBs are best placed to manage pricing and funding decisions within their regulatory limits within a regulatory period. A recent customer survey on pricing showed customers prefer smooth changes (41%) over step-changes (29%), with remaining 30% of customers sampled having no preference or unsure. Fewer constraints will allow EDBs to better manage price impacts between and

Decision	Powerco response
	over multiple years, including accounting for any interactions with situations and events that impact revenues within the regulatory period e.g., reopening the price path. Inter-period transitions Powerco **supports** the draft decision to improve certainty about the transition of revenue cap wash-up balances between regulatory periods. This will improve regulatory certainty. We are expecting a significant wash-up balance at the end of DPP3 due to deferred revenue recovery resulting from our decisions to manage the extent of price changes within regulatory period, along with inflation wash-ups. Certainty about the treatment of these will support development of our pricing for customers who take a keen interest in our estimates of future prices. We acknowledge and support the intent of the transitional revenue accrual term to be introduced to the IMs to carry forward the DPP3 wash-up balance to DPP4. It is essential that the transitional amounts are available for draw down from year 1 of DPP4 - our reading of the draft determination suggests that it won't be available until year 3. The ENA submission makes several technical drafting suggestions in this respect.
Change secondary revenue limit to exclude recovery of pass-through costs and reclassify transmission recoverable costs as pass-through costs	Support the exclusion of pass-through costs, including transmission costs from the secondary revenue limit. We support the proposals for forecast pass-through costs to be recovered in the year incurred, with a wash-up for forecasting error in the following year. We also support categorising transmission charges as pass through costs. Pass through costs are outside our control as they reflect costs which are not directly incurred by us. We agree that transmission charge volatility is best addressed during the IPP and TPM regulatory processes, not EDB revenue cap limits.
Changes to secondary revenue limit	Powerco **supports** the draft decision to change the design of the secondary revenue control limit to allow for alternatives to an annual percentage limit. The IMs could be strengthened by including a description of the factors the Commission will consider when determining the smoothing limit to improve regulatory certainty. We expect these would include the impact on customer prices, the impact on EDB cashflows, and the ability of an EDB to recover its reasonable costs consistent with the services supplied during a regulatory period.
Change the timing of the CPI wash-up from a two-year lag to a one-year ahead forecast	We **support** the draft decision to update forecast allowable revenue for a year ahead inflation forecast with a residual wash-up for actual inflation in the following year. This proposal should help to avoid significant wash-up amounts, and deferred revenue recovery, experienced during DPP3 due to unexpectedly high inflation. This proposal also applies to other regulated income, which we support.
Introduce a cost of debt washup for inflation	We **support** this in principle. Before implementing this in the final decision, the Commission must comprehensively demonstrate the mechanism works, including how it will interact with the other revenue washup mechanisms.
Introduce a new connections	The proposed connections wash-up could go further.

Decision	Powerco response
volume wash-up mechanism for an EDB CPP, but not a DPP	There is increasing uncertainty about the demand for new and upgraded connections to our electricity network, and for this reason we have previously supported excluding connection capex from IRIS. This has not been reflected in the draft decision. A connection capex wash-up has been introduced for CPPs but not for DPPs. This wash-up should also be extended to DPPs, as forecasting uncertainty for connection capex is at least as significant for EDB DPPs. The capex gating process for DPPs involves interrogation of connection capex forecasts for general and large connections. Sufficient information to enable the wash-up for general connections can be obtained during the gating process. Large connections are catered for within the reopeners, but general connections are the most significant component of our connection capex forecasts (general connection capex exceeds the large customer projects) If a DPP connection wash-up for general connections is not adopted, an alternative is to exclude it from the capex IRIS calculations. We do not believe that it is appropriate for financial penalties or rewards to be included in prices due to forecasting error for this category of capex. Historical levels of spend will not be a good predictor of future demand during the energy transition.
Change the approach to set inflation-adjusted IRIS allowances (based on actual CPI) for the purposes of calculating opex and capex incentive amounts.	Powerco **supports** the proposal to modify the Incremental Rolling Incentive Scheme (IRIS) for EDBs by applying the incentive to real, not nominal opex and capex allowances. Inflation is not controllable for EDBs and adjusting IRIS in this manner is consistent with achieving FCM. As stated in the draft decision paper, inflation forecasting error may not balance out over time because there may be a greater potential for inflation to be significantly above forecast than below forecast. The IRIS incentive recoverable costs to be included in DPP4 prices should be calculated on this basis, otherwise EDBs will not have an expectation of earning a real return during DPP4 due to significant unforeseen cost inflation during DPP3. We support using CPI for the wash-up adjustment because this is consistent with the relatively low-cost nature of the DPP. As the regulatory period progresses, EDBs will need to translate forecasts and opex/capex trade-off assessments into real terms to estimate actual IRIS impacts –while it's an additional complication for estimating IRIS impacts, we support it as a matter of principle to ensure efficiency gains, or costs, are shared correctly with customers.
Change our approach to use the midpoint vanilla WACC as the discount rate for estimating the opex incentive rate	The draft decision proposes to use the mid-point discount rate when calculating IRIS financial rewards and penalties. The practical consequence of this decision will be to reduce the IRIS incentive rate, which is a function of the WACC, assuming the five-year retention period is retained for the opex IRIS. The incentive rate is also currently used in the quality incentive scheme. Powerco **supports** the draft decisions to retain most of the other features of the current IRIS, such as equal incentives for opex and capex, and the five-year retention period. This should be adequate in the near-term when combined with new allowances and incentives for flexibility. Despite this, IRIS does not allow opex and/capex substitution across regulatory periods. As the role of flexibility services increases, we encourage the Commission to work with the industry to ensure there's a pragmatic and enduring approach for treating capex/opex substitution across regulatory periods.

Decision	Powerco response
Amendments to the Innovation Project Allowance	The proposed changes to the Innovation Project Allowance create a more favourable environment for the adoption and implementation of non-traditional and innovative solutions**.** Powerco supports the Commission's proposed amendments to the Innovation Project Allowance, which involve removing the restrictive definition of 'innovation project' and expanding the mechanism to include 'innovation and non-traditional solutions'. This will give the Commission the flexibility to create a wider variety of schemes in the DPP that encourage innovation and the use of non-traditional solutions. This expansion is crucial as the current financial incentives and the higher risk associated with alternative operational expenditure solutions pose significant challenges for EDBs exploring non-network alternatives to delay capital expenditures. As the Commission noted, the EDBs' reluctance to adopt non-traditional and innovative solutions could negatively impact the electricity sector, hinder the growth of the emerging flexibility services market, and potentially raise costs to consumers. We agree that the optimal time to develop these schemes is during DPP and CPP resets. This timing enables the Commission to integrate the latest information and refine the schemes between resets. Powerco looks forward to actively engaging with the Commission in the forthcoming Electricity DPP reset to help shape these schemes.
Form of control for GDBs **(Topic 3e – pg91)**	The draft decision is to maintain the weighted average price cap as the form of control for GDBs, the status quo, as the Commission considers that this best promotes the Part 4 purpose. The Commission's reasons for retaining a price cap rather than moving to revenue cap include: • A price cap provides stronger incentives to tailor expenditure to changes in demand. • Under a revenue cap customers may be at risk of having their service discontinued as expenditure is minimised. • Suppliers have no incentives to spend to retain customers or provide services at a quality they demand. They rather have incentives to reduce costs. Powerco **recommends the Commission reconsider a revenue cap for gas networks** for the reasons we and gas pipeline businesses have previously submitted on during the gas DPP reset[1]. • A change to a revenue cap improves incentives to invest because it removes a GDB's exposure to demand forecasting risk. There is a trade-off, as the change will shift the risk of demand variations during the regulatory period from the GDB to consumers. However, the positive impact for consumers of removing disincentives to invest may be much more significant at a time when reliance on gas networks is high. • The status quo (weighted average price cap) exposes GDBs to regulatory quantity forecasting risk, and this creates incentives to under-invest in response to quantities falling below forecast. Demand forecasting is difficult in the current

[1] https://www.powerco.co.nz/-/media/project/powerco/powerco-documents/who-we-are---pricing-and-disclosures/submissions/2021/commerce-commission---gas-dpp-reset-process-and-issues-paper.pdf

Decision	Powerco response
	environment, and GDBs are exposed to the risk that actual demand will differ materially from the forecast determined by the Commission to set the WAPC. This exposes GDBs to the risk that profitability differs significantly from the Commission's and investors' expectations. In these circumstances, the risks attached to the regulatory demand forecasts may create an incentive to invest less than would be optimal, and less than is in the long-term interests of consumers. • A large proportion (around 50%) of network capital expenditure is largely independent of demand and is required to maintain and operate our networks to ensure it is safe and reliable. • Re-opening price paths for resilience and other events will be easier to apply under a revenue cap. • Gas transmission already operates to a revenue cap.
RAB indexation to inflation **(Topic 3a – pg28)**	The draft decision is to maintain RAB indexation to inflation for electricity distribution businesses (EDBs) and gas pipeline businesses (GPBs) Powerco's view of this decision is: • Electricity: **Support** the decision as it shifts cost recovery to the future when the consensus is that electricity demand will be higher. For example, scenario modelling by the Business Energy Council[2] indicates electricity generation/consumption will almost double by 2060 as part of the economy's transition to net-zero in 2050.  • Gas: **Recommend indexation reviewed** for gas at this or next IM review. Frontier's "declining demand paper"[3] suggests removal of RAB indexation to avoid unnecessarily backloading the recovery of costs from a potentially smaller customer base. This is aligned with managing networks with declining demand. GIDI funding of businesses to shift from gas to electricity is a clear example of reducing demand within the period which is unable to be forecast (driven by

[2] https://times.bec.org.nz/sectors/#electricity

[3] Frontier Economics "Options to maintain investment incentives in the context of declining demand" - A report prepared for Vector, Powerco and Firstgas, February 2023.

Decision	Powerco response
	policy)[4]. The effect of RAB indexation is to push more cost recovery into the future. This means that more costs will need to be recouped from a smaller and smaller pool of future consumers, thus raising the cost burden on each future user. Removal of RAB indexation would reduce the size of the future RAB to be recovered, complementing other approaches it might implement to front-load network cost recovery.

[4] See for example several projects from round 4 which involve gas to electricity conversions https://www.eeca.govt.nz/assets/EECA-Resources/Co-funding/GIDI-Files/Round-4/Round-4-Projects-Map-and-Summaries.pdf

Topic 2: Cost of capital

For this IM review the Commission grouped issues into three topics, each with a 'topic paper' that explains the draft decisions and reasoning on IM decisions relevant to the topic.
1 Financing and incentivising efficient expenditure during the energy transition
2 Cost of capital
3 CPPs and in-period adjustments
This section contains our responses to topic 2: *Cost of capital*.

Powerco own and operate both electricity and gas networks, and our submission covers both services. For ease of reading these two areas have been separated into sections.

Decision Topic	Powerco response
WACC Percentile	Electricity The draft decision on most suitable WACC percentile for EDBs was the 65th percentile to apply for price-quality path regulation. Powerco's view of this decision is… • Any change in the WACC percentile should be justified with clear principled reasoning to do so. • Maintain an uplift on the WACC percentile at the 67th percentile for electricity networks, given the costs of underinvestment are heightened in an environment of accelerated electrification. • The increased electrification of the economy since the 2016 review, as part of the response to climate change, amplifies the cost and risk of underinvestment. • The Commission has not found evidence of overcompensation due to a 67th percentile WACC. Instead, it has published evidence suppliers have been under compensated.[5] This shows customers have not faced unduly high costs. • The objective to maintain regulatory stability supports the retention of at least the 67th WACC percentile. Oxera has prepared a report[6] on behalf of the 'Big 6' EDBs which covers the cost of capital issues relating to Electricity Line Services. We would like to draw attention to the following WACC percentile issues raised in this report: • The Commission has made a tax adjustment in the modelling of the optimal WACC percentile. Given corporate tax is redistributed through the government, which includes consumers, this adjustment is not required. • The $1 billion figure used by the Commission for estimating the impact of underinvestment on network quality is a conservative, bottom of the range figure, using midpoint of the range ($1.45bn) suggests a percentile of **70%**. • Under-investment can delay decarbonisation, in addition to the cost of outages, leading to further social costs. Ensuring networks are ready for the transition through an appropriate WACC percentile means CO2 costs are avoided and transition costs for consumers are reduced.

[5] That is, with reference to evidence on network reliability indicators and returns to networks.

[6] Oxera "Response to the New Zealand Commerce Commission's draft decision for Part 4 Input Methodologies Review 2023 on the cost of capital" - commissioned by the "Big 6" EDBs

Decision Topic	Powerco response
	• The intention of quality and other incentive schemes does not appear to be a substitute for a WACC uplift and are unlikely to prevent underinvestment caused by a WACC that is set too low. • The 67th percentile currently used for EDBs is already at the lower end of the optimal WACC percentile range. We support the ENA submission; we would like to draw attention to the following issues relating to WACC percentile: • There is a concern empirical evidence and modelling are being undermined in favour of regulatory precedent. • Lack of evidence explaining what has changed since the 2014 decision to set the percentile at the 67th. Gas The draft decision on the most suitable WACC percentile for GPBs was the mid-point (50th percentile) to apply for price-quality path regulation. Powerco's view of this decision is… • The draft decision for using the midpoint percentile of WACC for gas is not well evidenced, with no empirical evidence and reasoning for what has changed since the 2014/2016 decisions. • There does not appear to be a clear case for changing the way gas network reliability is incentivised in New Zealand as WACC uplift is not causing excess profits over the last 8 years based on the Commission's analysis.[7] • Maintain an uplift of WACC percentile at 67th percentile for gas networks to preserve incentives to invest in secure and reliable gas networks to support an orderly energy transition. Gas has an important security of supply role during the energy transition to decarbonisation, helping to minimise the impacts of electricity reliability (particularly when affected by above-ground assets). Oxera has prepared a report[8] on behalf of the GPBs which covers the cost of capital issues relating to Gas Pipeline Services. We would like to draw attention to the following WACC percentile issues raised in this report: • The value of regulatory stability, which provides predictability for investors and their investment decisions, as well as more efficient market outcomes. Uncertainty can drive up the cost of capital as investors seek compensation for heightened risk. • Improvements in reliability should be rewarded, not penalised in a regulatory system. A WACC percentile decrease because of increased reliability is not in line with customer interests. • Gas pipeline firms have demonstrated steady profitability without a priori evidence of excessive returns while average customer payments have decreased in real terms.

[7] https://comcom.govt.nz/__data/assets/pdf_file/0020/273413/Trends-in-gas-pipeline-performance-report-2023.pdf, Pg 14

[8] Oxera "Response to the New Zealand Commerce Commission's draft decision for Part 4 Input Methodologies Review 2023 on the cost of capital relating to the gas sector" – prepared for Firstgas, Powerco and Vector

Decision Topic	Powerco response
	• Risking underinvestment in gas network infrastructure—which might occur as a result of removing the WACC uplift—could increase the probability of environmental costs in the future through increased gas leaks. • By setting the WACC at the midpoint for gas networks, the regulatory regime appears to have become more asymmetric, risking underinvestment in the gas network. There are few, if any, financial incentives in place for gas distribution companies that reward maintaining, or improving, the quality of service and reliability of their networks.
Asset Beta	We **support** the maintenance of a combined energy comparator sample due to nature of energy businesses in New Zealand with an uplift for gas pipeline business given the heightened risk due to higher income elasticity of demand and lower gas connection penetration than overseas. We would like draw attention to the following asset beta issues raised by Oxera in the EDB and GPB reports. • There is no reason to exclude daily betas from the Commission's assessment from a statistical significance point of view with standard error being the lowest for this group. • Treating the COVID 19 period differently than other periods when determining asset beta estimates reduces the stability and predictability of the regulatory regime. • Commission estimates of the gas asset beta uplift are between 0.08 and 0.12, closer to 0.10 compared to the 0.05 uplift in the draft decision. There is inconsistency in the reasoning for choosing 0.05.
Tax-adjusted Market Risk Premium (TAMRP)	We **support** an appropriate method of calculation for the TAMRP that considers current data and using modelling that is not overly sensitive to input assumptions, to produce consistent results. This suggests **7.5%** (not 7.0% as in the draft decision). Judgement is used in estimating this component and there is insufficient reasoning to reduce from 7.5% used in 2020 decision. We would like draw attention to the following issue relating to Tax Adjusted Market Risk Premium (TAMRP) raised by Oxera in the EDB report: • There are limitations of using the dividend growth model approach and collection of survey data, which is not used by the AER or Ofgem in their market return estimates. • The updated estimates of TAMRP are closer to 7.50% than to 7.00% if the Commission's rounding approach is continued to be adopted.
Financeability	The draft decision is not to adopt a financeability test, as the Commission considers that an efficient company is unlikely to face financing issues. Powerco **supports** the inclusion of a financeability test on a benchmark company that proves the cost of capital settings determined in the IMs will enable the company to maintain the required credit rating throughout each regulatory period. This would ensure EDBs and GPBs receive sufficient funding for decarbonisation and increased electrification.

Decision Topic	Powerco response
	We would like draw attention to the following financeability issues raised by Oxera in the EDB report: • If a financeability concern is identified only when revenues are set, the Commission will not be able to use the WACC allowance as a potential remedy. • Two options to overcoming the challenges of running a financeability test at the setting of the price quality path have been proposed including flexibility in WACC setting methodologies at a price/quality reset and undertaking provisional cash flow forecasts. • Providing equity issuance costs while assuming that dividends are paid is supported by international precedent.

Topic 3: CPP and in-period adjustment mechanisms

For this IM review the Commission grouped issues into three topics, each with a 'topic paper' that explains the draft decisions and reasoning on IM decisions relevant to the topic.
1 Financing and incentivising efficient expenditure during the energy transition
2 Cost of capital
3 CPPs and in-period adjustments
This section contains our responses to topic 3: *CPPs and in-period adjustments*.

Table 1: Responses to

Decision	Powerco response
Introduce a reopener event	**Support** the revised definition.
Not introduce timeframes for the Commission to evaluate reopener applications	The IMs must include a process with reasonable timing expectations to provide certainty to customers and suppliers**.** We understand the Commission's concern about resourcing – this mirrors the position suppliers are in when a customer comes to us or when an event happens. We expect reopeners will be relied on more over the DPP4 and DPP5, whether it be as a tool to manage forecast uncertainty or simply due to unforeseen events. For this to work for customers, there needs to be some certainty of process. As an example, generation connections have time requirements under Part 6, and this could extend to demand. Economic regulation should, at a minimum, align with the approach. The mechanism (timeframes, staging) could be implemented outside the IMs e.g., as a guideline. Having an IM requirement (commitment) to produce and follow the guideline would be advantageous. Either way, we encourage the Commission to set timeframes based on what a great customer outcome looks like. This could be as simple as defining a target date by which the applicant can expect to hear back from the Commission. Release valve mechanisms can be built in to address circumstances when resources or other reasons mean achieving the target is not possible (like Part 6 of the Code). This approach could be monitored too – a great way for the Commission to demonstrate to customers how they are playing their part to support NZ's decarbonisation.
DPP reopeners and future circumstances (Ch6)	**Support** the inclusion of opex by referring to "expenditure" rather than "capex" in IM definitions. **Support** the extension of drivers to include resilience-related expenditure. We agree that most resilience type expenditure should occur as part of a supplier's ordinary programmes of work [6.71]. However, circumstances may arise during a regulatory period where this is inadequate, and a specific resilience driver in the IMs is appropriate. **Recommend the Commission reconsider its position on contingent allowances.** We agree there could be limited use for this mechanism, though it could equally prove to be highly effective and simple if appropriate. Potential examples include if there are costs contingent on an asset transfer from one regulated supplier to another, or as part of a transition off CPP, or as part of an exogenously driven decision which the supplier must respond to (e.g. for Powerco there could be network or non-network activities/costs relating to the scope and timing of Transpower's decisions in the Bay of Plenty https://www.transpower.co.nz/projects/wbop). Should it be needed, the contingent allowance would be a practical and time-bound solution which could be

Decision	Powerco response
	factored into future forecasts at the next reset, limiting any concerns about incentive impacts. Transparency will also be an effective tool for addressing any concerns about the scope of expenditure.
Reopener thresholds (Ch7)	Powerco recommends the Commission set a $2.5m threshold for all EDBs**.** We **do not agree** with the rationale of the Commission to differentiate the reopener thresholds across EDBs. Given expenditure allowances have not been set, it is better that regulatory settings err on the side of more rather than less use given the dollar threshold affects the update of the reopener as an **option** should the circumstances and evidence support it. The Commission's settings appear to be based on three concepts (**emphasis** added): • "suppliers should be able to manage **relatively small changes in expenditure** requirements within the price path set for them" e.g., para - 7.4 • A $5m cost threshold for Powerco and Vector on the basis of "the more significant FNAR and expenditure allowances, and **accordingly the greater ability to reprioritise** within expenditure allowances" (7.41) • If thresholds are lower there is a risk that there would be **significant increases in the volume of re-opener applications**, which would increase compliance costs and complexity in the regime" 7.52 We have a different view: • $5m is a large change in expenditure – we do not consider it a relatively small change. • The ability to re-prioritise expenditure is contingent on expenditure settings which are unknown, along with the realities applying at the time. We appreciate the endorsement about our ability to reprioritise expenditure, though this does not mean it should be assumed as a feasible option in the timeframes available that has no detrimental impact on consumers or asset management practices. • It is overly cautious to presume lower thresholds will of themselves increase the applications, especially without DPP forecasts being known. There is a transaction cost to suppliers, including audit and governance requirements, which will support genuine applications. • It will also create a non-level playing field for customers wanting to connect (generation or load) to Powerco/Vector vs another EDB. • Should EDBs merge over the period to be of a similar size to Powerco or Vector, they will still have the lower threshold applying. A better view: A positive, permissive, and simple approach would be to set the thresholds at a significant ($2.5m) level for all EDBs on the basis that **genuine circumstances will drive their use**. We are confident that the transparency of the process and rationale will ensure only genuine applications are proposed. If they are genuine, the effort will be worthwhile for customers. We expect the application process can be streamlined as examples are processed as this will be in everyone's interests. We **support** the application of cost tests rather than revenue tests (7.24). This is an example of meaningful improvement to the IMs.
Remove the $30m threshold (Ch 7)	We support removal of the $30m upper threshold.

Decision	Powerco response
	We agree that removing the cap would provide an alternative to a single issue CPP [7.72]. We suggest the IMs (or guidelines) outline the principles the Commission will apply when assessing if it "… *think(s) the expenditure is better suited to a CPP application*" [7.74].
Introduce a 'Large Connection Contract' (LCC) mechanism (Ch 8)	We support the LCC concept and suggest the threshold(s) be lowered to align with reopener thresholds (including a $ threshold) Powerco **supports** the Commission's draft decision to implement the 'Large Connection Contract' (LCC) mechanism. This aims to tackle the issues related to unexpected large connections, given the constraints of EDBs' expenditure allowances and the application processes for DPP/CPP reopeners. The LCC mechanism offers a practical solution by excluding the connection costs from the EDBs' regulated expenditure and allowing the exclusion of connection assets created under LCCs from EDBs' Regulated Asset Bases (RABs), subject to certain conditions like workable competition and connection size. We agree with the potential benefits of this approach. The LCC mechanism allows large customers to connect to the network on their preferred timeline while agreeing to a commercially negotiated cost. To further enhance the effectiveness of this mechanism, we propose the following improvement: **add a value threshold e.g., $2.5m dollar threshold in addition to a MW threshold:** • This change will create a meaningful link between the qualifying criteria and the main issue - the limited expenditure allowances of EDBs. The additional MW capacity alone doesn't solely determine the connection cost. Actual costs can vary significantly based on site-specific factors, such as proximity to a zone substation or distance from the existing sub-transmission network. For instance, we're currently handling a connection request for an additional capacity of 6 MW, which incurs a cost of about $13 million. • By incorporating a dollar trigger, connection costs are appropriately considered, and connections with substantial costs but lower MW capacity can still proceed without unnecessary delays. This approach will provide greater fairness in progressing customers' connection requests, including between exempt and non-exempt EDBs. We believe a suitable dollar threshold would be $2.5million (net of any capital contributions received), aligning with other DPP re-openers thresholds.

Attachment 1 – Information about Powerco and our network

Providing an essential service

We bring electricity and gas to 1.1 million customers across the North Island. We're one part of the energy supply chain. We own and maintain the local lines, cables and pipes that deliver energy to the people and businesses who use it. Our networks extend across the North Island, serving urban and rural homes, businesses, and major industrial and commercial sites. We are also a lifeline utility. This means that we have a duty to maintain operations 24/7, including in the case of a major event like an earthquake or a flood.

The cost of operating our business is not dependent on the amount of gas or electricity we distribute in our networks. These costs reflect the need to maintain the safe operation of the network and are mostly driven by compliance with safety regulations. This includes replacing assets when they reach their end of life. Additional costs to grow the size or the capacity of the network are often met by customers requiring the upgrade or new connection.

Under Part 4 of the Commerce Act, Powerco's revenue and expenditure are set by the Commerce Commission as part of monopoly regulation. We are also subject to significant information disclosure requirements, publicly publishing our investment plans, technical and financial performance, and prices. The regulatory regime allows us to recover the value of our asset base using a regulated cost of capital (WACC) set by the Commission, and a forecast of our expenditure. Every five years, the Commission reviews its forecasts and resets our allowable revenue. This process is designed to ensure the costs paid by customers for us to manage and operate our network is efficient given we are a monopoly and an essential service.

Our electricity customers

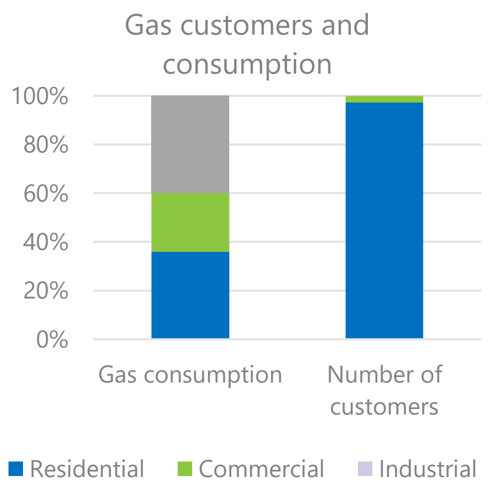
Powerco is New Zealand's largest electricity utility by the area we serve. Our electricity networks are in Western Bay of Plenty, Thames, Coromandel, Eastern and Southern Waikato, Taranaki, Whanganui, Rangitikei, Manawatu and Wairarapa. We have 28,441 km of electricity lines and cables connecting 344,000 homes and businesses. Our place in the electricity sector is illustrated below.

Our network contains a range of urban and rural areas, although is predominantly rural. Geographic, demographic, and load characteristics vary significantly across our supply area. Our development as a utility included several mergers and acquisitions that have led to a wide range of legacy asset types and architecture across the network.

Powerco is one of 29 electricity distribution companies. Our customers represent around 13% of electricity consumption (similar in magnitude to the Tiwai aluminium smelter) and around 14% of system demand. Powerco's network is almost three times the size of Transpower's in terms of circuit length. The peak demand on our combined networks (2022) was 986 MW, with an energy throughput of 5,266 GWh.

Our gas customers

Powerco is New Zealand's largest gas distribution utility. Our gas pipeline networks are in Taranaki, Hutt Valley, Porirua, Wellington, Horowhenua, Manawatu and Hawke's Bay. We have 6,100 km of gas pipes connecting 112,000 homes and businesses to gas.



Our customers consume around 8.6 PJ of gas per year. Our industrial customers are less than 1% of our customer base and consumer approx. 40% of gas on our network. Our residential customers are 97% of our customer base and consume approx. 35% of gas on our network. The remaining 25% of gas is consumed by our commercial customers. Around 30% of our larger customers are in the food processing sector, around 20% in the manufacturing sector and around 10% in the healthcare sector.

Our network footprint