POWERCO

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Via email infrastructure.regulation@comcom.govt.nz

Tēnā koutou,

Powerco feedback on questions about EDB expenditure forecasting

Powerco Limited (Powerco) welcomes the opportunity to provide a submission on the Commerce Commission's questions about EDB expenditure forecasting.

Attachment 1 provides Powerco's detailed feedback. We look forward to engaging with the Commission and stakeholders in the next phase of the review.

If you have any questions regarding this submission or would like to talk further on the points we have raised, please contact Nathan Hill [redacted].

Nāku noa, nā,

Andrew Kerr
Head of Policy, Regulation, and Markets
POWERCO
[redacted]

Attachment 1: Powerco's detailed feedback on the Commission's questions

Question: How are EDBs obtaining confidence in establishing the requirements they are forecasting to meet, including but not limited to demand, resilience, and reliability?

We use the following methods to establish and gain confidence in the requirements we need to meet.

DEMAND FORECASTING

Connection & industrial/commercial (organic) growth

We continually improve our forecasting methodology and data by using a probabilistic approach (use of demand profiles and operating envelopes) and through better integration of short-term customer-driven investment needs. For example, we are using the results of modelling customer response/uptake regarding DER/DSR options.

Electrification (significant change expected)

- Residential connections: We model the demand contribution from each electrification component (EV, Gas Heating, PV, ESS) on relevant domestic installations. We will also apply a spatial, demographic & temporal lens.
- Process Heat: Leveraging data such as DETA survey disaggregated to substation level to estimate future needs.
- Given the uncertainty in many aspects, we use a scenario approach

Forms of assurance

We have used cross-industry comparisons to validate our demand assumptions, especially Transpower's Te Mauri Hiko. We are also actively engaged in several industry forums and reports and are undertaking trials of EV charging patterns.

LEGISLATIVE CHANGE

Our approach to legislative change is primarily to monitor and react. We can't realistically anticipate and forecast some of these changes. We know that climate policy could reasonably impact demand drivers/timing. So, we use scenarios that effectively cover a reasonable spectrum of policy/ political outcomes.

RESILIENCE

Increased exposure to adverse environmental conditions from climate change and other environmental factors and customers' increasing reliance on electricity have brought network resilience into strong focus. Accordingly, we are developing a physical adaptation strategy for our assets to ensure the appropriate resilience of our networks.

We identify resilience needs and forecasts by:

- Developing climate pathways and scenarios
- Reviewing asset risk exposures (e.g. inundation) to understand shorter-term mitigations.
- Reviewing asset design standards for a changing climate and associated cost impacts
- Engaging consultant expertise and sourcing improved climate data

RELIABILITY

We identify the inputs for reliability forecasting by:

- Undertaking surveys and research to understand customers' price/quality preference for reliability (Value of Energy Not Served rates) and apply this more systematically to load types.
- Monitoring societal and behavioural changes such as increased working from home and electricity dependence

Question: Are there specific events or metrics that can be forecast and then observed that indicate that a step change in expenditure is required or an alternate scenario is playing out?

Expenditure step changes in the near term are most likely to be caused by the electrification of society. However, asset renewal/replacement step changes related to aging asset fleets are also possible later in the planning period.

ELECTRIFICATION STEP CHANGES

Our current top-down modelling of electrification expenditure step changes uses demand as a proxy for network investment, assuming a linear relationship between increased system demand and network expenditure to maintain existing levels of network performance. We will move in future to bottom-up modelling, identifying specific localised constraints, risks/costs, investment needs, and even nominal investments.

The main expenditure sensitivities in the AMP period are related to the timing and scale of decarbonisation, particularly EV charging and process heat electrification. We are not signalling an expenditure uplift related to new connections, but broad uncertainty remains, as has been evident in recent years.

Expenditure forecasts are more sensitive to timing (tipping points of accelerated uptake) than saturation levels (density of uptake). Whilst the expenditure quantum is not affected by the transition rate (from trigger to saturation), our modelling has alerted us to a delivery risk. Some swift transitions could only be possible to react to if some investment precedes the surge.

We monitor the following potential "leading indicators" of electrification expenditure step changes:

Electric vehicle (EV) uptake

We consider that vehicle prices, national uptake rates, and government subsidies are the primary triggers for accelerated EV uptake. Metrics such as the costs of EVs can be good indicators of investment timing needs but are less helpful in working out the level of investment (expenditure quantum) since there are complex non-linear relationships.

To forecast the impact (and timing) of EV uptake on demand and expenditure requirements, we are:

- Trialling EV charging schemes to understand charger sizes, rates, diversity and controllability
- Planning to map EV uptake to network areas
- Engaged in industry forums about charging control, standards and protocols
- Considering possible commercial/pricing models, as charging control (via price or directly) will be the single biggest determinant of the overall demand impact of EVs. The difference in the impact of non-controlled vs time-shifted charging is likely to be highly material for peak demand.
- Monitoring heavy transport decarbonisation research. Our current assumption is the electrification of light transport only.
- Monitoring commercial charging

Process heat electrification

To forecast the impact (and timing) of process heat electrification on demand and expenditure requirements we:

- Use the best available information from cross-industry surveys and our customer engagement. Timing is the fundamental uncertainty.
- Monitor developments in high-temperature systems and bio-fuel alternatives that would impact electrical demand assumptions.

- Consider customer activity from early adopters as the best leading indicator of a pending tipping point. Notably, evidence suggests that large and high-temperature heat processes are unlikely to impact networks because they will either connect directly to the grid or use alternative energy sources.

Domestic gas transition

We expect a gradual transition that will require a slow/later response. Mass conversion, especially of existing installations, will likely follow adjustments in appliance costs (gas and electric) and carbon and gas prices. Political decisions about exploration are also pertinent. Mass conversion of existing installations is likely to be forewarned by new gas connections drying up.

PV and/or Batteries (ESS)

We anticipate the investment triggers to be solar panel costs and, more importantly, battery costs. Wholesale energy prices will also have an impact.

Solar is already showing signs of exponential acceleration in uptake, both in small domestic and large dedicated farms. Network investment due to a MW solar is less than that due to a MW of load (demand) or can be customer-funded, so it is less critical to expenditure forecasts.

Batteries, at least initially, should have load profiles that are complementary to network load profiles and, therefore, should not add additional demand or cost to the network. In many cases, if agreement could be reached with owners, batteries could, in fact, contribute to reducing peak demand. Our demand scenarios assume a certain degree of network support from customer batteries.

The potential for additional leading indicators or proxies appears limited. Currently, we do not see any helpful expenditure proxies that do not at least result in a forecast demand increase.

STEP CHANGES DUE TO AGING ASSET FLEETS

Our CPP renewal plans lifted investment to a sustainable level to manage the renewal needs for our overhead network and zone substations. The overhead network is massive – it will continue to require substation renewal for the next ~20 years.

Later in this planning period, we may need to start proactively replacing parts of our underground cable network, which typically haven't attracted much renewal. This expenditure would be a new step change. There is still uncertainty around the timing and size of this potential step change, and we are working on improving our asset health understanding of this fleet. With the increasing electrification needs, we will also try to coordinate renewals with growth upgrades – ensuring we do the work once.

Question: How are EDBs obtaining confidence that their proposed expenditure plan is the most effective and efficient solution for the forecast level of demand, resilience requirements, and reliability levels?

Before an investment occurs, there are various approval processes. The level of scrutiny varies based on the size, urgency, and complexity of the work. Chapter 10 of our 2021 Asset Management Plan discusses the processes and analytical tools we use to identify needs and make investment decisions. [1]

AREAS OF RELATIVE CERTAINTY

Renewals

Most of our renewal investment forecasting is based on bottom-up condition-based failure risk modelling, using asset condition and criticality information as inputs. This approach to renewal forecasting gives us a high degree of confidence in our renewal forecasts. Improved asset health and criticality information in the future will support refinement of these forecasts but is unlikely to change our forecasts materially.

Some areas of uncertainty do exist, however. We are reviewing our resilience planning approach, with one option to build additional resilience into certain parts of our network at the time of asset renewal (at a small incremental cost). Uncertainty with our growth forecasts also influences our renewal forecasting, with the potential to coordinate growth and renewal needs potentially reducing the future renewal forecast (with renewal happening under a growth & security budget).

Maintenance

Our predominantly time-based approach to preventive maintenance lends itself to a high degree of forecasting certainty. As we introduce more reliability-centered maintenance practices, we will refine our maintenance standards and approaches. However, don't expect this to materially impact forecast levels (some assets may get maintained more, others less).

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[1] Powerco 2021 AMP https://www.powerco.co.nz/-/media/project/powerco/powerco-documents/who-we-are---pricing-and-disclosures/disclosures/electricity-disclosures/2-electricity-asset-management-plans/2021-electricity-asset-management-plan.pdf

Corrective and reactive maintenance forecasts are typically trend based. With an overall approach of managing asset risk at levels similar to today, we don't anticipate significant long-term changes to this expenditure (noting there is uncertainty in any given year due to storm activity, but this averages out in the long term).

AREAS OF LESS CERTAINTY (growth, flex services, other opex)

System growth and consumer connection

Growth forecasts are inherently linked to electricity demand forecasts. Trend-based demand forecasts have historically been fairly reliable for input into network planning processes. Demand forecasts are now in a transition period, with a high degree of uncertainty related to the impacts of process heat conversion, electric vehicles, residential gas-to-electricity switching, and distributed energy resources.

We are developing different demand forecast scenarios based on different assumptions related to the uncertainties listed above. These scenarios use information from other industry sources or research (e.g. MBIE, Transpower's Te Mauri Hiko) combined with knowledge of our network and customer information.

At a top-down level, we use these different scenarios to examine and understand potential investment profiles. We currently use a base case demand forecast for our bottom-up growth area planning but are working towards using different demand forecast scenarios in these area plans. Using different demand forecasts at an individual investment level is important for testing options selection under various scenarios.

Long-term consumer connection investment has similar levels of uncertainty as system growth. Long term, we expect this investment to increase, driven by decarbonisation, but the size and timing of the demand growth (and the corresponding investment) are uncertain. Short-term economic fluctuations can also impact this portfolio.

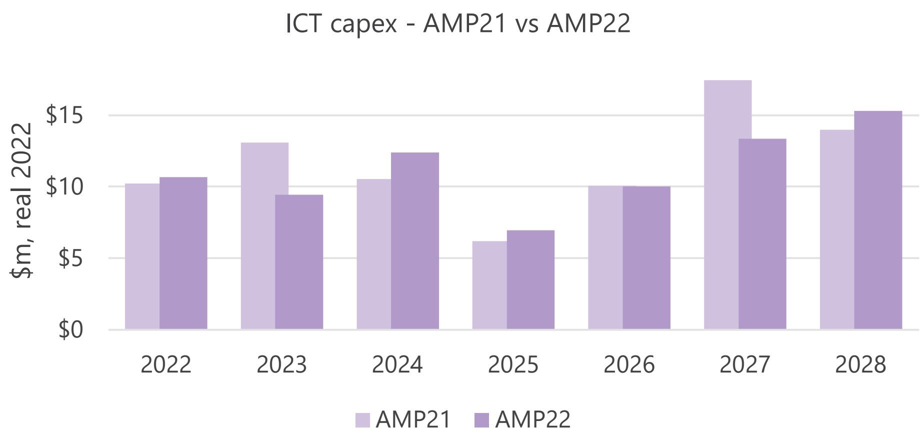
Cyber security and digitisation

Expenditure related to cyber security and greater use of digitisation and data is somewhat foreseeable over the near term, but the scale and timing of this expenditure is uncertain. This can be an issue when the practicalities and priorities of projects span reset periods.

We commented on costs relating to cyber and digitilisation as part of our DPP3 reset process[2]. For example, our 2022 AMP update included an additional $2.5 million in for an overhaul of Powerco's business intelligence as part of several changes from the previous AMP. There were also reductions in costs.

Non-network assets include assets that support the operation of the electricity business, such as information and communications technology (ICT) and asset management data. Investment in ICT and data quality is forecast to grow, driven by the need to reduce technology risk and strengthen our core business operations through the delivery of foundational business practices and technology.

The 2022 AMP forecasts reflect our best estimate of Powerco's ICT requirements. ICT capex can vary from year on year as seen in comparison below of our 2021 and 2022 AMP. Timing of projects can change at short notice depending on needs of the business and how we efficiently manage priorities across the business.



Draft decision	***AMP21 forecast***	***AMP22 forecast***	***Explanation of differences***
DY24-25: Use AMP21 forecast of ICT capex	*$16.7m*	*$19.3m (+$2.6m)*	• *additional $2.5m in DY24 for Project BIRD (an overhaul of our business intelligence, reporting and data management systems)* • *increased Advanced Distribution Management System[3] (ADMS) expenditure of $1.7m (from $1.8m to $3.5m) included in DY25* • *reductions in other ICT areas -$1.6m*

2 https://comcom.govt.nz/__data/assets/pdf_file/0027/293085/Powerco-Submission-on-Powerco-transition-to-DPP3-draft-decision-15-September-2022.pdf, page 12.
3 Page 332, Powerco Electricity Asset Management Plan 2021

While this expenditure was not included in the Commission's assessment of Powerco's capex allowances[4], it is indicative of the scale of cost and the fluidity in timing associated with efficiently delivering projects of this nature.

Uncertainty around Flexibility (Non-network)

The uncertainty around flexibility will make it challenging to forecast related expenditures and regulatory allowances. Any Opex allowance for future flexibility will intrinsically be highly speculative and have no helpful precedent or trend on which to base it.

We could manage the uncertainty in expenditure forecasting more effectively if the Flexibility purchase is a pass-through or recoverable cost or in period adjustments are made. Alternatively, it could be treated as negative revenue in the same fashion as demand side response customers receive a "credit" related to the flexibility they offer to the network.

Flexibility is also very dependent on wholesale market prices. We are primarily observers and have limited visibility of significant drivers.

Expenditure related to "smart networks", such as network visibility and DSO enablement, is intrinsically "low confidence" since the requirements or timing are yet to be clearly defined. However, these work streams again have a high risk of investing too late.

GAINING CONFIDENCE IN AREAS OF LESS CERTAINTY

For areas of less investment certainty, to gain more confidence we:

- Participate in and lead industry research in areas such as demand flexibility, electric vehicles
- Implement network trials of new technology to understand the implementation of them on our network, their benefits in understanding network demand, and their ability to support demand flexibility
- Develop more sophisticated network modelling capabilities to test the network impacts of various future demand scenarios.
- This work is ongoing and informs our Asset Management Plan forecasts.

Question: How are EDBs getting confidence that their expenditure plans are deliverable, particularly if they involve a significant increase from historic levels?

[4] See 3.159 in https://comcom.govt.nz/__data/assets/pdf_file/0016/300139/PowercoE28099s-transition-to-the-2020-2025-DPP-Final-reasons-30-November-2022.pdf

We know delivery will be a challenge. Resourcing for our CPP was a significant challenge, and now, for the foreseeable future, electricity networks in New Zealand will need to respond to rapid but uncertain demand growth, driven mainly by the electrification of our society. To appropriately meet this need, we will have to increase and accelerate investment programmes, requiring us to invest somewhat ahead of the actual customer need arising.

A Just in Time approach to investment will be too late (extending network capacity involves considerable lead times, especially if a resource consent is required) and will likely lead to an unmanageable delivery 'spike'.[5]

Given this rapid but uncertain demand growth, EDBs should strive to maintain an economically justified capacity margin on their assets to respond to customer upgrade requests reasonably quickly. Suppose customers have a long wait for their requirements to be met. In that case, it could cause them to delay or forego their decarbonisation plans or drive them to other, potentially less efficient, non-electricity solutions.

Our forecasts consider these challenges by looking at the need to invest ahead of time to 'flatten the delivery curve'. We are still developing this area, and further bottom-up analysis will help.

We are beginning to engage with our service providers about future resourcing. We are proactive in supporting our service providers to develop and train new staff. In addition, we are working on cross-industry groups to encourage people to join the energy industry.

Cost escalation also remains a significant risk to delivery. Unit rates (for expenditure estimation) have increased drastically recently and are very volatile. Inflation and wage pressure could exacerbate this.

Renewal / Growth Trade off

There are potential efficiencies in aligning the timing of renewal and replacement investments (needed due to aging asset fleets) and capacity upgrades needed for electrification. However, co-optimisation will require careful risk management (managing some reduced network performance). We plan to develop data and modelling to implement bottom-up forecasting in the next two years to enable this co-optimisation.

Deliverability under Scenarios

[5] Building a new feeder or substation is an example of network capacity lead times – the average lead time for these builds is around 3-4 years.

Under a high-growth scenario, Just in Time delivery is practically unachievable. Hence, Powerco's "invest in support of customers" strategy schedules some investment before the theoretical optimum need.