Submission to Part 4 IM Review 2023 Draft Decision

19 July 2023

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Submission and contact details

Consultation	Part 4 IM Review 2023 Draft Decision
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Release of information

This version of the report contains no confidential information and can be publicly disclosed.

1 Supporting submissions

There are three other submissions being made separately that respond to the Draft IM Decision on our behalf. Figure 1 provides details of these submissions, including what Draft IM Decision topic they are providing a response to on our behalf.

Figure 1- separate submissions made on WELL's behalf.

Submitter	Submission name	Topics the submission is providing on WELL's behalf
Oxera	Response to the New Zealand Commerce Commission's draft decision for Part 4 Input Methodologies Review 2023 on the cost of capital	• Cost of capital • Cost of debt washup • Financeability
Frontier Economics	A review of the limit on EDB price increases	• Price cap and revenue washup • Financeability (used as a supporting example)

Submitter	Submission name	Topics the submission is providing on WELL's behalf
ENA	ENA submission on the Input Methodologies review draft decision	• Wash-up account • Cost of capital • Non-policy drafting and practical issues

The Electricity Network Association (**ENA**) has also provided a submission in response to the Process and Issues paper. WELL is a member of the ENA and participated in the submissions development. WELL has responded directly on most topics rather than rely on the ENA to provide a response on our behalf (with the exception of the topics highlighted in Figure 1).

2 Introduction

Wellington Electricity Lines Limited (**WELL**) welcomes the opportunity to make a submission in response to the Commerce Commission's (**Commission**) Part 4 IM Review 2023 Draft Decision consultation which is provided in three topic papers, '*Financing and incentivising efficient expenditure during the energy transition topic paper', 'Cost of capital topic paper'* and *'CPP and in-period adjustment mechanisms topic paper'*. This submission refers to the three papers as the '**Financing & Incentives Paper**', '**Cost of Capital Paper**' and '**In-Period Adjustment Paper**' respectively.

In May 2022, the Government released its overarching Emissions Reductions Programme (**ERP**) which will guide the development of detailed sector programmes. The ERP will significantly increase electricity demand and New Zealand reliance on the Electricity network as its primary energy source. Electricity Distribution Networks (**EDBs**) will have to build and develop new capacity and capability to deliver the demand increase. This will require a step change in investment, and in resources and capability to deliver that investment. A higher reliance on electricity as the primary energy source for New Zealand homes and many businesses is likely to also mean that customers will demand new quality measures, and potentially, a higher level of reliability. Changes are required to the current regulatory framework to support these changes and to continue to incentivise EDBs to invest.

Changes to address demand uncertainty

The Draft Input Methodology (**IM**) Decision recognises that EDBs will need to build new capacity to meet the forecast increase in electricity demand and that there will be uncertainty about when to build that new capacity. We note and support the changes the Commission are proposing to provide

EDBs with more flexible regulatory mechanisms. The expanded range of reopeners and the large connection contract mechanisms provide new tools that will allow EDBs to adjust their work programmes and allowances to changes in customer demand.

These changes provide some additional flexibility, but further changes are needed to avoid customers and EDBs having to fit their work programmes around the regulatory rules and time frames. For example, reopeners will only be useful in a limited set of situations because they require an application to be made, the project designed, build and commissioned before the end of the regulatory period. This means any project requiring significant spend in the remaining years of the regulatory period but would not be commissioned until the next regulatory period, would not be eligible for a reopener. A simple change to base reopener allowances on expenditure (rather than asset commissioning) could help avoid customers projects being delayed because they can't fit within the boundaries of a regulatory period.

Restricting reopeners for general growth (from EV uptake or the electrification of gas appliances) to foreseen projects is unnecessarily restrictive. The government still hasn't settled on its gas strategy, the outcome of which could change a networks network growth capex requirements. We also think contingent reopeners, new pass-through costs and contingent allowances could all be useful in different circumstances, and we think including them in the IMs will provide the Commission with more regulatory flexibility when they consider how they will set the next DPP price path.

Care must be taken not to restrict the allowances available to networks delivering the step change in investment. We are entering a period of rapid and uncertain growth where the industry will set the pace of New Zealand decarbonisation. In the past a conservative approach to setting allowances and incentives was appropriate in a low growth environment that focused on asset replacement and cost efficiency. The operating environment has changed, and customers and the government will now expect EDB to keep pace with electricity demand. The cost of not keeping pace with demand will be greater than the efficiency savings that could be provided by tightly controlled access to allowance. The ability to match allowances with customer requirements is central to delivering the purpose of Part 4, specificality, providing EDBs with incentives to invest.

Fast-track some of the proposed changes

We note that final IMs will not come into effect until the next DPP or CPP price paths are set. Customers would benefit from the immediate (immediate being the gazetting of the final IM decision) implementation of IM changes that provide networks the ability to access additional allowances in response to large customer connection projects. These changes can be applied without impacting the efficient operation of existing price/quality decisions (i.e. they are regulatory period agnostic). We ask that the Commission make these mechanisms available for the remainder of the DPP3 regulatory period. Specifically, we would like the immediate introduction of:

- Changes made to the reopener mechanism to allow large projects to be started this regulatory period and Commissioned in the next
- The large connection contract mechanisms

Customers are rapidly electrifying and we have received multiple requests for large demand increases (and supporting network reinforcement) that customers want started within the next year, but the projects won't be Commissioned until after April 2025 (and are therefore not eligible for a reopener). Having immediate access to the IM changes would allow us to deliver these projects within our customer timeframes. These are public works projects that provides Wellingtonians with important new services like public transport electrification, electrification of hospital gas use and wastewater treatment improvements.

Still problems to solve

We note that there are still regulatory issues where the Draft IM Decision reflects the best choice of the potential solutions identified, but the solution do not provide a good long-term solution. Part 4 provides the minimum review periods for the IMs (seven years) and do not restrict the ongoing development of the IMs in-between reviews. The DPP price-quality reset for example, regularly update the IMs with changes for new regulatory mechanisms. We believe additional workstreams are needed to solve residual issues. Specifically:

1. To find a cost efficiency mechanism that allows opex and capex substitution across regulatory periods. This is needed to support the efficient use of flexibility when considering wire alternatives. Relying on allowances for flexibility (rather than capex/opex substitution) is a short-term solution because of the difficulty in being able to forecast these allowances accurately.
2. Develop a better inflation forecast method or ways of avoiding forecast errors (i.e. removing the need to forecast inflation). While the RBNZ maybe as good at forecasting inflation as the other options considered, it's still does not provide an accurate inflation forecast.

Further scrutiny needed

Some of the Draft IM Decisions are new and complex and we are still uncertain about their impact on cashflows, cost saving incentives and other regulatory features. The five-week time frame limits what testing can be done. Specific examples include:

1. The debt washup mechanism is a unique solution to the impact of inflation forecast errors on the debt allowances that is not used in any other regulatory jurisdiction. The illustration on how the mechanism will apply isn't clear and includes inputs from the price rests, making it difficult to model and test. What modelling we could do in the five-week time frame shows that it does result in volatile cashflows.

2. The revenue path wash-up mechanism simplifies the washup process which we support. However, there are aspects we think can be improved and aspects that need clarifying.

These changes weren't proposed during the issues discovery phase of the IM review and the five-week window hasn't provide sufficient time to review what are unique and new solutions. The debt washup solution is also unique to any other regulatory jurisdiction and therefore a higher level of verification is needed to test it works as expected and that all of the consequences and impacts are known.

We believe that additional workstreams are needed in parallel to the DPP4 price reset to test these mechanisms. The final decision on whether to apply these changes should wait until users have confidence in how they will operate and to confirm that other solutions won't provide a better option.

Calculating a more robust cost of capital

We, along with the other five large distribution networks have commissioned Oxera to review the Draft IM Decision. Oxera have recommended a number of important changes where better estimation methods or data inputs provide more robust estimation of the cost of capital. In summary:

- The Draft IM Decisions estimation of the risk-free rate is not supported by the evidence, specifically, the term of the government bonds do not have to match the length of the regulatory period and a longer terms tenors provide a better estimation of debt costs. There is also a strong case to add a convenience yield premium and by not doing do underestimates the risk-free rate.

- The Draft IM Decisions approach to the debt premium exposes networks to uncertainty, and a higher term credit spread differential is supported by the evidence.

- There are more robust approaches to calculating the tax-adjusted market risk premium (TAMRP). The more robust estimation methodologies that underpin the TAMRP range point to an estimate that is closer to 7.5% than to the 7.0% proposed by the Commission. The figure of 7.5% is also consistent with the broker estimates.

- The asset beta allowance underfunds the networks and is a deviation from the Commission principles-based approach to the review. Compared with the Commission's preferred asset beta estimate of 0.35 for energy networks, an average of daily, weekly and four-weekly estimates for the last two five-year periods is 0.37, while the 75th percentile of the range (which is consistent with the percentile that the Commission's chooses for asset betas in its Draft IM Decision within its proposed range) of these estimates is 0.39.

- The evidence does not support a reduction in the WACC percentile from the 67th to the 65th. The 67th percentile was already a conservative estimate with evidence supporting an even higher uplift.

- We do not think that RAB multiple provides a sensible reasonableness check because of the many factors influencing a RAB multiple. The more robust asset risk premium–debt risk premium (ARP–DRP) framework shows that WACC has been underestimated.

- Increasing RRP related investment requirements could create financeability issues in suppliers operating efficiently under the regulatory benchmark assumptions. A financeability test should be introduced to ensure networks are adequately funded and are incentivised to invest.

Improving regulatory certainty

Many of the regulatory mechanisms include subjective elements or provide the Commission the ability to apply a wide range of responses. This provides the Commission the ability to flex their decision making to find solutions that best suit an issue. However, there is a balance. Networks also need regulatory certainty so that they can invest confidently with the expectation that they will have the allowances when they are needed and that their owners will earn a real return for that investment. Too much decision-making flexibility means that EDBs won't be confident of the upcomes of the regulatory rules. Examples of where we believe changes could improve regulatory certainty (and avoid eroding a suppliers confidence to invest) are:

1. Guidelines to support a CPP application, ensuring the application provides all of the information needed for the Commission to make an efficient decision.

2. Support the reopener IMs with guidelines and example assessments to assist suppliers to provide applications that can quickly and efficient assessed and to provide customers and suppliers with a high degree of confidence of whether a reopener will be approved.

3. Removing reopener assessment criteria that are subjective and create uncertainty about whether a reopener application will be approved.

Regulatory intent

The Draft IM Decisions sets an intent in how some regulatory mechanisms will be applied during a price reset. We note that the implementation of that intent during a price reset will mean a change in approach taken in past resets.

Innovation allowances and incentives: The Draft IM Decision to expand the definition of innovation will allow allowances and incentives to capture the innovation and development needed to develop and incorporate flexibility into an EDB's demand response tool. This includes developing the LV management tools needed to manage the connection of new customer devices and to manage flexibility. This assumes that the allowances and incentives provided at the reset will reflect the scale of the development needed. The past approach to innovation has been conservative in the size of the allowances available and how the risk of investing in innovation is shared between customers and suppliers. The practical application of the expanded definition will mean the Commission taking a more assertive approach to innovation, recognising that the benefits of innovation may not be immediate and that some projects will fail, but a sustained investment in innovation will provide the new capability needed.

Calculation of allowances for flexibility: The Draft IM Decision is to provide allowances for purchasing flexibility rather than to rely on the IRIS to substitute capex and opex budgets. EDBs will not be able to forecast a budget for flexibility payments accurately which will mean that the Commission will need to be comfortable applying step change in opex allowances that will not be precise. Previously, the Commission hasn't allowed step changes for cost that could not be accurately estimated. The practical application of this IM decision will need a change to the Commission past approach to risk and uncertainty in setting opex allowances. New allowances will also be needed for the ongoing operation of the LV management function needed to incorporate flexibility into an EDB's demand response. However, these allowances can be more accurately forecast.

3 Financing and incentivising efficient expenditure during the energy transition

3.1 Financing and incentivising efficient investment

3.1.1 Topic 3a – RAB indexation to inflation

We understand the attractiveness of retaining indexation of the RAB to smooth prices and reduce intergenerational cross-subsidisation. Considered in isolation of a supplier's financeability, indexation of the RAB promotes the purpose of Part 4 in s 52A (as highlighted in the Financing & Incentives Paper).

However, we disagree with the Commission's assessment that because indexing or not indexing the RAB is NPV neutral, suppliers will continue to have incentives to invest (and would therefore promote 52A(1)(a)) – that financeability will not impact the incentive to invest.

The availability of cashflows to fund supplier operations and ability to remain solvent, impacts a supplier's ability to raise additional funding and can change the cost of that funding. In setting allowances for the cost of debt, the Commission assume a credit rating (BBB+) to estimate the debt premium that networks should be able to secure debt funding at. This credit rating assumes a regulatory cashflow that can support the assumed funding structure. If the regulatory cashflows can't support the benchmark credit rating, then EDBs debt costs will be higher than the regulatory allowances provided to fund debt (the network's actual implicit or explicit credit rating will be lower than the benchmark). Equity investors may then have to forgo dividends to service debt, making investing in an EDB less attractive at a time when networks will need to secure more funding to deliver the step change in emissions-related-investment. Inhibiting an EDB's ability to attract new investment will not only impact the provision of distribution services but will also inhibit the ability of customers to access future renewable generation and New Zealand's ability to decarbonise.

Multiple regulatory mechanisms impact financeability and the impact of indexation of the RAB can't be considered in isolation (although it does have a large, if not the largest influence). We believe a standard financeability test should be included in the IMs and applied each price set. This will ensure EDBs are not adversely impacted by cashflow shortfalls to the point they cannot secure funding aligned with the allowances provided. Financeability testing benefits customers by ensuring networks have access to the funding they need and are incentivised to invest. Financeability testing also minimises financing costs over the long term. We discuss the need for a standard financeability test in section 3.1.4.

3.1.2 Topic 3b – Implications for IRIS for cashflow timing

While the Commission's description of cashflow volatility caused by the IRIS in clause 3.109 in the Financing & Incentives Paper are correct (that EDBs can accurately predict those cashflows, they are in the control of the EDB and that EDBs can borrow to manage any cashflow shortfalls) the underlying issue is that volatile cashflows that are complex to manage, disincentivise investment decisions that rely on the IRIS providing the benefits of those decisions. Any decision relying on the IRIS must also include the analysis of the IRIS (which needs speciality expertise) and a cashflow management plan to manage the resulting cashflow.

We also do not think that the wider cost efficiency issues have been solved. A long-term solution still needs to be found that allows opex and capex to be substituted between regulatory periods to incentivise non-wires solutions if they are a more efficient solution to traditional wire solutions. This is discussed in more detail in section 3.2.1 of this submission.

However, we do agree with the Commission that retaining the IRIS is the best solution available to promote cost efficiency *until* a better solution is identified. We believe the focus should now shift to:

- Considering whether to remove some costs from the IRIS or treat costs as a pass-through where cost fluctuations are outside of an EDBs control and the IRIS will not be rewarding or incentivising efficiency (minimising unnecessary cashflow fluctuations). For example, insurance cost fluctuations are largely outside of an EDBs control and should be treated as a passthrough (see section 5.6.1).

- Develop a long-term solution to the opex/capex trade-off between regulatory periods and continue to explore ways of simplifying the IRIS if this shown to be the best long-term solution.

- EDBs to continue to develop better tools to incorporate the IRIS into business decisions.

3.1.2.1 Cashflow timing is best considered in aggregate

We agree that any volatility in cashflows introduced by the IRIS should be considered in aggregate with other cashflows fluctuations which create a difference between an EDBs cash outgoings and overall regulatory cashflow.

This approach will also support testing for financeability and whether any cashflow mismatches impact an EDBs ability to attract investors.

Any significant adjustment to EDBs cashflow should be supported with a financeability test to ensure changes to cashflows and doesn't impact the cost of debt and a network's ability to earn a real return.

3.1.2.2 Understanding of IRIS cashflow timing as a potential barrier to effective cashflow management

We believe that networks should be modelling the cash flow implications of the IRIS. These workings will be included as part of a network's Compliance Statements disclosure and we would support including the impact of the IRIS in the Information Disclosures (**IDs**). Incentives and penalties in response to cost effecting performance is an important part of a network's performance reporting which is currently missing in the IDs.

3.1.3 Topic 3c – New connections volume wash-up mechanism for EDBs on a CPP

We like the concept and intent of a washup mechanism based on standard cost but believe it should be included as an option an EDB could choose to use when making a CPP application. The washup may not always suit the growth characteristics of a network applying for a CPP. For example, most future demand growth will come from existing connections (and not from new connections) in Wellington and new connection growth tends to be reasonably stable. Most demand uncertainty comes from electrification and will impact existing connections. We also think that the new growth that does come from new connections will mostly come from gas conversions (where the news loads will usually be too large to provide from existing connections)[1]. These new connections will vary in size and cost and will make calculating a standard cost reflective of the actual capex spend difficult. Excluding these connections from the washup calculations would mean the remaining capex (driven by population growth) would then be immaterial when offset by capital contributions. A washup calculation-based connections, could add unnecessary complexity and provide little benefit for some networks.

We do see the merits in applying the washup if it was capturing a material portion of capex growth and that growth was uncertain. Rather than being prescriptive about applying a washup mechanism or other tools to reduce the impact of forecast error, the CPP could provide the flexibility for a supplier to propose using the tools as part of their application.

Connection capex is not material

The intention of this mechanism is to avoid penalising or rewarding EDBs for capex forecast differences from changes in the underlying drivers of demand from small connections not captured in reopeners

[1] There are 55,000 residential gas connections on the Wellington network (110MW of new electricity demand) and 50-100MW of new demand expected from commercial connections.

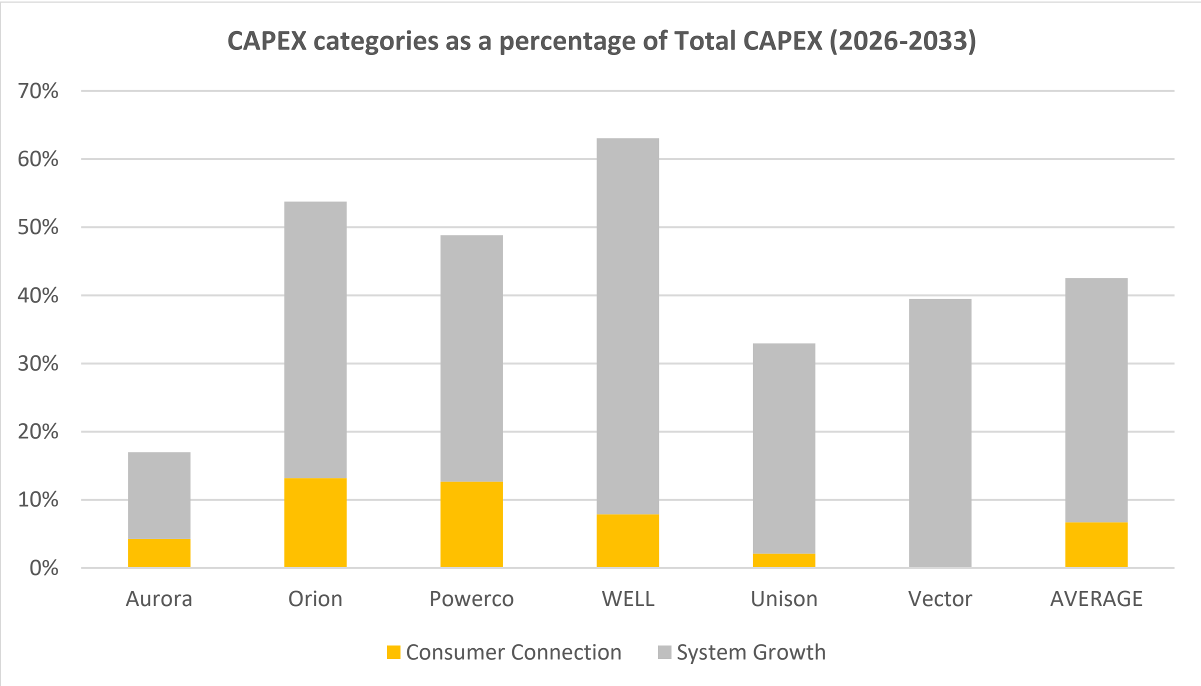
(which are designed for large new connections). Examples of the drivers of this growth are provided as EV uptake or general growth[2]. While there will still be some growth from new connections, the majority of emissions-reduction-related growth is excepted from existing connections. In Wellington we are forecasting 80% of future demand to come from existing customers electrifying their vehicles and gas use.

This is a change in trend from what networks would have historically experienced:

- previously most new demand would have come from new connections;
- demand from existing connections has not changed or has declined over time as electric appliances have become more efficient.

While historically connection capex may have been a significant proportion of total capital expenditure, increasing growth capex to support growth from existing connections will reduce connection capex's proportion of total capex. Figure 2 provides connection and network growth capex for the 2026 to 2033 period.

Figure 2 – connection capex as a proportion of total capex



[2] Section 3.140

More large connections will make it difficult to develop a standard cost

We also think that developing a sensible standard cost may become more difficult as customers transition from gas to electricity and as electricity becomes the primary energy source for new connections. We believe that customer connection sizes and connection cost will become more variable. For a standard cost to promote cost efficiency, it must be reflective of actual cost, or an EDB will be penalised and rewarded for forecast errors or cost variability.

We are in the process of DETA[3] surveying the 150 large gas users in Wellington and early indications are there will be 30MW of new electricity demand from 32 current gas users who have responded to date. Large gas conversions will be by a new or upgraded connection (unlike vehicle electrification, existing commercial and industrial connections are unlikely to be able to support the size of the new electrical loads) which will vary in size and cost depending on their characteristics. While these connections would probably be excluded from the proposed washup mechanism, there will also be the next tier down of current gas users. Connections in Wellington can vary significantly in cost depending on the transformer size and how much trenching is required (trenching being the single largest cost of a connection). The cost variation of a large connection is likely to mean that applying a standard cost could reward or penalise an EDB depending on the characteristics of each connection.

Could the washup mechanism be used to apply to LV reinforcement

We considered whether the washup could be applied to LV reinforcement capex. LV reinforcement is a new requirement driven by consumers exiting fossil fuels from their home energy use in favour of renewable electricity.

While this type of investment would suit a washup (high volumes of individual upgrades and low-cost variability that would suit a standard cost), washing up any capex spend differences would disincentive flexibility (the benefits of deferring capex would be washed up).

Increasing demand from existing connections will impact the capacity of the supporting LV network and on the growth capex relating to LV network reinforcement. LV networks have not been designed to host large devices like EV chargers and the unmanaged penetration of large numbers of EV Chargers will drive the need for more reinforcement of LV network capacity. Our 2023 AMP provided a study

[3] DETA are surveying all major gas users in New Zealand as part of a jointly funded EDB, Transpower and EECA project.

of the impact of the gas transition on 10 LV networks[4]. The study showed that all 10 networks would need reinforcing with more capacity before the end of the transition period.

We considered whether the washup mechanisms could be used to washup any differences in the forecast of when LV reinforcement was required. LV growth capex has similar attributes as small connections in that they are a low value but high-volume programme (we have 4,500 LV networks). We also believe that a reasonably accurate standard cost could be calculated based on the type of asset which has run out of capacity (it would likely to be either a new transformer or larger conductor/cable).

However, washup mechanisms would remove the ability of the IRIS to provide efficiency incentives for finding a more efficient way of providing the additional capacity needed to host EVs and convert gas to electricity. Non-wire flexibility will provide important tools for shifting new demand away from network peaks, deferring investment and reducing the size of future electricity price increases. The washup would eliminate any IRIS incentives from deferring capex using flexibility. It's important that networks are incentives to consider flexibility and we believe applying a washup to this capex class will disincentivises flexibility.

We are piloting different LV constraint models and testing their ability to forecast when LV reinforcements will be needed. The models will set thresholds around when LV networks will need reinforcing to maintain a secure supply. The models will also provide a probabilistic estimate of when the reinforcement is needed. While there will be uncertainty around when individual reinforcement will be needed, we believe high number of upgrades will mean the average spend will be accurate. While the uncertain timing of large HV network reinforcement programmes could have a significant impact of the IRIS and capex availability, variability in high volumes of small projects should average and dilute the impact of forecast error.

3.1.4 Topic 3f – Financeability test in the IMs

Along with the other five large EDBs, WELL has engaged Oxera as topic experts, to provide advice for our response to the Draft IM cost of capital decision. As part of that advice, they also provided advice on financeability. The report has been submitted separately to this submission and is titled "Response to the New Zealand Commerce Commission's draft decision for Part 4 Input Methodologies Review 2023 on the cost of capital". This submission will refer to this report as the 'Oxera Report'

[4] Page 67 of WELL's Asset Management Plan https://www.welectricity.co.nz/disclosures/asset-management-plan/

We disagree with the Commission's decision not to include a financeability test in the IMs. The Oxera report provides the detailed analysis and recommendations supporting this view. This submission summarises the findings of the report and supports the findings with examples from other supporting work. We ask that the Commission refer to the Oxera Report of the full analysis.

The Commission said a financeability isn't needed because 'efficient supplier operating under our benchmark assumptions is very unlikely to face financeability issues' and there would need to be a specific change in operating conditions to result in a situation where a supplier would face difficulties maintaining the benchmark leverage and credit rating'[5]. Instead, financeability issues, or inability to invest, may be caused by company-specific decisions such as poor performance of unregulated business units, excessive dividend payments, or excessive leverage[6]. The Commission does note that it does consider financeability 'where relevant and not inconsistent with promoting the Part 4 purpose' and provides examples of financeability assessments at setting a price path[7].

The Oxera Report outlines how regulatory allowances, including IM decisions, can create financeability issues in suppliers operating efficiently under the regulatory benchmark assumptions i.e. if the timing of cash outflows and inflows is not sufficiently aligned, the company may need to secure a significant amount of finance which may or may not be possible to do on reasonable terms. This is more likely to be problematic in high-growth phases where CAPEX outflows are relatively high, compared to the depreciation allowance. Some EDBs in New Zealand are about to enter a high growth phase as they invest to deliver New Zealand's ERP.

A financeability test that ensures that the regulatory construct provides reasonable cashflows and that networks are adequately funded, explicitly promotes the purpose of Part 4. Without reasonable funding, a supplier will not be incentivised to innovate and invest.

Qxera highlights that while the price/quality path reset is a convenient stage to implement a financeability assessment because cashflow forecast are more likely to be available, it is also important to consider financeability during an IM review because IM's can also impact financeability i.e. "However, by leaving the financeability assessment until DPPs, CPPs or IPPs, the NZCC potentially limits the effectiveness of the test in its role as a cross-check of the sufficiency of the regulatory price

[5] Section 3.292
[6] Section 3.293
[7] Section 3.288.

control package. Moreover, the NZCC limits its options of remedies that it could deploy, should a financeability issue be found[8]".

For this reason, Oxera suggests a provisional test when setting the IMs and a more detailed tests when setting a price path:

1. Undertaking a provisional financeability assessment using cash flow forecasts when reviewing the IMs.
2. A more detailed financeability test using a financial model representative of a benchmark financial structure and forecast cashflows.

We support Oxera's recommendation to undertake a financeability assessment using provisional cash flow forecasts.

The six large EDBs have Commissioned Frontier Economics to assess the impact on cashflows of applying the 10% revenue cap and washup mechanism[9]. This example provides:

1. An example of how provisional cashflows from regulatory Information Disclosures can be used to test financeability.

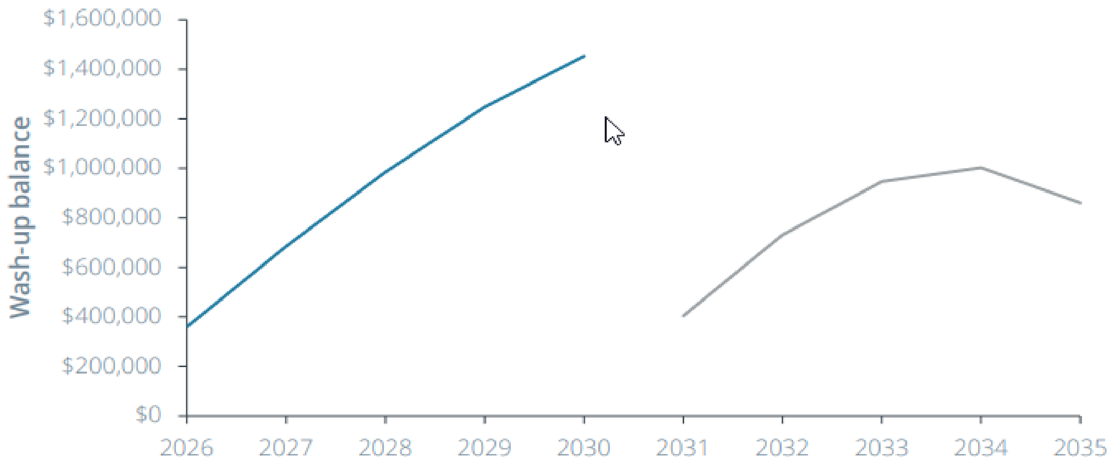
2. An example of where at a regulatory mechanism could create a misalignment of cashflows to the point an EDB could have financeability issues and the cost of debt allowances will not be sufficient to cover its funding costs.

3. An example of IM mechanism that can impact financeability.

The Frontier Report found that a combination of high inflation (increasing the RAB) increasing capex and increasing WACC creates a washup amount large enough to defer the recovery of EDBs' efficient costs over multiple periods. Figure 3 provides a graph from the Frontier Report showing the cumulative washup balance of the six large distribution networks over the next two DPP periods. The modelling and the graph show that nearly $1.5b of revenue could be left unrecovered by the end of DPP4. While much of that revenue could be recovered over DPP5, more than $860m would be unrecovered by the end of DPP5.

[8] Section 8.7 of the Oxera Report
[9] Submitted to the Draft IM Decision Consultation, Frontier Economics, 'A review of the limit on EDB price increases'.

Figure 3 – Cumulative wash-up balance ($000)



Source: Frontier Economics analysis of EDB data

A financeability test shouldn't be applied subjectively

We disagree that the Commission doesn't need to apply a formal financeability test in the IMs because they can already have regard to financeability if they judge it's needed. We believe an objective application of the financeability test is needed so as to consistently and objectively ensure networks can practically fund their investment requirements and the debt allowances needed to do this are adequate. As shown in the example above, cashflow issues can be created from the continued application of existing regulatory mechanisms because of changing operating conditions.

We think the financeability tests should be applied as part of the IMs to ensure that the IMs and the price setting both maintain financeability. Including financeability as an IM will ensure the test is consistently considered.

3.2 Incentivising efficient expenditure for EDBs and Transpower

3.2.1 Topic 4a – Maintain the current expenditure incentive schemes as tools for mitigating capex bias

We agree with the Draft IM Decision narrative that it will be important for EDBs to be able to substitute capex and opex going forward as non-wire solution provide alternatives to building traditional capacity in response to emissions-reduction-related demand increases (the non-wire solutions enabling a network to defer when expensive wire solutions are built). That substitution should incentivise whatever is the most effecting solution – what solution (or combination of solutions) provides the lowest long-terms cost. We also agree that the IRIS does not allow opex/capex substitution across regulatory periods, an issue which is well defined in Attachment C to the Financing & Incentivising Paper.

The Draft IM Decision should only be a short term solution

We don't think a long-term solution has been found to the opex/capex substitution issue and more work is needed to solve the issue. We disagree with relying on allowances to fund flexibility is a viable long-term solution because of the difficulty of accurately forecast when flexibility will be a better solution to traditional wire solutions and the difficulty in forecasting how much customers will pay for those services. Inaccurate forecasts do not provide incentives for networks to make efficient cost choices (the difficulty in forecasts flexibility allowances is discussed below).

We agree that the proposed Draft IM Decision of a combination of retaining the IRIS and introducing allowances and incentives for flexibility (including allowances and incentives to develop LV Management needed for EDB's to incorporate flexibility) is the best combination of options identified. In the short term, these would help to incentivise flexibility and support their development.

However, this assumes that the Commission will be comfortable providing allowances for expenditure that is difficult to forecast accurately and for which networks will not be able to provide precise budgets for. This will require a different approach to past DPP resets which has rejected any opex step changes that were uncertain. The DPP3 final decision was not to apply any step changes in opex. The Commission said "we have not made any step changes in response to submissions. Submissions were largely qualitative, so we lacked information to show if step changes proposed by submitters met the significance or robustly verifiable criteria[10]".

A post IM work programme

However, we believe the draft decision is only a stop gap that needs correcting. Given the importance flexibility will play in EDBs being able to deliver New Zealand ERP, and that we do not believe the Draft IMs decision solves the opex/capex substitution issue, we would support a follow-up work stream in parallel to the DPP4 price reset. Alternatively, the work programme could be implemented during DPP4. As shown by IM changes made to support DPP decisions, there is a precedent for making on-going refinements to the IMS.

We note the Commission commented that a totex regime does not address the issue of opex/capex trade-offs across regulatory periods[11]. We would not support implementing a totex regime if it does not solve this issue. However, there are many variations to the totex regime and a variation could

[10] Section A58 of the Default price-quality paths for electricity distribution businesses from 1 April 2020 – Final decision
[11] Section 4.84

provide a solution. We would support exploring a totex regime further to test if there are variations which would solve the opex/capex substitution issue.

Foresting allowances for flexibility – why the effective substitution of opex and capex is important

The ability to substitute capex and opex will be important due to the difficulty in being able to forecast opex allowances for purchasing flexibility or non-wire solutions. Flexibility is in the early stages of development and EDBs do not have the knowledge to accurate forecast opex allowances to fund those services. Even when flexibility matures, we believe that it will still be difficult to forecast opex allowances with any accuracy because it will be difficult to forecast the inputs into the allowance forecast:

- How much EDBs and other buyers will pay for flexibility service (noting that EDBs will be competing with other flexibility buyers)
- What sort of demand response a flexibility service will provide, and for how long a capex investment can be delayed for (before demand increases exceed the additional capacity headroom flexibility can provide). This will depend on how fast the market matures and whether all of the components required to provide flexibility at the scale needed are in place[12].
- What assets will be constrained in the future and what assets will a non-wire solution be a viable alternative for. Network constraints will be a result of peak demand increases which are influenced by many external factors like EV uptake, Government emissions-related incentives or penalties, Government policy changes (like whether to continue with gas), technology changes impacting appliance prices etc.
- A networks visibility of the LV network and how efficiently the LV management tools allow a network to call on flexibility into their demand management (noting networks still need to develop this capability).

If an allowance can't be forecast accurately, then any application of the IRIS (or other cost efficiency incentives) would be rewarding forecast errors and not cost saving efficiencies. The ability to substitute capex and opex allowances provides a more accurate way of funding flexibility. A network can continue to forecast when network reinforcement or growth capex is needed using traditional

[12] Our EV Connect Roadmap highlights the many new functions that need to be developed across the flexibility supply change to allow flexibility to be offered https://www.welectricity.co.nz/major-projects/ev-connect/.

solutions, providing a benchmark cost of providing new capacity. A network can then substitute the capex allowances for opex if its more efficient to do so. Those benefits are then shared with the supplier (incentivising non-wire solutions if they are more efficient) and the customer.

3.2.2 Topic 4b – Maintain the current incentive mechanisms as they best balance considerations of effectiveness and understandability

We agree and support the Draft IM Decision to maintain the IRIS incentive mechanism in the short term and the current equalized opex and capex incentives rates.

As discussed in section 3.2.1, the opex/capex substitution issue still needs solving. We support retaining the IRIS while a long-term solution is developed.

3.2.3 Topic 4c – Adjust IRIS allowances for inflation

We support the Draft IM Decision to calculate the opex and capex incentive amounts based on IRIS allowances (adjusted for actual CPI) compared with actual expenditure. This will reduce the risk that EDBs are rewarded or penalised for inflation forecast errors in the IRIS calculation which are outside of the network’s control.

We also support updating the opex and capex IRIS allowances based on CPI because it ensures consistency with the revenue inflation wash-up. We think the differences between washing up with the inflation measures used to set the IRIS and using CPI will probably be immaterial and keeping consistency with the revenue inflation washup is more important.

3.2.4 Topic 4d – Maintain our approach to setting incentive rates

We support retaining the current approach for setting the incentive rate for the reasons provided in the Financing & Incentives Paper.

3.2.5 Topic 4e – Not to exclude specific expenditure categories from IRIS

We disagree with the Draft Decision to not allow specific expenditure categories to be excluded from the IRIS. We think the alternative options explored, specifically providing the option of allowing for the exclusion of some expenditure categories from IRIS at a reset, would provide the Commission with the ability to exclude costs that were it’s difficult to forecast an accurate allowance. This would be useful where a DPP provides an allowance based on uncertain forecasting assumptions and there is a high probability that the actual cost will be different. Removing the forecast from the IRIS would mean an EDB wasn’t penalised or rewarded for forecast errors.

Examples of the types of costs where this would be useful could be:

- Allowances for non-wire solutions that are very difficult to forecast and any variations to actual costs are likely to be a result of forecast error and not efficient investment decisions.
- Uncertain capex growth forecasts where there is significant uncertainty in the underlying demand drivers.

We think this mechanism could be especially useful for uncertain ERP related capex where the risk of underinvestment significantly outweighs the benefits of applying cost saving incentives to costs which are difficult to accurately forecast.

Treatment

Rather than treating as a passthrough, we think the cost could be left in the allowances and removed from the IRIS calculation – adjusting the IRIS from the IRIS opex and removing them from actual costs when calculating the IRIS impact.

A similar adjustment is already made for the right-of-use assets. We don't think this would make the DPP reset much more complex as a similar adjustment is already made.

Pass-through or exclude from IRIS

We do also think there is also a place for passing some costs through as a pass-through. We think the decision criteria should be on the characteristics of the allowance and the cost.

Figure 4 – decision criteria for applying different regulatory mechanisms

Mechanisms	Characteristic	Explanation	Example
Pass through	The network has little control over incurring the cost or cost fluctuations.	Pass through to reflect that there is no benefit in incentivising an efficient procurement because the underlying drivers of cost fluctuations are outside of the supplier's control.	Insurance where annual uplifts are dependent on the global insurance market.
Exclude from IRIS	Forecasting an allowance for the cost is difficult and there is likely to be forecast error and where there is a high	Exclude from IRIS so as not to penalise or reward for forecast errors.	Flexibility allowances which are difficult to forecast.

Mechanisms	Characteristic	Explanation	Example
	cost of under investment.		

3.3 Inflation risk

3.3.1 Topic 5a – Method for forecasting inflation

We disagree with the proposed approach of using a mechanical glide path which is shown to return to the long-term average quicker than past inflation movements. We think that a market expectation of inflation forecast should be used to inform the glide path period that the RBNZ forecast doesn't cover. While we recognise the weaknesses in using this as a primary forecasting tool, we think a market expectation of inflation would provide a more accurate prediction of the later forecast years that the RBNZ does provide, than simply applying linear glide path assumption.

We also note, that while the Draft IM Decision to continue to use the RBNZ forecast as the primary forecast method is the best of the options identified, the forecast is still inaccurate (as shown by Vector in their submission to the IM Issues Consultation[13]). We believe that more work needs to be done on exploring better forecast methods or methods of removing the need to forecast inflation. We don't think this issue should be left to the next IM review – it's a known issue that still needs to be resolved. We would support a residual work programme that follows on from the final IM decision.

3.3.2 Topic 5b – Inflation risk allocation and compensation

3.3.2.1 Finding 1: exclude debt costs from annual revenue inflation washup

On the surface it appears to be an effective way of removing the inflation forecast error from the debt allowances. We support changes that minimise forecast errors from the regulatory allowances.

However, the proposed change is unique and has not been applied in any other regulatory jurisdiction. The consultation timeframe hasn't provided the time needed for a detailed check of how the mechanism will work in different scenarios. This solution was also not considered as part of the issues discovery phase of the IM review and stakeholders haven't been given the opportunity for any early testing. The initial modelling from other members, the ENA and Oxera indicates that it could create cashflow volatility. Advice from Oxera is the illustrative model isn't clear on how all components will be applied and that it relied on inputs from the price path setting process. We believe more

[13] Page 21, https://comcom.govt.nz/__data/assets/pdf_file/0022/288022/Vector-Submission-on-the-Process-and-Issues-paper-11-July-2022.pdf

comprehensive testing is needed because the methodology hasn't been used before. We recommend that another workstream is started in parallel to the DPP4 reset to test the impact on cashflows. This workstream should also consider the other options to solve the debt issue in case they are better.

3.3.2.2 Finding 2: We do not wash-up revenue for inflation in the first year of a regulatory period

We strongly support this change. It aligns the treatment of inflation with the rest of the regulatory period and also ensures the transition between a DPP and CPP is not exposed to additional inflation forecast errors.

WELL moved from our CPP directly to year 2 of the DPP3 in April 2021, 15 months after inflation was set. Not being able to washup our first year on the DPP3 (which was DPP3 year 2) equated to $4.5m (~4.9% of our annual allowance) in inflationary cost increases we could not adjust our allowances by and had to fund by cost-saving and deferring work programmes.

Removing or minimising inflation forecast errors improves regulatory certainty and avoids windfall losses or gains. This includes improving regulatory certainty of the transitioning between price paths and helps reduce the risk of making a CPP application.

3.4 Innovation incentives for EDBs and Transpower

3.4.1 6b: Encouraging innovation and non-traditional solutions

As highlighted in our Submission to the IM Issues Paper[14], EDBs will need allowances to support the development of flexibility of the scale needed to provide a viable alternative to traditional wire solutions. EDBs will also need to develop their own processes and functions to incorporate flexibility into their LV management and demand response. These are not trivial new capabilities and will need substantial investment in resources, time, tools and funding. Our current innovation projects are showing that the implementation costs are material with the cost of data, software, expert advice and the expected flexibility purchase costs are adding to more than the existing allowances.

Other judications have also shown the level of investment needed to develop flexibility. The UK electricity regulator initially provided a £500m fund to try out new technology, operating and commercial arrangements and then moved to an innovation fund of up to £81m p.a. Figure 5 provides the actual funding awarded for distribution system operator (DSO) related innovation projects in the

[14] Wellington Electricity's submission to Part 4 Input Methodologies Review 2023 – Process and Issues paper, Case study 3

UK up until 2019. The figure is from the *'Innovation Mapping to Identify Distribution System Operation Gaps – Closedown Report'* produced by the Energy Networks Association in the UK[15].

Figure 5 – Flexibility related innovation spend in the UK.

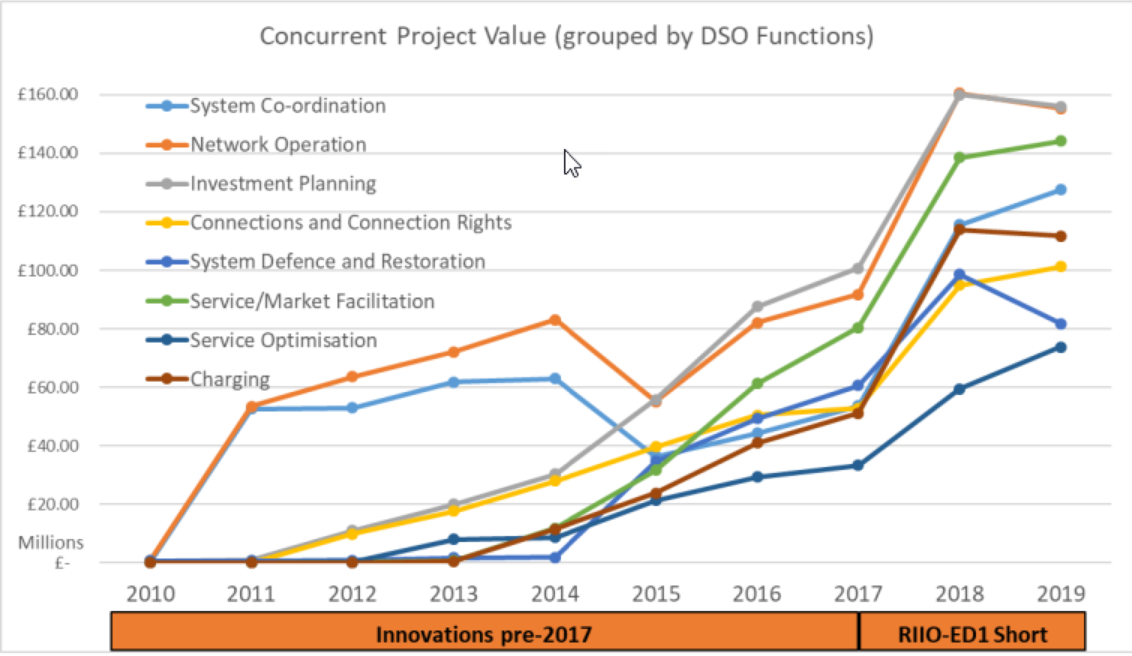


Figure 10 **Value of DSO Innovation Activities Running Concurrently up to 2019 by DSO Functions**

Our concern is the general approach of price/quality regulation towards innovation and supporting networks to develop the new capability to support flexibility, has been passive. Currently, the small innovation allowance that is retrospectively approved by the Commission means that the majority of the risk of innovating falls on the supplier. Currently, suppliers have to fund any additional funding above the maximum allowance and have to fund 50% of the total cost. It is likely to take years for flexibility to be developed to the scale needed to benefit EDBs. Until then, EDBs bear the majority of the cost for no benefit. The current structure disincentives EDBs to innovate.

Given the value of flexibility to customers, both in terms of price and maintaining supply security[16], we think it is important that customers also share in the risk. The approach taken in the last DPP reset appeared to be to 'start small' and let the approach develop over time, rather than setting allowance levels that aligned with what businesses in a competitive environment invests, develop requirements or in line with other jurisdictions. In its Draft DPP3 Decision, the Commission accepted there was

[15] https://www.energynetworks.org/industry-hub/resource-library/on19-ws3-innovation-mapping-to-identify-distribution-system-operation-gaps.pdf
[16] Wellington Electricity's submission to Part 4 Input Methodologies Review 2023 – Process and Issues paper, Case study 2

evidence of the industry underinvesting in innovation when compared to other sectors but still set a modest innovation allowance[17][18].

Part 4, Section 54Q of the Act requires that the Commission must promote incentives, and must avoid imposing disincentives, for suppliers of electricity lines services to invest in energy efficiency and demand side management, and to reduce energy losses, when applying this Part in relation to electricity lines services.

We believe that for the Commission to meet its Part 4 obligations it must be more active in promoting innovation to support the development of demand side response, visibility and management of new demand and flexibility mechanisms. Networks need access to levels of funding in proportion of the costs to develop LV management and to develop and procure flexibility. Networks have already invested significant resources into exploring flexibility – all of which has been found from savings and from other funding sources. We recognise that the IMs set the scope for applying innovation to a reset and do not set the actual allowance levels and supporting incentives. However, we ask that the overall approach taking towards innovation changes to support networks develop the ability to use flexibility and other tools and capability needed to deliver the ERP – that the Commission move from a passive approach to innovation to actively supporting networks.

3.4.1.1 Expanding the Definition of Innovation

We support the change to the IM's definition of innovation. The expanded definition will allow the DPP reset to consider a range of different mechanisms. Specifically, this could include providing incentives for networks to invest in flexibility or allowances for purchasing flexibility and to develop the LV Management tools to incorporate flexibility into their demand response. The expanded definition would also provide incentivised to use flexibility while services are still being developed to the scale needed for them to be an economically viable wire alternative.

The expanded definition will also capture the flexibility development phase, the development of the LV management tools needed for EDBs to use flexibility and the co-development (with flexibility providers) of services themselves, that takes working prototypes and scales those services to the mass market. As noted in the Financing & Incentives Paper, this isn't strictly innovation and would not have been captured in the previous definition. This is an important change that will allow EDBs to support

[17] Section 4.54 Default price-quality paths for electricity distribution businesses from 1 April 2020 – Draft decision
[18] Section F14 Default price-quality paths for electricity distribution businesses from 1 April 2020 – final decision

others in the flexibility supply chain by providing funding to purchase flexibility which can then be used seed the wider value stack and support flexibility providers to develop their part of the supply chain.

While setting innovation incentives and allowances is not within the scope of the IMs, we ask that the Commission carry on the intent of the proposed IM changes and provide suppliers with the funds needed to develop flexibility and the tools to incorporate those services into their asset management practices. Other judications have supported flexibility with funded projects and incentives in line with the size of the development programmes with learning and benefits shared across industry participants. They are now rewarded with flexibility at a scale that can provide a viable wire alternative and their customers are benefiting from lower prices.

3.5 Effectiveness improvements to revenue path wash-up mechanism

We support changes that simplify the washup calculation, assuming the washup mechanism works as expected and doesn't penalise or reward customers or EDBs inadvertently (i.e. has a NPV=0 effect).

The ENA have provided a detailed analysis of the washup calculation on behalf of its members. Our submission is based on their analysis and recommendations. We note the difficulties in testing the mechanism as the price reset will determine some of the inputs into the calculation. The ENA have provided the results of their analysis in their submission, including drafting suggestions.

In summary, in line with the ENA's submission:

- We support the washup approach which tracks balances, drawdowns and time value of money adjustments;
- We support clarifying the wash-up balance from the previous year carry forward when transitioning from one price path to the next;
- Our preferred approach is a smooth transition of the wash-up balance between DPP3 and DPP4, which is consistent with promoting regulatory certainty and managing revenue and cashflow volatility.
- We support the option for EDBs to drawdown the wash-up balance early subject to the revenue smoothing limits. This mechanism should also be available in years 1 and 2 of DPP4.
- We do not support the proposal for the Commission to specify the pace of drawdown of a wash-up balance within a regulatory period. This is unnecessary given the compliance limit,

the revenue smoothing limit and the cap on the accelerated wash-up. EDBs are best placed to manage cashflow.

- We note the need for more clarification around the purpose of the purpose of the base wash-up drawdown and what criteria the Commission will apply when determining the value of the drawdown for each EDB. The Draft IM Decision does not provide enough information to provide informed feedback. The ENA submission also outlines concerns that this mechanism could come into conflict with the intent of the accelerated wash-up drawdown mechanism.

4 Cost of capital

Along with the other five large EDBs, WELL has engaged Oxera as a topic expert, to respond on our behalf to the Draft IM cost of capital decision. The report has been submitted separately to this submission and is titled "*Response to the New Zealand Commerce Commission's draft decision for Part 4 Input Methodologies Review 2023 on the cost of capital*". This submission will refer to this report as the '*Oxera Report'*. This submission only summarises the Oxera findings and recommendations. The full report provides the evidence supporting the recommendations.

Oxera also provided a submission to the IM Issues Consultation which his published on the Commissions website[19]. This submission provides valuable supporting analysis that the Oxera Report refers back to – this submission will call that report the 'Oxera Issues Paper'.

[19] https://comcom.govt.nz/__data/assets/pdf_file/0024/318624/Part-4-IM-Review-2023-Draft-decision-Cost-of-capital-topic-paper-14-June-2023.pdf

4.1 Cost of debt

The Draft IM Decisions estimation of the risk-free rate is not supported by the evidence, specifically, the term of the government bonds do not have to match the length of the regulatory period and a longer terms tenors provide a better estimation of debt costs. There is also a strong case to add a convenience yield premium and by not doing do underestimates the risk-free rate.

The Draft IM Decisions approach to the debt premium exposes networks to uncertainty, and a higher term credit spread differential is supported by the evidence. Figure 6 summarises our response and recommendations to the components of the cost of debt.

Figure 6 – Cost of debt

Component	Draft Decision	Findings	Recommendation
Risk free rate			
Convenience yield premium	Not to add a convenience yield premium.	The evidence provided in the Oxera Issues Report provides a strong theoretical case for including a convenience yield premium. The evidence provided in response to the Commissions concerns around difficulties in estimating a convenience yield shows that it can be readily estimated and should be included in the WACC calculation.	Include convenience yield premium
Bond rate term	Align bond rate terms with length of regulatory period	We have reviewed Dr Lally's modelling and concluded that it does not prove that the term has to match the length of the regulatory period.	Use bond rates longer than 5 years, reflecting the long-term nature of the assets being financed.
Debt premium and term credit spread difference			

safer together

Component	Draft Decision	Findings	Recommendation
The trailing average approach to the debt premium	Not to introduce a term credit spread – while the Commission recognise it would provide better alignment with actual debt costs, a change would provide insufficient benefits and operational complexity.	Oxera has evaluated Dr Lally's assessment and found that bringing the assumptions of his modelling more into line with market conditions makes the case for the trailing average significantly stronger.	Apply a training average as it provides a better estimation of actual debt costs.
The term credit spread difference	Estimated at 7.5 bp	We find that the NZCC's own evidence supports a higher TCSD at 10.2bps instead of 7.5bps if the NZCC does not subjectively exclude the COVID-19 period from the estimation window, and if it avoids double-counting a category of the bonds within its sample. In addition, we do not find the ten-year term cap to be well justified.	Estimated at 10.2 bp

4.2 Cost of equity

There are more robust approaches to calculating the tax-adjusted market risk premium (TAMRP). The more robust estimation methodologies that underpin the TAMRP range point to an estimate that is closer to 7.5% than to the 7.0% proposed by the Commission. The figure of 7.5% is also consistent with the broker estimates.

The asset beta allowance underfunds the networks and is a deviation from the Commission principles-based approach to the review. Compared with the Commission's preferred asset beta estimate of 0.35 for energy networks, an average of daily, weekly and four-weekly estimates for the last two five-year periods is 0.37, while the 75th percentile of the range (which is consistent with the percentile that the Commission's chooses for asset betas in its Draft IM Decision within its proposed range) of these estimates is 0.39.

Figure 7 summarises our response and recommendations for the components of the cost of equity.

Figure 7 – Cost of equity

Component	Draft Decision	Findings	Recommendation
Tax-adjusted market risk premium (TAMRP) – an assessment of the evidence used to calculate a TAMRP of 7%, concluded that some of the evidence is not sufficiently reliable. We note that the Commission have not commented on the Oxera's Issues Report which originally presented these recommendations. We recommended a TAMRP of 7.5%, which is also inline with an updated brokers estimate.			
Dividend growth model (DGM)	DGM and survey resulted used in the estimation of the TAMRP.	Modelling is provided that demonstrates why we do not find DGM to be a robust approach to estimating the TAMRP. We have also previously explained the limitations of using survey-based evidence to assess the reasonable level of the TAMRP (page 27 of the Oxera Issues Report).	We recommend that the Commission does not put weight on the results from the DGM, and the survey-based results, in its estimation of the TAMRP.
The Siegel models	Weighted Siegel I model and Siegel II model inputs used in the TAMRP calculation.	We recommend placing more weight on the evidence from the Siegel II model and less on the evidence from the Siegel I model, due to the former's more reliable assumptions about the relationship between the RFR and the market risk premium. This means that a more reliable TAMRP estimate would be anchored on the evidence from the Ibbotson model and a weighted Siegel model that reduces reliance on the Siegel I specification.	Reduce the weighting applied to the Siegel I model and increase the weighting applied to the more reliable Siegel II model.
Broker estimates	Brokers estimates of 7%	Based on the evidence that we have collated from the public domain, we have found that the TAMRP estimates by investment banks selected by the Commission do not fully represent the view of these institutions. As a result, the data relied upon by the Commission does not appear to be robust.	Use updated broker estimates which provides a mean of 7.25% and a medium of 7.5%.
Asset beta			

Component	Draft Decision	Findings	Recommendation
Frequency of returns data	Daily betas excluded from the data set used to calculate the asset beta.	The key concern typically associated with daily beta estimates is stock illiquidity, which is mitigated in this instance given that the Commission applies liquidity filters. We also show that the average standard errors of individual comparators' asset betas are the lowest for daily asset betas, which shows that from the point of view of statistical significance, there is no reason to exclude daily betas from the Commission assessment.	We recommend that the Commission adds daily beta estimates to the set of evidence that it uses to set the allowed asset beta.
Treatment of the COVID-19 period	Exclude data from the COVID-19 pandemic period.	We consider that the beta estimates affected by the COVID-19 pandemic provide valuable information about the companies' risks, in the same way as any other event causing market volatility would. Accordingly, we see no reason for the COVID-19 pandemic period to be treated differently and for it to lead to the change in the NZCC's approach as part of this IM review. We find the NZCC's approach concerning, as it introduces non-justified non-replicable methodological steps and, in so doing, reduces the stability and predictability of the regulatory regime.	Include data from the COVID-19 pandemic period as it provides valuable information about the companies' risks.
Reasonableness check	Asset beta of 0.35	Compared with the NZCC's preferred asset beta estimate of 0.35 for energy networks, an average of daily, weekly and four-weekly estimates for the last two five-year periods is 0.37, while the 75th percentile of the range (which is consistent with the percentile that the NZCC chooses for asset betas in its DD within its proposed range) of these estimates is 0.39.	Review inputs as the proposed beta is lower than the comparatives

4.3 WACC Percentile

The Oxera report analyses the Commission's reasoning for reducing the WACC percentile for EDBs from the 67th to the 65th percentile and finds that the 67th percentile was already at the lower end of the optimal range. Insufficient investment incentives might risk delaying the energy transition, which would have significant asymmetric effects in terms of social outcomes that are additional to those captured in the loss analysis framework.

The main reasons why the Oxera reports find the estimation to be low are:

1. The Commission uses an Oxera estimate based on outage costs of NZ$1bn, which actually represents the lower bound of the range that we considered in the previous Oxera Issues Report. As this lower bound is then used to form a new range, this might underestimate the impact of our derived figures. Using the mid-point of the range that we considered (NZ$1.45bn) results in an optimal estimate of between 61% and 78%, which suggests a mid-point above the 67th percentile (even without removing the tax uplift—see the next point).
2. The Commission's WACC uplift model adjusts the regulated asset base (RAB) by 1 minus the corporate tax rate. We consider that taxes are actually redistributed to society, resulting in a welfare benefit. We therefore consider that a full tax uplift is not appropriate. Removing the tax adjustments results in a range of 60% to 77%, i.e. a mid-point above the 67th percentile under the Commissions and Oxera's most conservative cost of outages assumption of $1bn.

Overall, our analysis suggests that the 67th percentile is already conservative, and therefore a reduction to the 65th percentile is not appropriate.

4.4 Reasonableness check

Many factors need to be accounted for when interpreting RAB multiples and the conclusions are sensitive to the assumptions. Therefore, Oxera does not consider RAB multiples to be a reliable check of the reasonableness of the WACC allowance.

Oxera suggests using the asset risk premium–debt risk premium (ARP–DRP) framework as an alternative reasonableness check of the cost of equity allowance. The cross-check shows that the risk premium, embedded in the cost of equity, if adjusted for the effect of leverage (ARP), is not sufficiently high relative to the DRP, which suggests that the overall allowance for the cost of equity should be higher. The alterative cross check supports the recommended adjustments to the cost of equity calculation.

4.5 Equity issuance costs

The changing operating environment means that EDBs are likely to need to made a step change in investment in response to the government's ERP. It's also likely that a network will need additional equity to maintain its gearing at a level consistent to a BBB+ credit rating to maintain the ability to fund the cost of debt from allowances. Retained profits may not always be sufficient to finance growth and not paying dividends for a long period of time is not sustainable if a network had to attract new investment. If a network needs additional equity financing then there will be a cost to securing that equity. Providing an allowance for equity issuance costs, combined with a regulatory assumption that dividend payments will be made, aligns with the purpose of Part 4, specifically incentivising a supplier to invest.

We recommend developing a benchmark cashflow model that can be used to test whether networks will have to increase their equity funding as they invest in new capacity to deliver New Zealand ERP. This model could also be used to test for financeability. Network AMP disclosures could provide the future cashflows needed to develop this model.

5 CPP and in-period adjustments

We note the Commission's decision to maintain the DPP/CPP price path choices for EDBs and note that legislative changes would be needed to introduce an IPP or another type of price-quality path. We also note that the CPP best suites discrete work programmes that can be delivered within a single regulatory period – a CPP application and the resulting price/quality path is just for the 3-5 year regulatory period. After that another application for a CPP must be made or the EDB will move back to a DPP.

However, many network emissions reduction-related work programmes will require a sustained step change in investment across multiple regulatory periods. Our submission to the IM Issues Consultation analysed our 30-year investment programme, characterising that investment[20] as being a material step change from historic averages and sustained across multiple regulatory periods. The analysis also showed that while the need for the investment was highly probable, the timing of when to invest could change due to uncertain and changing investment drivers.

Rather than continue to submit multiple CPP applications and incur the high costs of making one-off funding requests, we think an IPP, like that used for networks in Australia, the UK and Transpower, would now be more appropriate. Using an IPP for networks with large sustain investment profiles could:

- Make it easier to shift investment packages between regulatory periods and potentially remove the need to reassess those investments, reducing regulatory costs.
- Include a longer-term/high-level investment programme to guide the movement of investment packages between regulatory periods.
- Allow the application process to be streamlined, reducing regulatory costs.

We understand that an IPP would require legislative changes to the Commerce Act 1986 and changes to the Act is the Ministry of Business, Innovation, and Employment (**MBIE**) responsibility. However, endorsement from the Commission would be an important step to encourage MBIE to include consideration of an IPP on to their work programme. We plan to address this with MBIE shortly.

[20] Case studies 4 and 5 of our submission to the Part 4 Input Methodologies Review 2023 – Process and Issues paper.

5.1 Whether changes to CPP IMs are necessary

5.1.1 CPP streamlining

We understand and agree with the need for a higher level of scrutiny for a CPP, reflecting the impact on customer prices, and potentially quality of supply. We also understand and agree that there needs to be an element of customisation of that scrutiny because of the unique nature of CPP work programmes. However, we believe there are scrutiny and verification elements that can be standardised. This will help networks align their application with, or account for, the Commission's expectations around what's a verified cost input. EDBs should be confident that their applications are providing enough information for the Commission and its agents to make a sound application decision, while not wasting money providing unnecessary information.

Our observation of past CPP application reviews is that they appear to be conservative and where there is uncertainty or not enough evidence has been provided, allowances are removed. We expect that more networks will require a step change in investment to meet emissions reduction-related demand increases and CPP applications will be made with less precision because of the nature of future demand growth (the drivers of demand being uncertain). EDBs will need regulatory certainty to attract the additional investment they will need to fund their future investment profiles. That regulatory certainty includes being able to construct a CPP application that provides the Commission confidence that the approved allowance and supporting incentives will provide customers with the new capacity they need to electrify fossil fuel use while also maintaining a secure electricity supply.

The Commission can improve regulatory certainty by providing more clarity about what EDBs should provide in their CPP applications to support a positive decision. We believe that this clarity can be provided by guidelines supporting the IMs, rather than changes to the IMs themselves.

5.1.1.1 Supporting guidance to ensure CPP applications support a robust decision

In CPP the application process could be supported with guidelines and advice about what information should be included in an application. We believe the application process could be improved if guidelines where provide on:

- Specific verification approaches including benchmarking. EDBs could then ensure that the applications were based on cost expectations that were aligned with the Commission.
- Expectations about customer consultations include the level of consultation and how detailed Commission what feedback provided on.

- The extent the Commission wants a price/quality trade-off modeled and developed as options.

The guidelines could be developed and refined over time with each application.

We also think it would be useful if a supplier could check that the proposed context and coverage of an application is what the Commission expect to see in a CPP application. This would help ensure suppliers were focusing their resources on the right thing.

The proposed supporting guidelines and the opportunity to confirm the content of an application, supports the purpose of Part 4 by supporting a network to secure the allowances needed to invest, and by directing an application to reflect an efficient cost. The changes would also support the purpose of the IMs by improving regulatory certainty.

5.1.2 Single issue CPP

We agree that with the DPP reopener adjustments of being able to include opex costs and removing the upper $30m value limit, DPP reopeners should be able to meet **some** single-issue CPP scenarios.

However, as stated in the In-Period Adjustment Paper, our submission to the IM Issues Paper highlighted that the use of reopeners is limited to smaller projects that can be planned and commissioned before the end of the regulatory period. The current reopener framework will not capture investments with longer delivery programmes that need to be started and capex spend in this regulatory period, but where the assets will not be commissioned until the next period. For these projects, a network may have to delay the project for 2-3 years until allowances are awarded in the next regulatory period (either in the DPP or by reopening the next regulatory period), negating the intent of the reopener mechanism of being able to better match allowances with unexpected investments. We are experiencing this in practice and it's likely we will have to delay customers connecting until DPP4. This issue is discussed in more detail in section 5.2.9 of this submission.

If the Draft IM Decision is not planning on amending the reopeners to allow programmes to span regulatory periods, a single-issue CPP may still be the best mechanism to capture larger projects that fall towards the end of the regulatory period. The regulatory framework should support customers to connect to the electricity networks when they need to, supporting their decarbonisation activities. Currently, the opposite is true, the reopeners are forcing customers to adjust their programs to fit with the artificial timeframes of the regulatory framework.

5.2 Improving the price-quality path reopener processes

5.2.1 Clarify and examples of what information is needed in an application

We agree with the requirement of suppliers to provide sufficient information to enable the Commission to assess whether a reopener event has occurred and whether a price-quality path should be amended. As outlined in the In-Period Adjustment Paper, without this there could be back-and-forth information requests, adding further uncertainty to the application and project timelines.

For this to be successful, it will be important to have examples and guidelines clearly outlining what information is required to satisfy this clause. Our experience in drafting a number of different reopeners is clear information requirements speed up the application process and also provides a level of confidence that the circumstances of the reopener will fit the reopener criteria (it becomes a self-check). We submitted an initial draft application for our first application as a check we were providing the correct information. We then used this as a template for future applications.

5.2.2 Considerations the Commission must have regard to

We have concerns that some of the different considerations the Commission must have regard to in making a reopener decision, will make reopener decisions more subjective, and the outcomes less certain (counter to Section 52R of the Act). It's important that a supplier making a reopener application that has met the criteria, has the confidence of the decision outcome so they can plan and reprioritise their work programmes as needed. More importantly, it's important that a customer who will also be basing their project planning on the expected outcome of a reopener, has confidence in the decision outcome.

Draft IM clauses which we think need additional care when considering because their assessment might have level of subjectivity are:

4.5.13 (1) (a) the impact of the reopener event given the relevant circumstances, including both positive and negative effects, on the EDB's costs, revenues, and quality outcomes;

4.5.13 (1) (c) (i) whether the action required to respond to the reopener event's adverse consequences can be delayed until a future regulatory period;

4.5.13 (1) (c) (iii) whether the EDB's planned capex and opex for the remainder of the regulatory period have been appropriately reviewed and reprioritised;

We suggest that these subjective criteria are removed from the IMs. The risk of a network not being provided allowances when they need them and underinvesting is greater than the potential cost savings that are achieved by not awarding a customer endorsed reopener application and forcing a network to deliver the project within their allowances.

If these subjective criteria remain the IMs, then they should be more objective in their drafting so that suppliers and customers can confidently make their own assessment in the outcome of their application.

5.2.3 Only adjusting the price path to reflect prudent expenditure

We support the change that requires the Commission to adjust the price path for only prudent expenditure for the reasons provided.

However, we do see some challenges in applying this in practice and would like to understand how the Commission will test whether the expenditure is prudent and how they will calculate any adjustment to the costs submitted. We suggest the Commission consider a framework that applies different levels of scrutiny depending on the circumstances. For example:

1. Rely on the application cost forecasts if:
    a. If the supplier will be, or has, procured by tender
    b. If a price that funds all of the expenditure has been negotiated with a connecting party who will be paying that price (for foreseen and unforeseen capex)
    c. Expenses have been externally tested or verified as part of the application
2. Expenses externally tested and the application adjusted if the application hasn't provided sufficient verification of prudent expenses.

5.2.4 Consideration of whether an application is better suited to a CPP

We have concerns that the ability to turn down a reopener because a CPP is better suited, will make reopener decisions more subjective, and the outcomes less certain (counter to Section 52R of the Act). It's important that a supplier and the customer (for new connections and network growth) making a reopener application that has met the criteria, has the confidence of the decision outcome so they can plan and reprioritise their work programmes as needed.

This IM change should be supported with framework of when a CPP will be more appropriate. The framework could include materiality guidelines, the types of costs a DPP application would not support and any other CPP triggers. It will be important to avoid the situation of a supplier making a DPP reopener application has it declined and then having to make a CPP application, adding unnecessary cost and time.

5.2.5 Timeframes within the reopener process IMs

We disagree with not having timeframes. New Zealand decarbonisation will be directly reliant on the speed at which EDBs can provide more capacity to support electrification. EDBs are expected to provide delivery timeframes that customers can then incorporate into their own delivery timetables. An application process reflects a significant proportion of a delivery timetable and will also have to be included in a work programme to allow customers to allocate their project resources to when they are needed.

We understand that there is some uncertainty in the reopener application process and the decision is dependent on the information needed being available. However, this is the case with all projects and there are project management practices designed to manage uncertainty. For example:

- Participation in project updates, providing timetable updates to any changes.
- Providing assumptions to the project timelines stating where timelines could vary under different circumstances (like correct information not being provided).
- Breaking timelines down into the components of the process that only the Commission are responsible for, excluding timelines for suppliers to provide input.

A customer's delivery timeframe needs to include all aspects of the delivery of a project and we believe it's reasonable to expect the Commission to provide and work to time limits. It's also reasonable to expect that it will take time for a new process to be embedded into practice and for the Commission to streamline the process. Commission processing times could be published (using a scorecard) demonstrating performance against the timeliness and highlighting reasons for delays. The scorecard would be used as a guide of where the Commissions process improvements should focus.

Alternatively (and ideally), it could be explicit that suppliers could implement works in parallel or retrospective to an application being made, making it less important for networks to have set time frames. This assumes that the application of reopener criteria becomes standardised and there is no uncertainty about whether they would be approved. We believe that the process would need to be bedded in and well understood and tested before this could be done with confidence. We believe the regulatory framework should evolve to the point where it supports a customer to connect whenever they need and there are no restrictions imposed on their works programmes and connection timetables.

5.2.6 More prescription to guide reopener applications

We agree with the general approach of not providing more prescriptive IMs for the reasons given.

However, we do think there is an opportunity for suppliers and the Commission to develop guidelines to guide the application content. This could be based on successful applications and feedback on how unsuccessful applications could be improved.

5.2.7 Need for reopener application windows

We support the decision not to include an application window. It is important to remember that most EDB reopener applications will probably be in response to customer connection requests. The regulatory rules should enable customers to connect to distribution networks or access more capacity when they need it. This will be especially important as New Zealand decarbonises and customers transition from fossil fuels to renewable electricity. The customer's connection requirements should drive EDBs work programmes, not regulatory timeframes.

5.2.8 Inclusion of a pre-application stage

We support the draft decision to not have a pre-application stage. We think a more efficient way of achieving similar benefits could be achieved from:

- early engagement with the Commission on more technical or complex applications
- the additional clarify provided in the explicit IM information requirements
- The industry developing guidelines and templates that could be provided to the Commission for feedback.

5.2.9 Allowing reopeners to be moved across regulatory periods

We do not believe that the Draft IM Decision correctly identifies the key issue created by limiting a reopener to a single DPP regulatory period. We agree with the Commission's description of how the regulatory mechanisms work if a project is delayed and falls into the next regulatory period (the IRIS will reward an underspend in one regulatory period and then will penalise an overspend in the next regulatory where the project has been delayed into) and with how a supplier can include project spend spanning regulatory periods in their AMP and the DPP for the next regulatory period). We support the overall approach of providing an allowance and then rewarding or penalising networks on how efficiently they can deliver those budgets.

The issue we were highlighting in our submission to the issues paper is that the regulatory framework is driving the timing and project plans of some reopener customer projects, rather than a project plan reflecting a customer's own requirements. Large projects that meet the materiality limits of the reopeners tend to have long delivery timeframes that can be 2-3 years, especially if they required high voltage reinforcement. The Commission will not approve a reopener for any additional funding for a customer project unless that project can be designed and built, and the final assets commissioned within the same regulatory period. The regulatory rules also mean there is no point in the Commission approving a reopener that's not commissioned within the regulatory period as capex allowances are applied on asset commissioning, not capex expenditure, and an asset commissioned outside of a regulatory period would have no impact on a price path or allowances. Accounting rules also means that a supplier cannot part commission an asset before it's operational so that a proportion of the project expenditure can be included within a regulatory period.

However, some large projects that won't be commissioned until next regulatory period, will still need capital expenditure in this regulatory period to meet customer time frames. This means that suppliers will have to delay these types of customer projects until the next regulatory (potentially for 2-3 years) when funding becomes available either through the next DPP or by making a reopener application. As stated in our submission to the Issues Paper, "practically, this limits the use of reopens [sic] to smaller projects that can be started early in the regulatory periods so that they can be completed before the regulatory period ends."

We have three large public electrification projects that are likely to be delayed until the next regulatory period because they cannot be delivered within the remaining two-year window of this regulatory period. We have permission to describe one in detail. Kiwirail has ordered two hybrid electric/diesel Interisland Ferries, the first of which is expected to arrive in New Zealand late-2025. A new connection is needed in Wellington to charge the ferry between journeys. Building the new supply point is complex and the design and works will take two years, with the commissioning date falling just after the start of the next regulatory period. Reopening the DPP3 price path now provides no benefit because, while the majority of the capex expenditure will be this regulatory period, the commissioning falls in the next regulatory period. Allowances are based on Commissions Assets and not capital spend, so reopening the DPP3 would provide no additional funding for the project. Capex is scarce due to other emission-reduction-related expenditure, and we don't have the headroom to re-prioritise the capex allowances. The risk now is that by delaying the project the new ferries will arrive and not be able to operate as expected. This will impose costs and disruption to Cook Strait customer services.

Our choices include delaying the work programmes or having the customer pay for the project. Increasing customer capital contributions is an option for some projects. However, where a project has a large network reinforcement element that will benefit wider network customers (most emissions reduction-related demand increases in Wellington are expected from existing connections) then the connecting customer will be subsidising many other network users (like households transiting to electric vehicles and away from using gas).

We could also start building without the allowances approved and assume those allowances will be awarded in the next DPP or by a subsequent reopener. However, in some cases the project will have been completed and commissioned before the allowances will have been approved, especially if the DPP gates cut the overall capex back and more time is then needed to apply for a reopener in the next DPP. It is also becoming less certain about whether a reopener would be awarded. The risk of an IRIS penalty applying increases as the reopener decision to approve the allowances becomes even more subjective under the Draft Decision:

- Adjusting the expenses if they are not deemed to be prudent – which would be applied retrospectively if the project was started before the allowances were approved;
- Declining the application due to consideration of the impact of the reopener event given the relevant circumstances, including both positive and negative effects, on the EDB's costs, revenues, and quality outcomes;
- Declining the application due to consideration of the EDB's planned capex and opex for the remainder of the regulatory period have been appropriately reviewed and reprioritised; and
- The Commission may determine that a CPP proposal is more appropriate. By the time a CPP application would be made, the project is likely to have been commissioned and an IRIS penalty incurred.

Proposed solutions

We have considered two solutions, both would allow an EDB to start building large projects at the end of one regulatory period while commissioning the project in the next. The options are:

1.) Apply the additional capex allowance provided by a reopener application as capex expenditure, rather than commission assets. This would provide EDBs access to allowances as soon as they need to start building, and not have to wait to the regulatory period when the asset is commissioned to have access to the allowances. There is precedent for this – all past DPPs have used the latest available AMP capex forecast which is based on capex expenditure to set allowances. The DPP assumes that commissioned assets equals capital expenditure.

2.) Apply a new mechanism that allows a reopener to be approved in one regulatory periods and automatically applies those allowances in the next if that's where the assets will be commissioned.

We think that reopeners that allow EDBs to deliver new connections and demand increases that better meet customer timeframes and requires promotes the long-term benefit of consumers (promoting the purpose of Part 4) and provide customers with regulatory certainty, (promoting the purpose of the IMs).

We disagree with the Draft Decision that a mechanism that allows rollover of reopeners between regulatory periods does not incentivise investment or efficiency improvements more than the status quo and therefore does not promote the s 52A purpose of the Act. The approved allowances would be included in the IRIS capex targets for the next regulatory period which would ensure the same incentives to save costs are still applied.

We also disagree with the Draft Decision that a mechanism that allows the rollover of reopeners between regulatory periods could create situations where multiple reopeners are sought where it may be more appropriate to utilise a CPP. Applying for a single reopener that can apply across multiple regulatory periods avoids applying for multiple reopeners. It is also important to note the Draft Decisions reopener CPP test would also apply to capture applications that are better suited to a CPP.

Our recommendation is to either apply allowances based on expenditure (not commissioned assets) or allow a reopener to apply across regulatory periods to enable customer projects to be implemented when they are needed, and not when the artificial barriers of the start and end of a regulatory period allow them. It is important to re-iterate, our issue with the current reopener framework is not to capture project delays – we agree the IRIS already captured this well – it's to support customers to connect when they need to and so we don't slow their own decarbonisation plan. We have multiple, real examples of the current regulatory framework driving the delayed timing of customer work programmes[21].

5.2.10 'Reopener event allowance' recoverable cost

We support the Draft Decision's 'Reopener event allowance' recoverable cost. We agree that this provides a simpler and more consistent method for recovering prudent and efficient costs.

5.3 Whether the reopeners will cover future circumstances

5.3.1 Inclusion of opex

We support the inclusion of opex for system growth unforeseeable major capex projects and the Foreseeable major capex project reopeners. It is important to promote flexibility solutions in the regulatory model when they will provide a more efficient solution.

We also support changes to allow the ability to recover consequential opex (and the equivalent for capex in respect of an opex solution). It is important that EDB's can capture all of the costs of a new investment in the cost recovery mechanisms so they can maintain a real return.

We agree that these changes will promote the purpose of Part 4 more effectively.

5.3.2 Electricity distribution system growth

We support the Draft Decision to amend the IMs to make it clear that reopeners are available for network growth capex driven from general growth. As highlighted in our submission to the IM Issues Consultation[22], general growth will drive a significant proportion of future demand and that the location and speed of that growth his uncertain.

We do not agree that networks will be able to plan for *all* general growth scenarios and that EDBs will be able to capture any related network capex growth within the 10-year AMP planning window. The unforeseen Reopener should also be available for general growth scenarios that require unforeseen network growth capex.

Specially, the transition away from gas is still uncertain (the gas strategy will be released at the same time the final IM decision is released) and different transition scenarios could result in unforeseen network growth capex that is not capture in an AMP. Our current AMP plan assumes the gas transition

[21] These projects are confidential but we have been discussing them with the Commission.
[22] Page 40, [Wellington-Electricity-Submission-on-IM-Review-Process-and-Issues-paper-and-draft-Framework-paper-11-July-2022.pdf (comcom.govt.nz)]

will be late in the 25-year ERP plan to provide time for the industry to build the new renewable generation needed to replace it. Much of our network growth capex in response to the gas transition is currently outside of the 10-year AMP planning window. If the Government's gas transition strategy accelerates the removal of gas, then there would be network growth that wouldn't be reflected in the AMP and would not be available for the reopeners.

We would need early confirmation of this IM change is retained so that we can include the additional network growth capex needed to support an accelerated gas transition (in case that's what the gas strategy recommends).

Classification of foreseen capex

We note the Draft IM Decision requires a project or programme to be clearly identifiable in the AMP for a project or programme to be classified as foreseen. An EDB will probably forecast LV system growth as a general budget rather than identifying specific networks that may run out of capacity. Currently networks do not have visibility of constraints and capacity headroom on their LV networks. Networks will have to develop models to estimate how many networks they think they will need to reinforce each year. We are currently developing forecast models for our 4,500 LV networks based on the probability a network will exceed its capacity constraints. We are using these probabilistic models to build up an annual capex budget. While it's unlikely that a network will be reinforced in the specific year identified, on average the number of networks we are reinforcing should align with the total budget.

It will be important that the reopener framework allows LV network growth to be treated as a single programme. While a variation in the timing and cost of a single LV reinforcement project (e.g. adding a new transformer or larger cables) will not be a material impact on allowances of the IRIS, bringing forward the reinforcement of multiple LV networks would be. This situation is conceivable or even probable if an external driver incentivises faster-than-expected EV growth or electrification of gas use. Examples of external drivers that could drive faster than expected demand increases could be further government EV incentives, an EV battery technology step change, price break on new EV models or banning new gas connections.

5.3.3 Additions to the reopener provisions - resilience expenditure

We strongly support the expansion of the foreseen and unforeseen re-openers to include pre-emptive resilience programmes. Networks will need to ensure they can maintain a secure electricity supply and customers move more of their energy needs to the electricity system and become more reliant on electricity. The reopener will provide suppliers an important tool to be more flexibility in their preparations towards vulnerable assets, natural disasters, cyber threats and climate change adaptation.

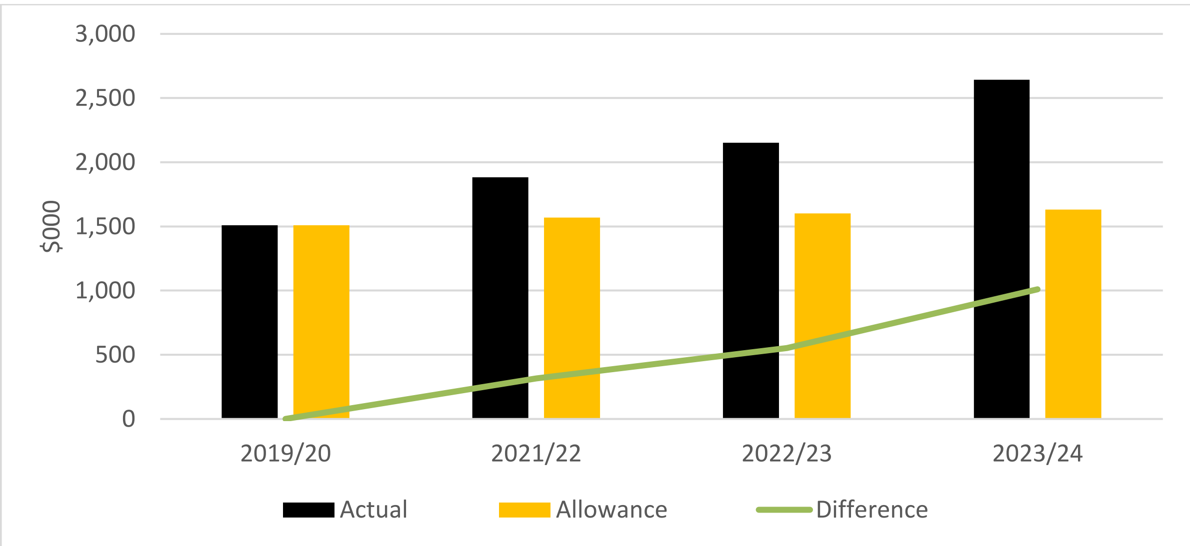
5.3.4 Additions to the reopener provisions – risk events

We strongly support the inclusion of the risk event reopener for EDBs. We have several examples of unexpected asset failures that have needed significant investment to maintain quality targets. We have been able to successfully reprioritise other work programmes in response. However, we are experiencing increasing pressure on allowances due to unexpected decarbonisation-related projects and we may not be able to reprioritise capex in the future without it impacting our ability to connect customers or meet capacity increases (we prioritise maintaining a secure supply over new connections).

5.3.5 Additions to the reopener provisions –general reopener/general escalating costs

We disagree with the decision to not include a reopener for unexpected cost escalations. As highlighted in the narrative, there is no ability to adjust allowances for unexpected and significant increases in operating costs. For example, we have experienced above-inflation insurance cost increases which now means we have to find $1m in savings each year (equivalent to 3-4% of our total opex allowance) to cover the gap in allowances. The consequence of doing this is we are reducing the amount we could be investing in the innovation like that needed to develop LV management tools, flexibility or in improving our network quality. Figure 8 summarises the gap between our allowances and actual insurance costs.

Figure 8 – Actual insurance costs compare to the insurance regulatory allowance



Also note, the insured value was reduced in 2020 to limit the size of the premium increases.

The In-Period Adjustment Paper reasons for not including a new reopener is because it’s difficult to provide criteria that would provide networks with certainty that a reopener would be successful. We disagree. Similar criteria to those applied to the capex reopeners could be used:

- Limit the reopener to opex increases (capex unexpected capex requirements are already well covered by other reopeners);
- A value limit to capture only material cost increases. $500k per year would be a similar equivalent to the 2.5m capex lower limit;
- Cost not covered in allowances – opex allowances are based on historic expenditure so networks can provide transactional financial data to prove this;
- Evidence that the cost increase couldn’t be avoided without impacting service quality (e.g. for our insurance increases, we could stop paying insurance which would push the risk back on the customer to fund all damages post-event in a natural disaster).

We don’t think this is necessary to clarify the types of operating costs that a reopener could apply to. We think a better approach to use criteria to identify whether the costs increases are necessary for maintaining existing service levels.

We also disagree with the In-Period Adjustment Paper that suppliers could be disincentivised to reprioritise and manage their costs within the allowances. Material increases will mean that reprioritise means stopping essential functions. The combination of basing opex allowances on historic expenditure and the IRIS cost-saving mechanism (we are incentivized to continuously rachet costs down) means that at Wellington Electricity, we do not have discretionary opex allowances available to cover large, unexpected cost increases without forgoing essential functions.

5.3.6 Additions to the reopener provisions – contingent project reopener

We think there is an important role to play for contingent project reopener and should be introduced for both the DPP and CPP IMs. We think contingent project reopener provide a better alternative to foreseeable and unforeseeable capex reopeners when an investment:

- is highly probable but the timing is uncertainty;
- the timing can be identified by a trigger.

A contingent reopener would allow an EDB to preapprove a project so that it can be delivered in a more timely way than a foreseeable and unforeseeable capex reopener. The delivery timelines could be reduced by the length of the application timeframe. This would also remove significant project timeline uncertainty.

We disagree with Draft IM Decision that this would not be light-handed regulation. The reopener already has a level of scrutiny that would be similar in application to a contingent reopener. The difference being the contingent reopener application would be done upfront.

5.3.7 Categories of expenditure

While we agree that a reopener isn't the best mechanism for the types of non-network costs described in this section, many of the costs described aren't captured in the current DPP price path and networks need this new capacity to support electrification and the step change in electricity demand. We agree with the Commission that networks will be able to reprioritise expenditure to cater for timing uncertainty. However, this assumes there are allowances for these new functions to allow expenditure reprioritisation and networks don't have to cut important functions instead.

Much of the new capability needed, like the development of a DSO function, management tools required for LV network visibility or the incorporation of flexibility into demand responses, is immature and EDBs won't be able to provide firm cost estimates. Careful thinking will be needed to make sure the DPP opex setting process, non-network capex gates and innovation allowances are not too restrictive (i.e. don't award allowances because the budgets are uncertain) and essential allowances are provided to develop and operate new functions like DSO and flexibility.

5.4 Reviewing our approach to reopener thresholds

5.4.1 Lower materiality thresholds

We generally support the Draft Decisions reopener thresholds. We think including a consistent dollar threshold in addition to the FNAR impact provides a pragmatic improvement that helps simplify the application of the reopeners. We also agree with the mechanics of how other, non-capex costs are included into the assessment of whether the minimum levels have been met. We think they are simple and quick to calculate and aggregate with the capex forecast expenditure.

5.4.2 Upper materiality thresholds

We support removing the maximum thresholds so as not to exclude high-value projects that could exceed the maximum threshold but are not complex enough to warrant a full CPP. We also note that an upper limit would no longer be needed because of the new reopener assessment criteria of whether a CPP would be a more appropriate solution to a reopener.

5.5 Introduction of a large connection contract mechanism for EDBs

We support the Draft Decision large connection contract mechanism. We agree that this will streamline the connection process and will help networks address expenditure uncertainty. In practice, we are structuring the commercial terms for our very large connections in a similar way as to what is being proposed. We have a separate direct agreement which includes negotiated operational and payment terms and we calculate unique tariffs which cover all connection costs and contribute towards shared cost. The advantage with the Draft Decision is we would then not have to apply for additional allowances through a reopener to fund the connection. This would speed up the connection process.

We suggest that the connection size used to define what a large connection is could be removed to provide more connections access to the alternate connection process. Only customers that can negotiate from an equal commercial footing would agree to commercial terms outside of the regulatory framework. A customer can always not choose to use the large connection contract mechanism. We believe the Commission can rely on this mechanism only being used when the two parties agree, as an alternative to the 10 MW connection limit.

We would note another important advantage of this mechanism is that it’s not dependent on delivering the programme within regulatory time periods – it is regulatory period agnostic. The connections can be programmed to fit with the customers’ requirements and any associated transmission work programmes and don’t have to consider whether it can be delivered before the end of the regulatory period.

For this reason, we also ask that the Commission make this mechanism available for the remainder of the DPP3 regulatory period. This may allow some customer connections that can’t be delivered before April 2025 to be started before DPP4 allowances are approved in December 2024.

5.6 Whether other potential in-period adjustment mechanisms are necessary

5.6.1 Increasing the scope of pass-through costs or recoverable costs to cover a wider spectrum of categories of costs

We disagree with the general exclusion of adding any costs to what can be passed through. We agree with the general tests being applied and we think that where specific costs types meet the test provided in 9.35 of the In-Period Adjustment Paper, then it’s in the customer’s long-term benefit to pass them through i.e. where an EDB cannot avoid or control cost fluctuations, they may have to then reprioritise cost over other essential functions needed to provide services at a level customers want.

Specifically, we think insurance costs should be a pass-through. Insurance cost fluctuations are generally outside of the control of the supplier as they are dictated by the wider insurance market. Yes, effective procurement will ensure the lowest cost is selected from offers at the time, however, the underlying price change is the same across all providers. The cost savings from efficient procurement are immaterial compared to cost changes from the overall market movement.

Insurance is also ultimately to the benefit of the customers – reducing the amount of any future price increases needed to repair equipment damage after a natural disaster. Networks currently bearing any cost fluctuations, are made whole post-event for repairs and equipment replacement costs that insurance doesn't cover. Currently, networks are incentivised to reduce coverage and increase a customer's exposure to post-event recovery costs in response to an insurance cost increase. Customers are the beneficiary of a network maintaining prudent levels of insurance coverage and are therefore best placed to bear the risk of cost fluctuations.

We believe that insurance is best treated as a pass-through to ensure that customers maintain a prudent level of coverage. We also believe that insurance costs pass the tests of what could be treated as a pass-through cost (provided in Figure 9).

Figure 9 – testing insurance costs against the pass-through

Definition of a pass-through is provided in clause 3.1.2 (3)	Insurance costs
associated with the supply of electricity distribution services	Yes, insurance is to provide customers with the ability to cover the costs of repairing or replacing assets damaged in a natural disaster.
outside the control of the EDB;	The majority of insurance cost fluctuations are outside of the control of an EDB. While good procurement practices can provide some cost savings, the majority of movement is market driven.
not a recoverable cost	Not a recoverable cost
appropriate to be passed through to consumers	Customers are best placed to bear the risk of cost fluctuations as it is the customers who benefit from maintaining a prudent level of insurance coverage (a customer would have to pay more post-event if coverage is reduced). EDBs would be made whole post-event for any reduction in coverage and are currently incentivised to recue coverage in response to above inflationary increases in insurance costs.

Definition of a pass-through is provided in clause 3.1.2 (3)	Insurance costs
one in respect of which provision for its recovery is not otherwise made explicitly or implicitly in the DPP or, where applicable, CPP; and	Currently insurance is provided in opex allowances. However, the above inflationary increased experienced over the last five years are not included (see section 5.3.5). If insurance was included as a pass-through, then opex allowances would have to be reduced by the same amount to ensure the cost was not double counted.
come into effect during a DPP regulatory period or, where applicable, CPP regulatory period.	Insurance costs are paid each year.

Insurance costs reflect the characteristics of costs that are best suited to be passed through – while they are foreseeable, suppliers are exposed to significant cost fluctuations that are outside of their control. Given a supplier's inability to control cost fluctuations and that customers are the beneficiary of prudent insurance coverage, we think customers are bets placed to manage risk.

If insurance costs were treated as a pass-through, we do note that it would be important for networks to externally review their current insurance coverage to ensure it reflects a prudent level of courage for their customers before insurance costs are transitioned to a pass-through. For example, this would mean checking that our current approach of only insuring for our substation and zone substation assets is a prudent approach. We also believe that this should then become an obligation for networks to regularly check their coverage remains prudent.

We note that the Australian Energy Regulator which regulates electricity distribution services has reached a similar conclusion and is passing through insurance costs. This is in response to bush fire insurance costs which are fluctuating in a similar way to insurance costs in New Zealand i.e. large bush fire events have resulted in significant premium increases. Contingent expenditure allowances

We agree with the decision to not include a contingent expenditure allowance and treat the allowance as a recoverable cost. The types of costs best suited for contingent expenditure would be growth capex (network reinforcement) - costs that are (generally) foreseeable at the time of setting a price-quality path but the timing is certainty and where the timing can be identified by a trigger.

However, contingent expenditure allowance would fall outside of the IRIS and there would be no incentives to find cost savings and provide more efficient solutions. Specifically, EDBs wouldn't be incentivised to consider flexibility and non-wire alternatives.

5.6.2 Use-it-or-lose-it allowances

We agree with the decision to not include a 'use it or lose it' allowance as there are better ways of providing allowances for innovation and non-traditional solutions.

This view is caveated with EDBs currently don't have access to innovation allowances needed to develop the capability and processes to incorporate distributed energy resources and flexibility into their asset management practices. While we don't think this is the right mechanism to provide these allowances, there is still a need for better access to innovation funding.

5.6.3 Quantity wash-up mechanisms

We disagree with the new connection wash-up mechanisms as most future demand growth will come from existing connections (and not from new connections) and the proposed new mechanism will not capture growth uncertainty and provide the expected benefits. We also think that the new growth that does come from new connections will come from large process heat conversions which will make calculating a standard cost reflective of the actual capex spend difficult. We discuss this in more detail in section 3.1.3.

6 Non-topic paper changes

6.1 Minor corrections to the existing IMs

ENA and its members have reviewed the existing IMs to identify practical implementation and drafting issues and proposed correction. The ENAs submissions provides a log of its findings and recommendations.

6.2 Definition of operation costs

WELL does not support the proposed amendment to the definition of operating cost to exclude the costs of appeals under sections 52z, 91 of the Act. Removing costs of appealing from operating costs diminishes an EDBs ability to challenge the Commission on an IM decision that may not be aligned with the purpose the Act. It should not be the sole expense of a supplier to bear the costs to challenge inequitable decisions. Customers also benefit from suppliers who are adequality incentivised to innovate and to invest in distribution services and should share in the cost of networks ensuring the regulatory framework enables them to continue to do this.

6.3 Revenue cap refinement

Along with the other five large EDBs, WELL has engaged Frontier Economics as topic experts, to respond on our behalf to the Draft IM for the revenue cap and washup account. The report has been submitted separately to this submission and is titled "*A review of the limit on EDB price increases and support analysis for the six large distribution networks.*". This submission will refer to this report as the '*Frontier Report'*.

Further changes are needed to the revenue cap washup adjustment (the application of a cap on revenue increases) in addition to the Draft IM decision changes that include reclassifying Transpower costs as 'pass though' costs and excluding them from the washup calculation. Even after the Draft IM changes (and assuming the current DPP assumptions will also roll over) there is a risk of the washup accounting building to the point that the revenue become unrecoverable and/or cashflow shortfalls create financeability issues.

The expectation of the Commission when setting DPP3 was that the 10% cap of revenue increases would rarely bind and when it did, EDBs would be made whole for any delay in receiving their revenue through the application of a time value of money adjustment. Changing economic and operating conditions could mean that the price limits will bind more often and could bind for consecutive regulatory periods. The price limit is likely to bind more often for future price paths because:

- Networks will have to invest more to deliver New Zealand ERP;
- Past inflation rates have increased the RAB;
- Future inflation is likely to remain high;
- Government bond rates are high and look to remain high increasing WACC

The Frontier Report analyses the impact of the Draft IM Decisions price cap, other DPP3 settings and washup account under future investment and cashflow scenarios. The study assesses the impact of applying the price cap against the relevant regulatory principles from Part 4:

i. The regulatory framework should provide EDBs with a reasonable expectation of recovering all of their efficient costs over the lifetime of the assets;

ii. The regulated cash flows in each regulatory periods should be sufficient to support the benchmark credit rating (at the benchmark level of leverage) assumed by the Commission when setting those allowances in the first instance; and

iii. The regulatory framework should provide EDBs with effective incentives to make efficiency improvements that can be shared with consumers, and provide consumers with regulated services at a level of quality that reflects consumer demand.

The Paper has been submitted separately on behalf of the other five large networks, in response to the Draft IM for the revenue cap and revenue washup mechanism.

The study found that the price cap could bind EDBs to the extent that they will not be able to recover all of the revenue in the washup account. If EDBs cannot expect to recover all of their efficient costs over the lifetime of the regulated assets, then investors in the EDBs are unlikely to supply the capital required to invest in regulated assets. This would not promote the Part 4 purpose and meet the principles outlines above. Figure 10 provides the cumulative washup balance of the big six networks. The indicative modelling suggests that nearly $1.5 billion of revenues could be left unrecovered by the end of the DPP4.

Figure 10 - Cumulative wash-up balance ($000s nominal)

Year	Closing wash-up balance
2026	$359,135
2027	$684,911
2028	$984,489
2029	$1,247,404
2030	$1,452,714
2031	$404,553
2032	$731,427
2033	$946,020
2034	$1,002,448
2035	$860,405

Source: Frontier Economics analysis of EDB data

We support the studies recommendation that removing the price limit altogether would result in more efficient outcomes, and therefore better promote the Part 4 purpose, provided that EDBs seek to recover all of their efficient costs in each regulatory period. This would allow EDB’s to set prices that reflect the underlying economic costs of supplying network services. This would improve an EDB’s ability to set prices that recover the efficient cost of existing infrastructure assets, encouraging efficient investment in the network, and signal to users the cost of new network capacity, so as to encourage efficient usage of infrastructure capacity. Removing the price limit will also means customers in future regulatory periods will not subsidising the cost of supplying customers in the earlier regulatory periods.

If the Commission decides to maintain the price cap, then we also support the alternate recommendations in the Paper, including:

- Restrict the price limit to a shorter, defined period of time (e.g., one or two years) so that the period over which cost recovery is deferred may be reduced.
- Increase the cap to 15% to still smooth price shocks while reducing the probability it will bind to the extent that it constrains routine price changes.

We also support the recommendations to include an IM that specifies how it would reset starting prices. Suppliers and customers should have certainty about all of the fundamental building blocks of a price path. Currently there is uncertainty about what future starting prices will be.