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Dear Mr Gunnell

Part 4 Input Methodologies Review 2023 – Process and Issues paper

1. Introduction

Wellington Electricity Lines Limited (**WELL**) welcomes the opportunity to make a submission in response to the Commerce Commission's (**Commission**) "*Part 4 Input Methodologies Review 2023 – Process and Issues paper*" and "*Part 4 Input Methodologies Review 2023 – Process and Issues paper*" published on 20 May 2023. This submission refers to the papers as the "**Draft Framework**" and "**Process and Issues 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.

This submission provides feedback on both the Draft Framework and Process and Issues Paper. The Draft Framework is based on a well-developed and refined decision framework which WELL believes aligns well with the objectives (52A) of Part 4 of the Commerce Act 1986 (**Part 4**). Our submission will focus on ensuring the Climate Change programme, which will drive the majority of new investment going forward, is appropriately represented. We also suggest expanding the principles used to guide how the purpose of Part 4 52A is promoted, to including a financeability test.

The Process and Issues Paper captures most of the issues that should be addressed in the Input Methodologies (**IM**) review. Given the breadth of the IMs, the complexity of some of the upcoming regulatory challenges, and limited resources in the industry and at the Commission, we are aware that the review will need to focus on the key issues. This submission therefore focuses on the key issues which we believe are a priority. We have provided case studies from our own network planning and capability development programmes to illustrate and support our prioritisation of the issues. Please note, our planning models (including demand forecasting and investment) are being continuously developed and refined and often use high level assumptions. The modelling results used in the case studies are provided for illustrative purposes only. The case studies highlight that the characteristics of the future investment programme have changed from the business-as-usual investment the DPP was designed for, or the well understood, step changes in investment for lifecycle asset replacement programmes the CPP suits. The submission then uses the case studies to show the specific components of the regulatory framework that need addressing so that EDBs have appropriate allowances and incentives to deliver future investment consistently with the objectives of Part 4, 52A.

Our forward planning assumes that flexibility services will be developed as a viable non-wire solution for managing network congestion. The development of flexibility services is dependent on a number of steps and actions being successfully completed – many of those steps and actions being outside of the scope of an EDBs responsibility and the IM mechanisms[1]. For example, a prerequisite of a flexibility service is for customers to invest in smart devices that are capable of being managed by a flexibility provider – without this, flexibility serviced will not be possible. In addition to enabling EDBs to invest in the capability to use flexibility services, we ask that the Commission support and lobby for the other changes outside of the Part 4 regulatory framework that are also needed to enable flexibility services. The benefits provided by flexibility services will not be realised if Part 4 changes are made in isolation to the overall electricity regulatory environment.

Part 4, the IMs and the Price Path Determinations all interact together to provide an EDB with the allowances, incentives and quality targets to fund and operate their network. Our submission focuses on the key regulatory issues and changes that we believe need to be made overall and does not only focus on the IM regulatory features. A solution to an issue may require changes to both the IMs and a Price Path Determination. Where solutions require changes to both components, we believe that changes to a Price Path Determination should be at least noted as an outcome of the IM review, and a commitment made to also make those changes in the future. Without this commitment, stakeholders cannot be confident that an issue will be resolved as expected.

The Electricity Network Association (**ENA**) has also provided a submission in response to the Process and Issues paper. WELL participated in the submissions development and supports the views of the ENA's submission and its assessment of the issues and the prioritisation of those issues. This submission builds on the ENAs views and provides further context around the prioritisation and possible solutions.

2. Draft Framework

WELL supports using the proposed review framework. The framework is well understood, it has been tested in practice and provides consistency between reviews

2.1. Mandatory consideration of 5ZN of the Climate Change Response Act 2002

We strongly support making consideration of the 5ZN of the Climate Change Response Act 2002 (**CCRA**) mandatory and not an optional consideration. The impact of the ERP of future investment

[1] Our EV Connect project identified all of the steps needed to developed flexibility services and identified which entity in the supply chain is responsible for its implementation. The EV Connect Roadmap is discussed in section 3.2.1.2.

programmes is significant and EDBs need confidence that the regulatory framework and the regulator will support EDBs to make those investments.

As highlighted by the Climate Change Commission in its 2021 '*Draft Advice for Consultation'* and by the Government in its ERP, reducing carbon emissions is in the best interests of New Zealand long term welfare. The New Zealand Government will expect businesses to participate in delivering the ERP and for regulators to support investment in those businesses and industries. Distribution business will play a central role in delivering the ERP and will be expected to make significant investments in their networks to deliver the expected increase in climate change related electricity demand. The draft framework sets out that the Commission *may* have regard to 5ZN of the CCRA.

We do not believe that delivering New Zealand's ERP should be left optional and we believe that the review framework should make consideration of CCRA as a key decision criteria. We also believe that delivery of the ERP aligns with the objectives of Part 4 52A as it is in the 'long term benefit of consumers' – making consideration of CCRA mandatory would not conflict with the objectives of Part 4 52A.

Adding a financeability test

We would also like to recommend adding a financeability arm to the principles[2] used to guide how the purpose of Part 4 52A is promoted. While financeability is not strictly an economic principle, maintaining stable returns and solvency are an important consideration of providing an incentive to invest. Investors in regulated infrastructure businesses invest for modest, low risk and stable returns (which is why many global investors in these types of investment are pension funds). A reasonable investor investing in infrastructure assets will be incentivised by an expectation of a real return, but disincentivised if the profits delivering that return are volatile.

While a regulatory mechanism may maintain ex-ante real financial capital maintenance from an economic viewpoint, the timing of the resulting revenue and cashflows may not allow a network to maintain its financial solvency. In a 'business-as-usual' operating environment, an EDB will have debt headroom to fund any differences between regulatory allowances and outgoing cashflows and the regulatory mechanisms compensate the EDB for any funding costs. However, as EDBs are expected to invest more to deliver the ERP related demand, funding will become increasingly scarce and an EDB may not have the headroom to fund any timing differences between regulatory revenue and cash requirements. This could then impact an EDBs financial health or its ability to invest as required (and in turn risk not delivering the ERP objectives or service quality).

We ask that a financeability test, like that used by Ofgem/Ofwat/IPART, is used alongside the three other principles to guide the development of solutions to the IM issues identified.

Ofgem and Ofwat test in the UK is based on the criteria that lending institution use to assess credit risk and set credit ratings – i.e. under any changes to the regulatory mechanism, would a lending institution still award a B++ credit rating (or whatever the credit rating assumed in WACC is).

[2] Section X22 of the Draft Framework

The financeability test would provide important guidance to any adjustments to regulatory mechanisms that create differences between when an EDB receives revenue to fund an expense and when the expense is paid:

- Changes resulting if there are large differences between depreciation and capital expenditure
- Any refinements to the price smoothing element of the revenue cap
- Any change to the IRIS mechanisms where there are differences between timing of capex/opex substitution

A financeability test like that used by Ofgem and Ofwat in the UK. A test based on the criteria that lending institution use to assess credit risk and set credit ratings – i.e. under any changes to the regulatory mechanism, would a lending institution still award a B++ credit rating (or whatever the credit rating assumed in WACC is).

3. Processes and Issues

WELL commends the Commission on the process to date, which started with the 'Open letter—ensuring our energy and airports regulation is fit for purpose' Consultation in 2021. This has allowed for the early identification of most of the key issues. Of the issues identified, WELL believes there are three priority issues which are likely going to lead to significant regulatory changes:

1. Developing investment flexibility in the overall regulatory framework to allow networks to adjust and adapt their investment profiles to allow EDBs to deliver new capacity when it is needed
2. Providing innovation allowances for networks to develop the tools and processes to procure and use flexibility services
3. Providing EDBs with the ability to purchase flexibility services if they provide a more efficient method of providing new capacity than traditional wire solutions.

This submission presents case studies based on our own network planning to illustrate the changing characteristics of future investment programmes. The case studies are used to highlight the issues and challenges that would arise if the current regulatory model is not changed.

The case studies and issues summaries have been developed in the context of the Wellington network. The Wellington network is a compact urban network (172,000 connections) well suited for EVs and electrified public transport and has a large number (65,000) of gas connections. Other networks, rural networks or networks with large industrial loads, will have different demand profiles and different investment profiles – the issues for these networks are likely to be different again.

We believe a range of tools maybe needed to allow networks to select regulatory mechanisms best suited to the challenges they face. We believe this will require the Commission to step back to consider the regulatory framework as a whole, including how the DPP and CPP work together – how the determination and specific mechanisms work together to provide EDBs with a selection of tools to match their investment requirements.

3.1. Workshops

The solution to some of the issues are likely to be complex. We believe an additional process step is needed to work through these complexities. WELL suggests using industry working groups, with representatives from the Commission, to develop potential solutions[3]. Those possible solutions could then be included in the issues paper and Draft Decision consultations for feedback.

We commend the Commission for the two workshops it did hold for the DPP3 but believe they were too large to allow the co-ordinated development of solutions and a robust debate of the merits and weaknesses of each. The DPP3 workshops were useful to answer stakeholder questions and to clarify the draft decisions but were the wrong format to develop details solution to the very complex topics. Workshops with representatives from each stakeholder group and along with topic experts would provide an effective forum.

The workshops should be limited to addressing the complex topics that may introduce new regulatory mechanisms or make significant adjustments to existing mechanisms (rather than just refining existing mechanisms). Examples of these types of topics could be:

- Who will be responsible for ensuring the wider components of a flexibility services (e.g., ensuring chargers are smart), are developed so they are available as a non-wire solution? Who (and how) will fund flexibility providers to develop flexibility services?
- How do EDBs fund the development of the tools and processes needed to incorporate flexibility services into their demand response? How do EDBs support flexibility providers to develop the flexibility services EDBs need?
- How to provide EDBs with allowances to purchase flexibility services when its efficient to do so?
- What are the solutions to solve the debt compensation problem?
- How to provide efficient network reinforcement allowances when there is high demand uncertainty?

3.2. Risk allocation and incentives under-price-quality regulation

3.2.1. Outcomes and issues in the market for electricity lines services

Our submission has split the response to this topic in two to align with the Commissions two key concerns:

1. the role that efficiency and innovation performance have played in the significant expenditure increases we have observed
2. The future role that efficiency and innovation performance can play in the transition to increased electrification. Included in this response is our view on whether quality measures need to change going forward.

[3] Note request

3.2.1.1. Efficiency and innovation and significant expenditure increases to date

The Commission noted declining productivity and referenced the ENA's NERA[4] report provided as part of the DPP3 submissions, which also highlighted the declining trend. As highlighted in the NERA report and in other EDBs submissions provided as part of the DPP3 process, declining productivity is due to new costs that are not under an EDBs control, costs that could be avoided but at the expense of future network reliability and security, not meeting new statutory requirements (like the Health and Safety at Work Act 2015) or not mitigating new business risks (environmental, social and governance reporting).

While the expenditure does not improve the productivity metrics used in the Commission analysis, they still provide essential functions - while productivity may be declining, networks are not necessarily becoming less efficient.

The cost increases reflect the increasingly complex operating environments. Examples provided in the DPP3 submissions included:

- Investment in preparing for New Zealand ERP and the expected, but yet not realised, increase in demand
- The proportion of new demand delivered from existing connections (brownfields growth) is increasing. The works costs of brownfields network reinforcement is significantly higher (than greenfield) because of the complexity of working around existing infrastructure.
- Developing cyber security measures to mitigate the increasing cyber risk.
- Increasing traffic management costs in response to changes in the Health and Safety at Work Act.
- Investments in earthquake readiness and resilience, including seismic strengthen
- Developing sustainability functions and carbon reduction programmes in response to New Zealand ERP.
- Increasing insurance cost in response to the insurance market reassessing natural disaster risks

These types of cost increases (cost increases that do not result in a productivity index improvement) are expected to increase further as networks prepare for climate change related demand increase. The benefits from investments in decarbonation related activities, like developing flexibility services and improving low voltage visibility and management, won't be seen until networks have to provide more capacity to allow customers to connect their Distributed Energy Resources (**DER**) like EVs and solar. However, EDBs cannot wait until demand increases (i.e. productivity outputs improve) before investing or we risk not maintain supply security and network reliability.

Case study 1 provides examples of cost that will not impact productivity outputs and are adding to declining productivity. The case studies are provided in the Appendices.

It would be difficult, complex and expensive to provide a complete qualitative analysis of declining productivity. It would require a detailed study of each EDBs cost structure, developing an expanded set of productive drivers (to capture the value provided by new costs) and then breaking down those

[4] NERA "Opex Partial Factor Productivity for DPP3 Electricity Network Association" (18 July 23018)

costs into unit cost drivers. We also question the value of such a study given other complex regulatory issues that also need solving. While a decision is made about whether this work is needed, we hope the case study provides some evidence of the types of new costs EDBs must now fund - new costs which do not change the productivity outputs used by the Commission study, but still provide essential business inputs.

EDB profit levels provide further evidence that cost increases are outside of an EDBs control and are for business inputs that cannot be avoided. As noted by the Commission, EDB profits have been below the expected market return suggesting that EDBs are bearing the higher than inflation cost increases at the expense of returns to the shareholder. New operating costs or above inflationary cost increases are not captured by the DPP backwards looking allowance calculation. If an EDB is exposed to new costs not covered by allowances, it must either find savings elsewhere, avoid the cost or fund the cost from shareholder returns. The lower than WACC profits suggests that the costs cannot be avoided and savings to the extent needed aren't available.

We understand the upcoming price challenge with increases in WACC, inflation and depreciation coinciding with increasing investment programmes in response to ERP. Networks must apply strong cost controls to ensure that the step change in future investment is made efficiency. We ask the Commission to consider the upcoming price increase in the context of:

1. WACC inputs and inflation will change over time and customers have seen large recent price decreases due to these inputs being low. The treatment of economic inputs into the regulatory framework must be kept consistent to maintain ex-ante real financial capital maintenance (**FCM**) across multiple regulatory periods.
2. The reasons for the ERP and EDBs central role in decarbonising transportation and residential and commercial fossil fuel energy consumption. The climate change benefits should not be lost or forgotten as economic inputs cycle and the IM review focuses on cost efficiency.
3. The impact of the ERP on household energy costs – while distribution prices will increase in the long term as ERP related investment increases, the ERP related investment enables offsetting, non-electricity, energy cost savings. For example, electrifying transportation will avoid expensive petrol and diesel. Our EV 2018 study showed that transitioning to an EVs would increase electricity consumption. However, this cost increase is dwarfed by the reduction in overall household energy costs because of the removal of the cost of fossil fuels.

Figure 1: Impact on household energy costs of transitioning to an EV

3.2.1.2. Efficiency and innovation and the transition to increased electrification

Demand management by using flexibility services will play a central role in the future operation of Wellington's distribution network, providing customers with more efficient distribution services and providing EDBs with the time needed to build new capacity. Flexibility services use customer DER to shift electricity use away from congested periods on the network, delaying or avoiding network investment. The development of flexibility services will require a significant investment in research and development – changes are needed to the regulatory framework to support the level of innovation needed. This submission provides case studies to illustrate the important role flexibility services will play as electrification increases and to provide evidence of what activities will require innovation funding to develop these services.

Case study 2 summarises the value we expect demand side management through flexibility services to provide and the importance they will have in supporting us to develop a forecast 108% increase in peak demand that we expect the ERP and population growth to drive (a later case study will provide our future demand forecast). The case study illustrates how flexibility services will help us to:

1. Lower distribution price increases by delaying network reinforcement (our current forecasts show we can avoid $~310m in capital expenditure over the new 30 years);
2. Spread out our investment programme, providing us with the time to build new capacity and to reduce the impact of resource scarcity;
3. Provide some ability to mitigate demand uncertainty.

Our research and development programme has focused on testing the viability of using flexibility services through technology trials, with a focus on a managed EV charging service. We have been developing a roadmap of the actions and steps needed to develop flexibility services. EV Connect is our industry wide work programme that focuses on how more energy can be delivered through the existing network. This is part of an Energy Efficiency & Conservation Authority (EECA) LEVCF project. The EV Connect Roadmap can be found on our website at: https://www.welectricity.co.nz/about-us/major-projects/ev-connect/. The website also includes the consultation documents, stakeholder feedback and workshop presentations that were used to construct the Roadmap. We have also prepared a customer video explaining why it is important to manage network demand away from congested periods on the network: https://www.welectricity.co.nz/insights/show/climate-change-response/

We are also now participating in the FlexForum work group as the natural progression of our EV Connect programme –implementing the actions identified by the EV Connect programme. The FlexForum is a cross-industry group established in February 2022 to:

"Identify the practical, scalable and least-regret actions needed to integrate distributed energy resources (DER) into the electricity system and markets to maximise the benefits for Aotearoa New Zealand".

Practically, an immediate outcome of the programme will be trials that can be scaled into operational solutions. The intent is for the Flexforum members to develop trials together – the membership representing flexibility providers with access to controllable customers devises, retailers with the ability to develop scalable customer products and flexibility service users (EDBs, Transpower etc) who will develop their internal processes and systems to use the services.

Both EV Connect and the Flexforum have highlighted the need for EDBs to invest to develop flexibility services to the point that they can become a viable non-wire alternative. Case Study 3 summarises the specific actions that will require EDB funding. Some of the activities are well understood and can be funded from a network's capital programmes. Other Roadmap steps are less certain and require research and development.

EDBs will need flexibility innovation funding to:

1. Develop and test pilot flexibility services
2. Develop and test the tools and processes required to integrate flexibility services into demand management response
3. Develop and trial a market for trading flexibility services
4. Develop and trail common communication standards

The development of an effective flexibility service is central to being able to deliver the ERP and to reduce the price impact for customers. The size of the long-term benefits to customers means that customer should also share in the innovation risk and the risk and cost of funding innovation should not just sit with EDBs. The IMs and price path determinations should provide for innovation allowances.

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. Given the value of flexibility services to customers, both in terms of price and maintaining supply security (see case study 2), we think it is important that customers also share in the risk. Practically we think this means changes to the IMs and DPP to provide innovation allowances at a level large enough for meaningful research and development. As shown in case study 3 and in our EV Connect Roadmap, significant development is needed before flexibility services become a viable alternative to traditional wire solutions. EDBs in the United Kingdom and Australia have been provided material innovation allowances to develop these services and have been doing so for over five years (Ofgem allowances and ARENA funds) – New Zealand has significant develop to catch-up and realise the benefits these services can provide. It is also important to note that many of the steps needed to develop flexibility services are outside of the IMs and that wider regulatory changes are also needed - changes to ensure customer DER are smart and can participate in flexibility services, large customer devices are registered so networks can manage their connection and there is a common communication language. It is important that all industry participants and regulators work together to enable the benefits that the services provide.

We believe that any innovation allowances should come with the responsibility to share all research and develop results and incentives to collaborate and pool resources. Table 1 summarises future drivers of efficiency and innovation, how they influence the key issues and prioritisation of those issues. Some high-level solutions are also provided.

Table 1: Incentivising Innovation

Future efficiency and innovation drivers	Issue	Review priority	Possible solutions
Network investment is expected to significantly increase	Concerns about declining productivity - important to ensure inefficient investment isn't carried forward and exacerbated. The decline in productivity appears to be caused by increasing operational, regulatory and business complexity and reflects new costs that aren't resulting in increasing in the traditional output measures (See case study 1).	**Low**	While productivity is declining, operating efficiency has not – the new expenditure is required to operate in the current electricity environment. A detailed study to confirm whether networks are operating efficiency will be expensive and may not be conclusive due to the complexity of understanding network efficiency. We think there are more important focuses for the IM review.
Network investment is expected to significantly increase at the same time as global economic inputs will also push up prices (WACC inputs, inflation)	Increasing distribution prices and customer affordability	**Low**	As per the decision framework it is important to continue to consider who is best to bear forecast risk and fluctuations in cost inputs. However, it is also important to maintain a consistent approach to asymmetric risks are not created. In the transition from DPP2 to DPP3, customers benefited from low WACC and low inflation. Care must be taken if the balance of risk borne by customers and suppliers is now changed. It will be important to also consider the wider benefits that future investment programme will provide households – just focusing on increasing distribution prices would ignore the wider energy saving benefits (avoided petrol/diesel/gas/coal cost) that electricity's part in the ERP enables, and the primary benefits of reducing carbon emissions and the adverse impact of climate change. Electrification reduces carbon emissions, so carbon cost savings should also be accounted for in electrification benefits.
Networks will have to develop an important new non-wire capability	**Is demand management and the associated cost savings incentive (Part 4 54Q)?** The current innovation allowance mechanism does not incentivise the development of flexibility services because:	**High**	Provide innovation allowances that are large enough to fund the research and development needed to develop flexibility services. Amend the IRIS mechanism so that EDBs can share in the benefits of the cost savings the services provide:

Future efficiency and innovation drivers	Issue	Review priority	Possible solutions
to successfully deliver the ERP.	- The value of the innovation allowance is too small compared to the research and development programmes that are needed to develop flexibility services. EDBs therefore carry the majority of the risk of innovation as they have to fund it outside of any allowances provided. - The assessment of the whether the allowance will be award is retrospective (ex-post) so networks carry the full cost risk if the allowance is not awarded - Networks still have to fund half of the cost of research and development with no confidence they will receive any future compensation: - The IRIS does not reward capex cost savings received in future regulatory periods – EDBs may not have the ability to recognise any benefits - Most research will be for flexibility services which won't be available at the scale needed to make material capex savings for years (it has taken the UK 5 years to develop a meaningful flexibility response).		- Allow EDBs to benefit from capex savings from future regulatory periods - Consider a networks contribution towards innovation once the benefits sharing mechanisms have been set. i.e. if EDBs still carry the majority of the risk of innovation, then an EDBs contribution towards innovation should be correspondingly low.
	Who should bear the risk of innovation: Flexibility services will be an important tool for EDBs to deliver the ERP. The development of the new services and the tools and processes to incorporate the services into demand management responses, will be significant.	**High**	Customers should bear more of the risk of innovation give the cost and reliability benefits will flow to customers. Customers also benefit from the ERP benefits that flexibility services will help enable.

Future efficiency and innovation drivers	Issue	Review priority	Possible solutions
	Currently EDBs are expected to fund the majority of any research and development costs themselves for benefits that may not eventuate in future regulatory periods. While customers pay half of any allowance awarded, the small size of the available allowance means that networks are spending significant more. The majority of those benefits will flow through to customers who currently bear little risk.		
	The role of the IMs: Currently the IMs are silent on the calculation of innovation allowances.	**High**	Given the increasing importance of innovation, we believe the IMs should provide a high-level innovation allowance framework that can guide the detailed allowance setting in each determination. The IRIS needs refining to allow capex cost savings in future regulatory periods that have resulted in investments made in the current regulatory period (innovation or purchase of flexibility services), to be rewarded.
Customers will become more reliant on the electricity network as more of their energy is provided by the electricity network. Customers DER means that customers will want to use electricity in new ways that may require new	**Expanding quality measures**: An important part of incentivising innovation is to ensure that distribution services are providing what customers want – that EDBs innovation programmes are focused on providing benefits that customers value. Appropriate quality measures will help guide an EDBs innovation focus by incentivising what customer value. The current SAIDI/SAIFI measures for high voltage reliability will not capture other elements of distribution services that customers will find important in the future.	**Medium**	As per our submission to the Information disclosure review, we support new quality measures provided that: 1. The measures reflect what customers want 2. The benefit provided by the information is greater than the cost of collecting that data. For example, measuring low voltage reliability would require a significant investment in low voltage monitoring, data storage and analysis. Will the benefits provided to customers of the associated quality improvements of measuring LV quality performance outweigh the investment cost? 3. That EDBs are appropriately funded to collect the information (e.g. significant investment in LV monitoring would be needed before networks could effectively measure LV reliability). 4. Any new measures support one of the four limbs of Section 52A (1) of Part 4 of the Act

Future efficiency and innovation drivers	Issue	Review priority	Possible solutions
quality aspects to be important – like power quality and a focus on low voltage quality.			5. The information collected aligns with price/quality regulation – the information collected aligns with the level of quality that customers are willing to fund and EDBs are funded to provide.
Networks investing at the same time as other utilities – opportunities to share ground works.	Combining civil works costs with other infrastructure projects (like water infrastructure projects) may provide opportunities to share costs and reduce disruption through multiple excavation projects. In Wellington, water infrastructure projects are often excavating the same corridors as is needed for future underground cable replacements. However, current regulatory capitalisation rules can prevent EDBs from investing, even if it is the most efficient option. If the cable replacement/ducting cannot be used immediately (there maybe a wait until connecting works are completed or cables required, often years in the future) the project works will sit in WIP and an EDB will not get a return on that investment until its capitalised – the EDB will not be able to recover the funding cost between the works being implemented and the asset being capitalised.	**Medium**	Provide the ability to EDBs to recover funding cost for assets sitting in WIP.

3.2.2. Incentive mechanisms to improve expenditure efficiency for EDBs and Transpower

Incentives to promote efficient expenditure is a core objective for Part 4 regulation. The IRIS mechanism forms an important decision-making tool at Wellington Electricity as we make expenditure decisions in relation to our allowances. However, we do find the IRIS mechanism complex and difficult to use, often leading to uncertainty for clear decision making. The opex IRIS mechanism is especially complex when on a CPP and can result in large IRIS revenue adjustments from relatively small cost movements[5].

Importantly, the IRIS does not allow a network to be rewarded for capex cost savings that may occur in future regulatory periods. While the IRIS is designed to make investment decisions agnostic about whether expenditure was made using opex or capex, the offsetting incentives and penalties only apply within the same regulatory period. For example, an EDB purchases flexibility services using operating expenditure (a cost that the current allowance calculation does not provide), which delays the need to make a capital investment for five years. The capital investment was planned in the next regulatory period – flexibility services will be purchased well before an investment is needed to provide EDBs time to plan and build the new capacity before its needed. The IRIS will penalise the EDB for overspending their opex allowance but will not be rewarded for delaying capex expenditure because the capex forecast for future regulatory periods will include the expected impact of the flexibility service (the expenditure forecasts provided in asset management plans must be based on management's best forecast of future demand, capacity and investment requirements).

As highlighted in case studies 2 and 3, flexibility services will be a necessary tool for EDBs to help to deliver the ERP related demand increase. Flexibility services are expected to reduce costs by delaying expensive network reinforcement. Case study 3 highlighted the value that could be provided to Wellington customers by using the services. Flexibility services will only be effective if networks are correctly incentivised to use flexibility services when it is efficient to do so. This includes:

- Incentivising EDBs to invest in developing flexibility services and the tools and processes needed to use them.
- Incentivising EDBs to purchase flexibility services when its efficient to do so.

Table 2 provides the future drivers of expenditure efficiency, how they influence the key issues and prioritisation of those issues. Some high-level solutions are also provided.

[5] Due to the CPP Opex IRIS mechanism recognising the customers benefits during the CPP period, rather than when the benefits are passed to customers like on the DPP.

Table 2: Expenditure efficiency

Future expenditure efficiency drivers	Issue	Review priority	Possible solutions
Opex/capex substitution will become more important with the introduction of flexibility services Networks will need to invest in a combination of wire and non-wire solutions – the most appropriate solution depending on the timing of when new capacity is needed and the procurement response to a call for flexibility services.	The IRIS mechanism is complex, devaluing its effectiveness in incentivizing cost savings - the complexity makes it difficult to be certain of an investment outcome – an investment maybe avoided because of the uncertainty of relying in the IRIS to recognise the investment benefits.	**High**	The IRIS is an essential tool to promote cost efficiency and innovation. The review should look for opportunities to simplify the IRIS mechanism and reduce revenue volatility. We also believe that a totex regime like that used in the UK should be explored. It may provide a more effective alternative. This is a complex topic, and we believe an additional workshop step using subject experts is needed.
The owners of EDBs will expect stable returns for their increasing investment	Private owners of utilities often invest for the stable returns that a regulated infrastructure business provides - there is an expectation of stable year on year dividends and profits. The IRIS mechanism makes it difficult to invest in efficiencies savings because the resulting incentives can create volatile revenue fluctuations and returns. • IRIS adjustments often continue for years after allowances were under or overspent. The revenue volatility can cause EDBs to avoid an efficient investment decision because of the impact on financial stability • Often a long wait to receive the benefits of an investment – for example, a network may have to wait seven years to see Capex IRIS benefits (the time difference between the firsts year of a determination and to when the capex IRIS is calculated). • The IRIS adjustments for opex/capex substitutions are years apart - EDBs have to balance the decision to substitute expenditure with	**High**	The review should look for opportunities to and reduce revenue volatility: • Allowing the costs and benefits of an investment to be more closely matched • Allowing the IRIS adjustments of substituted opex and capex to be more closely matched. This is a complex topic, and we believe an additional workshop step using subject experts is needed.

Future expenditure efficiency drivers	Issue	Review priority	Possible solutions
	whether they can also find ways of offsetting short terms reductions in revenue and return.		
Flexibility services will make it more important to reflect cost saving benefits across multiple regulatory periods	Flexibility services are likely to be of the most benefit for delaying network reinforcement planned for at least 4-5 years way which is likely to fall in the next regulatory period. EDBs will need to start planning for and implementing investments needed earlier than 4-5 years – the timeframes being too short to confidently delay or avoid using flexibility services. The IRIS would not capture the capex IRIS benefit from delaying an investment which is planned in the next regulatory period.	**High**	Review the IRIS regime to ensure all benefits are captured
ERP will drive more customer connections - growth that is outside of an EDBs control and could be more than regulatory allowances provide for	New customer connection growth is outside of the control of EDBs. However, the IRIS penalises networks if new customer growth and the resulting expenditure is more than the allowances provided, or rewards EDBs if the expected growth does not eventuate – the penalties and rewards are primarily based on customer decisions and are mostly unrelated to cost efficiency.	**Medium**	Customer driven capex should be excluded from the IRIS.
Inflation is forecast to be significantly higher than the monetary policy target of 2%	The IRIS targets are not adjusted for inflation – inflation is treated as a cost inefficiency that they must fit within their expenditure forecasts.	**Medium**	Include an inflation adjustment in the IRIS targets.
The impact of IFRS 16 on the IRIS	The application of IFRS 16 has added complexity to the IRIS calculation and requires the additional ongoing maintenance of assets and costs as though IFRS 16 never happened. The requirement to forecast future lease costs and right-of-use capitalisation when determining the "trend" allowances for IRIS creates additional forecast error.	**Low**	Review the requirement to adjust for IFRS 16 and exclude this added complexity.

3.2.3. Form of control (short-term demand risk)

The form of control for short term demand risk has been recently changed to a revenue cap and WELL continues to support moving from a weighted average price cap. We have found the downside risk to customers of using a revenue cap (price volatility) has been limited. The difference between actual allowable revenue and actual revenue has been less than +/- 1.5% since we moved to a revenue cap in 2018 (the exception being this year's results (currently being audited) which will show a greater than 1.5% variance due to Covid related demand changes and the faster than expected EV uptake).

The 2016 IM review addressed the reasons for moving to a revenue cap in detail and we do not believe that the drivers behind those reasons have changed to the extent the subject needs to be reviewed again. However, we do believe that the mechanism can be refined, and adjustments made in a similar way to how the Aurora CPP decision incorporated this into the IMs.

Table 2: Short term risk

Drivers impacting characteristics of short-term demand risk	Issue	Review priority	Possible solutions
Impact of high inflation and high transmission investment on financeability	The current revenue cap has a 10% cap on annual price increases – any increase over this will get smoothed into proceeding years. Businesses still need the cashflow provided by regulatory revenue to finance and operate business activities. If network investment is smooth and capex and depreciation is balanced, then businesses can borrow to support revenue smoothing. However, like now, if capex is more than depreciation (periods of high investment), then allowances maybe less than an EDB needs to finance their business and an EDB maybe limited in being able to support revenue smoothing (limited in its ability to fund the temporary revenue reduction). Under the current revenue cap, inflation and increases in Transpower costs are also included in the revenue cap – EDBs will have to find further funding if increases to these cost inputs outside of a networks control contribute to revenue exceeding the 10% limit.	**High**	• Exclude Transpower cost increases and inflation uplifts from the revenue smoothing calculation by applying the Aurora CPP revenue cap design. • Include a financeability assessment like that used by overseas regulators including Ofgem/Ofwat/IPART. The assessment tests whether the regulatory allowances provided will allow a network to finance their business activities and to stay solvent.

3.2.4. Longer-term demand risk

As we will show in case study 4, the risk the stranded assets due to declining volumes on the Wellington network is low. We do not believe more of the long-term demand risk should be shifted to suppliers as customers would then pay a premium for a risk that seems unlikely to eventuate. If new technology is developed that could strand significant proportion of a distribution network, the potential impact would be large enough to consider changes to the IMs at that time.

The greater risk is under investing in network capacity when assets are upgraded, and the upgraded capacity is not enough to meet new demand growth over the life of the asset. This could 'strand' the upgraded asset – the asset would need upgrading again and the customer would still be paying for the old asset while also paying for the new upgraded asset. This risk increases if there is uncertainty in future demand forecasts at the time an upgrade investment is being made – like the uncertainty about the treatment of natural gas and the potential impact on future demand. As we will show in Case Study 4, whether the electricity network becomes the gas substitute could impact the electricity demand forecast by 48%.

Network operators will need to carefully balance how much capacity they build when upgrading assets:

- to avoid gold plating and building more capacity than is needed (ahead of EV uptake rates or other demand drivers); or
- creating a stranded asset because an asset has insufficient capacity to meet future demand and has to be replaced early with more capacity to avoid curtailing new demand or compromising quality of supply.

Along with regulatory flexibility to adjust when to invest (adjusting work programmes to changes in demand), we believe EDBs will also need the flexibility to adjust their investments to reflect changes in network capacity in response to changes in demand forecasts. With this flexibility the risk of stranded assets due to faster than expected demand growth should be minimised (and the treatment of long-term risk can be maintained).

Table 4: Long term risk

Drivers impacting characteristics of long-term demand risk	Issue	Review priority	Possible solutions
Uncertain demand growth	Over investing in too much capacity and gold plating or; Underinvesting and creating a stranded asset because assets have to be replaced early if they can't meet future demands growth.	**Medium**	Allow networks more to flexibility to adjust their investments to reflect changes in network capacity in response to changes in demand forecasts.

3.2.5. RAB indexation and inflation forecasting

The treatment of inflation in the regulatory framework is complex and the impacts of forecast error are material. The issues were presented to the Commission in April 2021 by Aurora, Orion, Powerco, Unison, Vector and Wellington Electricity and have been covered adequately in the Process and Issues paper. We support considering options that would reduce the impact of forecast error on an EDBs ability to earn real FCM, and to improve the accuracy of inflation forecast when they are needed. At this stage we do not have a solution preference.

We also have concerns about the treatment of inflation when transitioning between price paths:

- Maintaining consistency between the inflation inputs
- Reducing the time between when actual inflation is used to update a forecast

Table 5: RAB indexation and inflation forecasting

Drivers impacting inflation forecasting	Issue	Review priority	Possible solutions
Material inflation forecast errors	**Inflation forecasting:** New Zealand has been through a period of low inflation and the inflation forecasts used have tended to over forecast inflation. EDBs have not receive the efficient real return on equity required in order to attract equity capital. This is because an over-estimate of investors' true inflation expectations results in too high a forecast of the inflationary gain in the RAB being deducted when the Commission sets EDBs' return on capital allowances. New Zealand is now entering a period of higher than forecast inflation and some of the lower-than-expected return of equity is being offset. We do not know whether the risks is symmetrical or whether there is still an underlying bias towards over forecasting inflation overall by using the monetary policy inflation forecast.	**Medium**	• Consider options to reduce the impact of inflation forecast error. • Consider options to improve inflation forecast accuracy where inflation forecasts are used.
	Debt compensation: EDBs issue nominal debt and are contractually required to pay nominal interest costs, but the regulatory framework delivers only a real return on debt capital in each regulatory period. If EDBs have no effective way of aligning their actual cost of debt to the real return on debt allowance provided by the regulatory framework, then equity investors are forced to make up any shortfall if actual inflation	**Medium**	• Options to consider include a hybrid RAB indexation model • Consider allowances to purchase inflation indexed debt (if these debt instruments are available).

Drivers impacting inflation forecasting	Issue	Review priority	Possible solutions
	turns out to be less than forecast by the Commission or gain if actual inflation turns out higher than forecast by the Commission.		
Transition between price paths	As highlighted in WELLs determination decision for its transition from the CPP to DPP in November 2020, there are restrictions on the ability for certain inflation components to be updated which can create inconsistencies of outcomes when differing inflation components are used. This was highlighted in our submissions on our draft default price-quality path. Additionally, due to WELLs 1-year delay in the transition to the DPP3, WELL has faced increased forecast error impacts as a result of the time lag between the start of DPP3 and the forecast inflation inputs used in the setting of WELLs "forecast net allowable revenue". At the time of our draft decision WELL highlighted that the inflation forecasts, due to the unprecedented impact of Covid, were highly volatile. This volatility has been highlighted by the current economic conditions with annual inflation running at 6.9% for the March 2022 quarter, well above inflation forecasts at the time of setting WELLs determination. This volatility means that in applying the "forecast net allowable revenue" in our first year of the DPP we have worn over 2-years of forecast inflation risks which means our allowable revenue has not been uplifted in line with the large increases in inflation driven actual costs. This issue will only be exacerbated for EDBs transitioning back to DPPs in the latter years of the regulatory period.	**Medium**	• Consider opening all inflation components when setting an out of cycle Determination. This would include setting a new WACC.

3.3. Issues relating to the cost of capital

EDBs will be required to make a step change in network investment (see case study 4). Investor confidence must be maintained so that suppliers have an incentive to increase their investments in distribution networks. Practically this means providing investors with confidence they will earn a risk adjusted cost of capital.

This starts with ensuring that WACC captures what is a fair market measure of the cost of capital. We support using a well understood calculation method to provide consistency and certainty about the expected outcome. However, the world is experiencing unusual economic conditions (volatile inflation, negative real interest rates etc) that may mean using a ridge application of the WACC calculation methodology could result in a WACC that is not consistent with the wider markets from which investors select their investments. We ask that the inputs and outputs to the WACC calculation are reviewed to ensure they make practical sense and reflect a workably competitive market. The consequence of underinvestment has increased now that distribution networks have been given the additional responsibility of enabling key components of the ERP which removes substitute energy choices from customers (oil, natural, gas and coal) and will make the electricity New Zealand primary energy source.

Table 6: Cost of capital

Drivers impacting WACC	Issue	Review priority	Possible solutions
Step change in investment and greater reliance on the electricity network	WACC percentile **-** The methodology used to calculate the WACC percentile is well understood. The consequence of underinvesting has increased with an increasing dependence on the electricity network (due to the transition away from fossil fuels and the central role electricity is playing in New Zealand ERP).	**Low**	Recalculate using updated inputs
Debt issuance costs	The Process and Issues paper asked whether debt issuing costs were being double counted. We can confirm the debt issuing costs are included as an addition to the cost of debt and are not included as an operating cost	**Low**	Maintain a debt issuing component
Volatile economic inputs	Update using the current calculation methodologies, reviewing the outputs to ensure they are economically sensible.	**Low**	Recalculate using updated inputs and sense check

3.4. CPPs and in-period adjustments to price-quality paths

Chapter 7, '*CPPs and in-period adjustments to price quality paths'* focuses on how much flexibility the IM's and the wider regulatory frameworks need to respond to an "upcoming period of rapid change in the policy environment and technology[6]". We believe that significant investment in flexibility is needed due to the inherent uncertainty of when the ERP related investment will be needed and the impact that non-wire services will have.

The current regulatory framework of providing a DPP for business-as-usual levels of investment and a CPP for a step change in business activities, works well for networks using traditional 'wire' operating models, supporting modest demand growth and delivering well understood asset replacement cycles. The funding for network growth and regular fleet replacements can be managed to meet forecast growth rates and well understood asset performance profiles. The traditional and predictable investment profiles can be forecast well in advance of actual expenditure and can be generally managed within five yearly regulatory periods.

[6] Section 7.1 of the Process and Issues Paper

The significant increase in demand from the decarbonisation programmes and the change from the traditional response to increasing network capacity by building a larger network, to also using new technology to better utilise the existing network capacity, means that the future environment of climate change adaption does not have the predictability and certainty of the past.

EDBs will need better visibility and oversight of their networks so they can adapt and change their investment profiles to match changes in customer demand. For example, visibility of LV assets is needed as much of the future growth will occur at the ICP level (brownfield growth) than HV extension and new network "greenfield" building. LV investment profiles will need to adapt to changes in customer DER uptake and how they use those devices (i.e. whether they export any excess electricity).

Regulation needs the ability to adjust and flex when allowances are provided so they match changes in an EDBs investment profiles – if demand grows faster than expected, network operators can bring forward investment, providing new capacity earlier to maintaining network security and reliability. If demand is slower, then investment can be efficiently delayed – efficiently in terms of moving that investment package within and between regulatory periods without incurring further regulatory costs.

Flexible regulation is important to customers to ensure that investment in new capacity can move to meet demand changes and are not made earlier than necessary (customers paying more than is needed) or later than is required (and reliability is impacted). The development of flexible regulation is a priority IM issue for WELL.

This submission presents two case studies to demonstrate the changing characteristics of future investment profiles. The case studies (case study 4 and 5 are provided in the appendices) will be used to illustrate what corresponding changes in the regulatory framework are needed to allow that investment to be continued to be made efficiently.

Case study 4 summarises the changing characteristics of WELLs future investment forecast. Changes include:

1. **Material step change, significantly larger than historic average:** We are forecasting a 108% increase in demand by 2052 on the Wellington network. Modest network growth and well understood asset replacement cycles has meant the Wellington network has historically had capacity to match demand, and customers have enjoyed low prices. However, this also means network does not have the spare capacity to meet the step change demand increase and new capacity will need to be built. Forecast investment increases from an average of $32m p.a. to $72m p.a. – a material step change from business-as-usual investment.
2. **Sustained across multiple regulatory periods:** Like other EDBs, WELLs investment programme will be required to deliver new capacity and continue to replace assets as they approach their useful lives to maintain network reliability, security and power quality. Unlike past step changes in investment that could be ring fenced into a single regulatory period (Powerco's, WELL's and Orion's CPP programmes), the size and timing of future ERP related investment will require a sustained increase in investment across multiple regulatory periods.
3. **Front loaded:** The investment is front loaded with the highest investment being in the first 10 years. This is because the existing high voltage network (particularly the 33kV sub-transmission network) does not have the capacity headroom available to deliver the rapid early network growth and growth over the rest of its 45-year useful life.

4. **Significant LV network reinforcement:** Investment in the LV network will also be needed. Investment in LV visibility will be needed immediately to enable the network planning team to assess whether customers can safely and securely connect customer DER.
5. **Growth will also come from existing connections:** Much of the demand growth will come from EVs and (potentially) transitioning from fossil gas to electricity and will be delivered from existing connections.
6. **Majority of expenditure will be from reinforcement of the existing network:** 53% of WELLs forecast investment is expected to come from reinforcement of the existing network, replacing existing assets with assets with more capacity. Brownfield network reinforcement is more expensive than greenfield because of the complexity of working within existing infrastructure.
7. **Opportunity for flexibility services to value stack within the network:** Significant value can be provided by flexibility services if shifting peak demand helps defer network reinforcement at the 33 kV, 11 kV and low voltage networks. Networks will need to develop network planning and demand management tools to identify where flexibility service will provide the most value.

Case study 5 takes a closer look at the underlying uncertainty of WELL's future investment forecast:

1. **Uncertain investment drivers**: While EDBs can be confident that a significant increase in investment will be needed, the timing and the capacity of the new investment will be uncertain due to uncertain investment drivers:
    a. What the future substitute for fossil gas will be? When will it be confirmed whether it will be electricity or not?
    b. Whether flexibility services will be developed to the scale needed to better utilise the existing distribution network? Even if the services are developed, how predictable will the demand response be?
    c. What will the uptake speed of customer DER, particularly EVs, be?
    d. Will customer DER provide a more cost-effective solution than upgrading rural or isolated networks? If so, when will the technology provide a viable alternative?
2. **Quickly changing demand**: Some of the underlying drivers of changing demand could change demand quickly with little lead in time for networks to adjust their investment forecasts and allowances calculations. Significant changes in investment requirements (both increases and decreases) could occur within a regulatory period. Networks may have to adapt their investment profiles within a regulatory period for demand uncertainty relating to the uptake of customer devices (like EVs) that can increase demand quickly.
3. **Uncertain resource availability:** The availability of resources may also impact the timing of an investment. EDBs may need the ability to shift when they can build new assets to when resources are available.
4. **High value in being able to closely match capacity and demand:** The cost of building early or building late are high. There is value in EDBs being able to flex their investment programmes to match changes in demand as closely as they can while still maintaining network security and reliability.
5. **EDBs will have to invest in new tools and capability:** New tools and capability are needed to allow EDBs to manage uncertainty – to closely match demand with capacity. EDBs will need

visibility of their LV networks, demand forecasting tools and the ability to call on and incorporate flexibility services.

Table 7 takes the key characteristics of future investment identified in the case studies and highlights the issues with applying the current regulatory framework. The summary also provides possible solutions. The case studies show that the investment characteristics that the current regulatory framework is designed for, will no longer match EDB future investment profiles. The objectives of Part 4 52A would not be meet because:

1. EDBs would not have the allowances (and therefore incentive) to invest in the network when they are needed (Part 4 52A (1)(a)) and could incur incentive penalties in response to uncertainty outside of an EDBs control.
2. Without allowances to invest then EDBs may not be incentivised to maintain service quality or may be incentivised to invest earlier than is needed to maintain quality but at the expense of higher prices (Part 4 52A (1)(b)).

Changes are needed to the overall regulatory framework that allows investment profiles to flex and adjust to changes in the underlying investment drivers. This could mean a different approach to the current DPP/CPP model of discrete, ring-fenced price paths based on five-year regulatory periods. Networks will need the ability to move investment packages between regulatory periods in response to changes in the underlying investment drivers. Flexibility is also needed to adjust the size of investments to reflect any change in the underlying capacity requirements. Changes to the regulatory framework could include:

- Investments that are uncertain to include triggers to alter when that investment is needed. Those triggers could reflect uncertain delivery inputs (e.g. resource availability) or uncertainty about when the capacity is needed (i.e. changes in demand).
- Investments that are uncertain to include triggers to alter the size of the investment. The trigger could reflect changes to an investment's capacity requirements in response to changes to the demand forecast – i.e. if the demand forecast increases and the capacity of the assets being installed also needs to increase, then a demand-based trigger event could be used to allow the investment to be adjusted.
- The ability to move investment packages between price paths, avoiding expensive regulatory costs.
- Streamline price path, reopeners and contingent investment assessments to allow networks to quickly and confidently adjust their investment profiles.

Table 7: CPPs and in-period adjustments to price-quality paths

Investment characteristics	Issue	Review priority	Possible solutions

Fundamental change in a network's investment focus – moving from an environment of steady or declining demand (limited need for large new investments in capacity) and a strong focus on network integrity investment (the traditional triggers for a CPP) - to a material step change in investment in new capacity:
• sustained across multiple regulatory periods
• Front loaded and will be needed shortly
• High levels of timing uncertainty
	Overall, we believe the investment characteristics that the regulatory framework is designed for, will no longer match EDB investment profiles:
	• There will be no business-as-unusual profile for the current DPP approach - investment profiles will differ between networks as electricity demand increases at different rates depending on existing network capacity and different demand drivers. The DPP restrictions may need expanding or CPP price path applications may be unmanageable.
	• The CPP application process will also need more flexibility to allow for investment uncertainty, applications to cover multiple regulatory periods to cover sustained levels of investment.
	• Investments will no longer be able to be ring fenced into discrete five-year investment programmes – investment uncertainty will mean investment packages will move between regulatory periods – and potentially in and out of different determinations (between DPPs and CPPs).
		High	An overall regulatory framework that allows investment profiles to flex and adjust to changes in the underlying investment drivers - the ability to move investment packages between regulatory periods in response to those changes. Possible solutions could include:
			• Breaking investments into investment packages that could move between price path determinations. The investment packages could be categorised into levels of uncertainty:
			  ○ Low uncertainty investments, like asset replacement, could be treated as it is now – based on a forward looking forecast and cost efficiencies encouraged using the IRIS.
			  ○ High uncertainty investment, like network reinforcement that is dependent on volatile demand forecasts, could be packaged and made contingent on a trigger (like reaching a certain demand point or the availability of resources). These investment packages could be transferred between regulatory periods if needed, without the need to reapply or re-assess, avoiding further regulatory costs.
			• Heatmaps could be used to show where and when network congestion will occur

Investment characteristics	Issue	Review priority	Possible solutions
	Specifically, the current CPP Determination is not suited for sustained investments across multiple regulatory periods • Part 4 only allows one CPP submissions, covering one regulatory period to be made at once. Networks will be required to make a step change in investment that is sustained across multiple regulatory periods. The demand uncertainty will mean that some of that investment could move between regulatory years and periods. It will be difficult to ring fence and cut the investment programmes to fit a standalone CPP programme. • Investments initially planned for the last two years on a CPP that are then delayed, until the next regulatory period could trigger the need for another CPP, delaying the investment while the application is made – potentially impacting reliability and network performance • The high, non-recoverable, CPP application costs makes it expensive to make continuous CPP applications. Regulatory costs will significantly increase as multiple CPP are made.		• Using an IPP for networks with large sustain investment profiles. The IPP 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.
	DPP is based on backwards looking allowance calculations for both the capex gates and opex allowances. As illustrated in the case studies, future investment profiles will differ significantly to past expenditure patterns. The approach of basing future allowances on past patterns used to develop DPP Determinations will need to change, or there will be few networks able to sensibly use the DPP Determinations. While this is a DPP Determination topic, it is important to develop an overall regulatory design and strategy that will		Include the ability to provide allowances for new expenditure types. This could be achieved by using: • the AMP opex forecast with a high level of scrutiny • a base-step-trend approach like that used in Australia • refine the IRIS to allow the more effective and less volatile substitution of opex and capex expenditure Submission to the DPP3 reset provided a range of different solutions that could be considered as part of the overall design of the regulatory framework.

Investment characteristics	Issue	Review priority	Possible solutions
	provide the allowances when they are needed under changing investment characteristics, while promoting Part 4 objectives. For example, the design or approach taken to develop the DPP4 mechanisms will influence how many networks may need to move to another price path which in turn could influence the design of the CPP.		

Uncertain and quickly changing investment timing	• As shown in the case studies, EDBs will need to be nimble about when they invest to ensure that investments in new capacity are made before the capacity is needed (to maintain supply security and reliability), made when resources are available and as close to reasonable to when the new demand is needed to limit the risk of customers paying for capacity that is not utilised.
	• The current CPP has a contingent project reopener and an unforeseen project reopener which do provide some flexibility. However:
	  ○ The contingent project reopener is limited to within period investment – another price path application would be needed if that investment is not triggered when expected and has to move into the next regulatory period.
	  ○ The unforeseen project has a very high threshold that would not be triggered for investments moving in and out of a regulatory period.
	• Both reopeners would require an application to the Commission. The new DPP3 large customer connection reopener shows this to be a long process (12 months for the Unison application) which would be to slow for some investments.
		High	Demand profiles and the level of investment uncertainty (when investments will be required) will differ between networks. We believe a range of solutions will be needed that will allow an EDB or the Commission to choose which is best suited for a specific investment programme. Solutions could include:
			• **Contingent allowances:** for investments that have a high level of timing uncertainty. It would be important to reduce the criteria from the current CPP mechanism to allow it to capture a larger proportion of a network investment programme. Contingent allowances could be used in both the DPP and CPP, but it would be important to have the ability for an investment package to move between price paths or regulatory years**.**
			• **Extend the use of re-openers:** to unforeseen network investment caused by incremental demand growth, rather than just large new connections.
			• **Single issue CPP**: allow a 'streamline' CPP like WELL's earthquake readiness programme. A network would remain on a DPP for its business-as-usual operations and the higher level of CPP scrutiny would apply to a specific investment programme.
			• **Extending the DPP capex gating limits**: allowing the DPP to flex with the increasing investment requirements. Specific gate changes could include reducing the network reinforcement restrictions as networks build more new capacity.

Reopeners	Reopeners are an effective tool for capturing unforeseen events – like unexpected new customer connections.	**Medium**	• Refine the DPP and CPP reopeners to streamline the process and to capture opex costs.

Investment characteristics	Issue	Review priority	Possible solutions
	Unisons recent application and our own application development (yet to be submitted) has highlights areas where the mechanism needs refining: • The assessment process is to long – Unisons application took 12 months for the application to be assessed and for the price path to be re-opened. EDBs will need to be nimble to adjust their investment programmes to quickly changing capacity constraints. • We question the need for a public consultation for applications where the connecting customer is funding the majority of the connection costs and has agreed to the commercial terms. We understand the need for a consultation phase if there is an element of network reinforcement that will be funded using mass market tariffs (i.e. the investment also provides benefits to the wider network). • The current re-opener excludes opex expenditure. This restriction limits any network solution to traditional wire network designs and excludes using flexibility services that could provide a more efficient option. It also excludes the ability for an EDB to recover any related opex costs like insurance increases.		• Consider new reopeners for network reinforcement caused by incremental increases in demand growth (e.g. EV growth or customers converting from using gas to electricity).
All networks investing - price path and reopener application times	EDBs may need to make quick decisions about when to invest – this maybe in response to: • A flexibility service that has not responded as expected • Quicker than expected demand from a rapid uptake in customer devices like EVs • An unforeseen large new customer connection • Resource unavailability As networks change and adapt their investment profiles, they may need to apply to the Commission for a new price	**High**	Consider ways of streamlining assessment processes: • Standardise the CPP verification and approval process where possible • Increase Commission's resources to enable faster application assessments and the assessment of more applications. • Reconsider when assessments may not be needed – or when a light-handed assessment may suffice. For example, a public consultation may not be needed for new connection reopeners where the connecting customer has agreed to fund the connection and other customers are not impacted. • Workshop ideas to streamline assessment processes.

Investment characteristics	Issue	Review priority	Possible solutions
	path or additional funding via a reopener. The current application, verification and consultation process takes a long time and could be too slow for future investments: • The Unison reopener took 12 months to approve • A CPP application has historically taken approximately 2-3 years to develop and assess		• Looks to other jurisdictions for ideas.
Networks owners will be expected to make a significant additional investment in their networks. To make this investment, they will need to be confident they will be appropriately rewarded for that investment.	Refer to "Transition between price paths" in Table 5 above, where concerns were raised about the timing and inflation risks born by the EDBs during periods of transition between price paths out of the normal regulatory cycle.	**Medium**	Consider opening all inflation components when setting an out of cycle Determination. This would include setting a new WACC.

4. Closing

WELL appreciates the opportunity to provide a submission on the Commissions Draft Framework and Process and Issues Papers. These consultations and last years '*Open letter—ensuring our energy and airports regulation is fit for purpose'* provide an important step in defining what the priority issues are – the key issues that need to be resolved to allow EDBs to continue to provide a secure and reliable distribution services, at a price customer are willing to pay.

The ERP will make this challenging as networks move from an environment of stable or declining growth, focusing on refining existing practices and improving efficiencies, to an environment of:

- high and uncertain demand growth,
- new customer services as customers purchase DER with two-way power flows,
- new operating practices using non-wire solutions; and
- increased reliance on electricity as it becomes New Zealand's primary energy source.

The supporting regulatory model and approach will also need to adapt – the regulatory model will need to evolve from a primary focus on cost efficiency to also considering how to support the innovation and investment growth that is needed. Consideration will also need to be given to how to capture and consider the future benefits that networks will enable outside of what is captured by distribution price and quality – like meeting New Zealand's emissions reduction targets and allowing customers to avoid other expensive fossil fuel energy costs.

The issues are complex, and we believe an additional process step is needed to develop solutions for some of the more complicated subjects. We suggest using small industry working groups using topic experts to develop solutions that could then by presented publicly for consultation. There is time to run those workshops in quarter three this year.

If you have any questions or there are aspects you would like to discuss, please don't hesitate to contact Scott Scrimgeour, Commercial and Regulatory Manager, at scott.scrimgeour@welectricity.co.nz .

Yours sincerely

Greg Skelton

Chief Executive Officer

5. Appendices

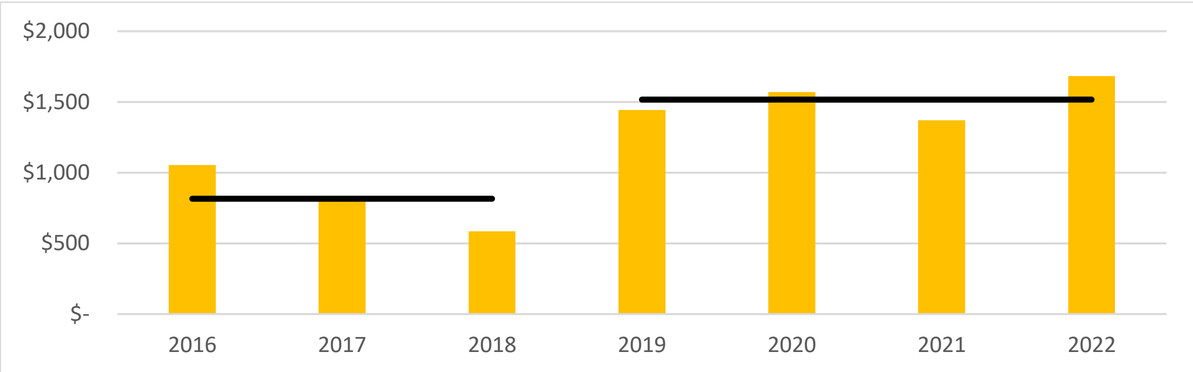
5.1. Case study 1: Cost increase without a measured productivity improvement

WELL has been funding above inflation cost increases that do not result in improvement in the productivity measures used in the Process and Issues paper productivity analysis. The cost increases have been funded by finding cost saving elsewhere or from shareholder returns. This case studies provides examples that illustrate the different reasons costs may increase while not improving the productivity measures.

Impact of the Health and Safety at Work Act

The introduction of the Health and Safety at Work Act has resulted in a number of operational changes that have added costs with no associated productivity benefit. Traffic Management practices have significantly changed with the introduction of the Act – traffic management plans are now more complex and require more staff and equipment to implement. Traffic management costs have now become a significant proportion of a jobs total cost. For example, of the recent Fredrick Street (central Wellington) high voltage underground cable replacements total cost of $8m, traffic management made up $1m or 12.5% of the total cost. Figure 2 shows the change in average cost per job (black lines) from before and after the Act took effect on work practices in 2019. The example used is from our reactive maintenance programme that is not priced using fixed rates.

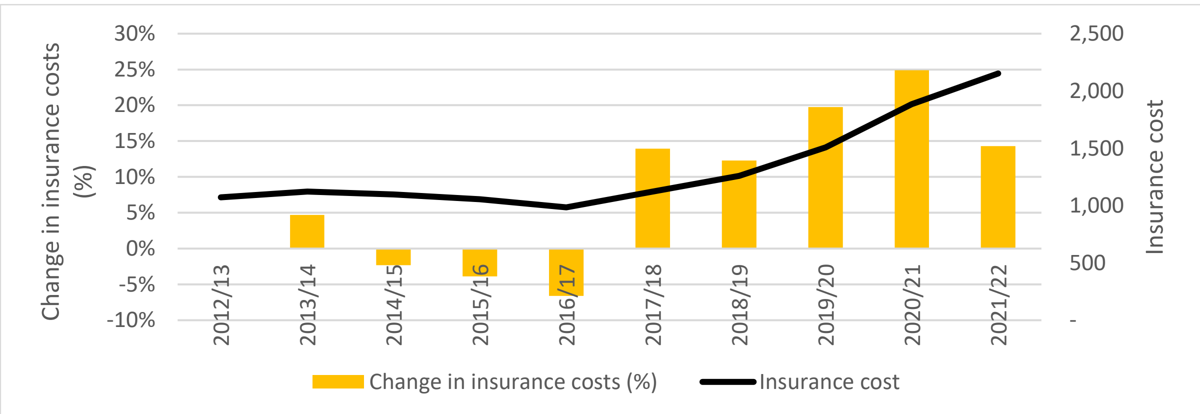
Figure 2: Traffic management costs per job



Insurance costs

Insurance costs in Wellington have increased significantly following the Christchurch and Kaikoura earthquakes as insurance providers reassess the natural disaster risks in New Zealand. Figure 3 show the change in insurance costs. The above inflation insurance cost increases have no associated productivity benefits.

Figure 3: Insurance costs



The 11 July 2022 NBR article titled 'Insurer wants better response to climate change impacts' highlights the increasing damage from natural disasters and suggest that insurance prices could continue to increase.

ERP related preparation

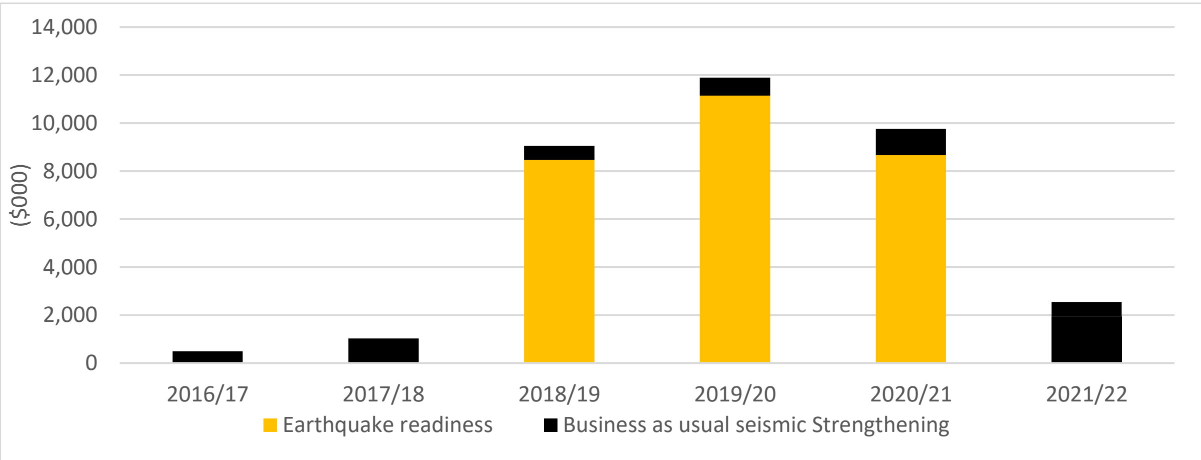
Since 2018, we have been preparing for the expected rapid uptake customer DERs like EV's. More recently this has expanded into how to prepare for the ERP related demand increase. Preparation has included research and development into trials to understand EV use and pricing to encourage off peak use. More recently our research and development has focused on developing flexibility services and ways we can support those in energy hardship. Expenditure on these programmes has not provided immediate productivity benefits but will be essential for delivering future ERP relate demand. ERP related innovation programmes include:

- 2017 Household solar/battery trial – testing the effectiveness of using a household solar/batteries to offset household peak demand
- 2018 EV Charging trial - understand the home charging behaviours of EV owners
- 2018 EV charging ToU prices – trialling prices to shift EV charging away from network peaks
- 2019 Cost reflective prices – prices that reflect the cost of using energy during network peaks
- 2021 EV Connect – developing a managed EV charging flexibility service
- 2022 FlexForm – Developing flexibility industry trials

Earthquake readiness and resilience

WELL has invested in seismic strengthening capital works following Building Act changes requiring buildings to be upgraded to meet minimum seismic standards. WELL also invested in an earthquake readiness programme following an earthquake readiness audit of Wellington utilities after the Kaikoura earthquake in 2016. Figure 4 provides the resulting capital expenditure. The earthquake readiness programme also resulted in $0.6m p.a. in ongoing operational expenditure. This expenditure will not provide productivity improvements using the productivity measures in the Process and Issues paper analysis.

Figure 4: Earthquake readiness and resilience capital expenditure

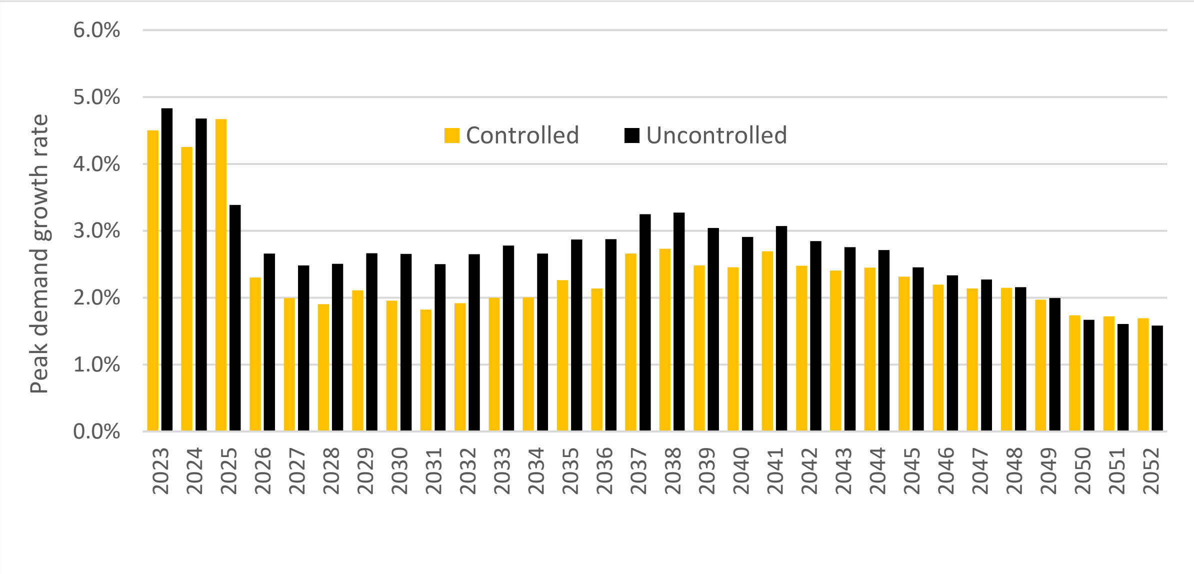


5.2. Case study 2: value and importance of non-wire solutions (flexibility services)

WELL has a strategy of developing flexibility services to reduce the impact of network growth on peak demand – services which allow electricity use to be shifted away from congested periods on the network, reducing peak demand and reducing the level of network reinforcement needed.

We have been modelling the demand and investment impacts of ERP[7]. The scenarios we have modelled include the impact of using flexibility services to shift peak demands (the controlled scenario) and the impact of not having flexibility services (the uncontrolled scenario). Figure 5 shows the reduction in peak demand growth rate if we can successfully implement flexibility services. Flexibility services provide the ability to reduce peak demand use and slow the initial rate of increase.

Figure 5: Forecast demand growth rates on the Wellington Network



Like the peak demand modelling, we have developed investment profiles which reflect a controlled scenario which uses flexibility services to compliment the traditional wire solutions. We have also developed an uncontrolled scenario which uses only traditional wire solution to deliver the future demand increase – what our future investment might look like if we cannot develop flexibility services. Figure 6 summarises the 30-year capital expenditure under the two scenarios. The controlled scenario defers an estimated $317m in capital expenditure over the 30-year planning horizon. This value will be passed to customers either by lower distribution prices or as a payment for purchasing flexibility services.

Figure 6: Capital expenditure summary

Scenario	Controlled	Uncontrolled	Difference
Total ($m)	2,027	2,345	(317)

[7] Our peak demand and investment modelling requires a high degree of judgement due to uncertain demand drivers like EV uptake, the success of flexibility service to shift peak demand and whether electricity will be the substitute for fossil gas use. Care must be used on how these figures are used as they are constantly being refined and updated as input change.

Flexibility services provide the ability to value stack within a distribution network – the highest value comes from using flexibility services to shift peak demand that is constraining the 33kV, 11kV and low voltage networks. Networks will need to develop network planning and demand management tools to identify where flexibility service would provide the most value. Figure 7 shows the value of deferring network reinforcement on example (using an average upgrade cost) 400v, 11kV and 33kV networks.

Figure 7: The allowance impact of building one year earlier than unnecessary

Network upgrade	400 v (low voltage)	11 kV (high voltage)	33 kV (sub transmission)
Build cost	0.1m	$3.2m	$25m
Incremental annual allowance	$0.06m	$0.2m	$1.6m

WELL has a current strategy of using load management tools to delay having to invest in building a larger network for as long as possible. Current load management tools include using the networks 'mesh' design to redistribute load, hot water ripple control and cost reflective pricing. Currently there are parts of the Wellington network where demand occasionally exceeds capacity, and we will use these demand management tools to shift demand to other parts of the network or to shift load to less congested periods. This has helped us maintain one of the lowest distribution prices in New Zealand while operating one of the most reliable networks. Flexibility services will provide another tool to enable us to continue to apply this strategy.

Case study 4 will demonstrate the step change in investment that will be needed to deliver the ERP. Our existing demand management tools and flexibility services will help provide us the time to build the additional capacity needed. The size and relatively short investment period (case study 4 will demonstrate that much of the investment is front loaded over the next 15 – 20) makes delivery difficult. Flexibility service will enable networks to spread out the investment into more manageable programmes (noting, the programme is still significant and will be difficult to deliver even if control is successfully applied).

The significant increase in network investment will also come at a time when other distribution networks, the transmission grid and other industries like water and transportation will also replacing, developing and growing their infrastructure in response to the climate change targets. A finite pool of skilled resource in New Zealand (and potentially globally as other countries reduce carbon emissions) could make this level of growth unrealistic if it can't be spread-out.

Case Study 5 will show that future demand growth will be uncertain. Flexibility services will provide us with some ability to mitigate demand uncertainty – flexibility services can be called on quickly in response to faster than expected demand increases, providing time to consider and plan for traditional wire solutions.

Case study 3: Funding needed to developing flexibility services

Our EV Connect project provides the actions and steps needed to implement managed EV charging flexibility services. The Roadmap allocates the actions to the flexibility participant who will be responsible for delivery. The Roadmap also categorises the actions into action layers (actions types) – the action layers being Leadership, Legislative and Regulatory, Functions, Commercial, Information, and Communication.

Many of actions that the Flexibility service buyer (an EDB being one of the buyers) require direct funding or innovation funding to purchase or develop a specific capability needed to use flexibility services. EDBs will need access to new funding for each of these actions. Figure 8 summarises the actions that will require access to new funding, provides a description of the action and the type of funded that is best suited. Note, only actions that require additional funding have been included in the figure – see full Roadmap for a complete set of actions.

Figure 8: EDB EV Connect Roadmap actions that need funding to deliver

Action layer	EV Connect Roadmap Actions	Action purpose	What the funding is needed for	Materiality ($ value)	Type of funding
Leadership	Establish co-leadership group	Establish a central leadership group to drive objectives, set outcomes and report (annually) on progress. A joint leadership team with a government authority (potentially The Electricity Authority) and industry representation.	Share in the cost to run and administer the working group	Small	Opex
Function-Flexibility services	Prototype managed EV charging service	Develop trials and pilots to test different aspects of a flexibility service and possible services.	Innovation allowance to run trial	Large	Innovation allowance
	Promote participation in new services	Promote customer participation to provide the scale needed for flexibilities to become a viable alternative to traditional wire solutions.	Share in the marketing and communication costs	Medium	Opex
	Develop mass market managed EV charging service	Develop a managed EV charging flexibility services that can be offered to the mass market.	Cost of developing the service	Medium	Capex
Function - Flexibility management	Cost reflective price signals for network operators	To reflect the value of flexibility services to sellers.	Development of prices for flexibility services	Small	Opex
	Wire vs non-wire feasibility model	To develop the tools to assess the viability of non-wire solutions as an alternative to traditional wire solutions	Develop the processes and systems to incorporate the assessment into asset management practices	Medium	Capex

Action layer	EV Connect Roadmap Actions	Action purpose	What the funding is needed for	Materiality ($ value)	Type of funding
	Procurement of managed EV charging services	Networks are actively procuring EV demand management services as a demand management tool.	Allowance to purchase flexibility services	Large	Opex
	Implement LV monitoring and demand and constraint forecast tools	Implement the LV monitoring investment recommended in the business case.	Purchase and install LV monitoring equipment and potentially purchase external data sources to complement direct monitoring	Large	Ooex & Capex
	Develop & implement ability to integrate services into demand management response	incorporate flexibility services into demand management response	Trial and develop capability	Large	Innovation funding leading to capex
	Develop & implement dynamic flexibility requirement	Refine the precision of network congestion forecasts, incorporating real time data that will allow networks to immediately see the impact that flexibility services are having on network performance. This will improve the accuracy of flexibility price signals.	Trial and develop capability	Medium	Innovation funding leading to capex
	Develop & implement ability to integrate multiple services into demand management response	Refine and improve an EDBs ability to incorporate a wider range of flexibility services. This could include services that improve power quality and services with two-way power flows that offset peak demand.	Trial and develop capability	Medium	Innovation funding leading to capex
Commercial - Standard terms & conditions	Guidance for flexibility operating agreements	To provide template and guidance on developing the operating terms for flexibility services.	To develop agreements	Small	Opex
	Develop template flexibility tender documents	To provide template and guidance on developing the operating terms for flexibility services.	To develop templates	Small	Opex
	Develop market participation terms and commercial model	Develop terms and conditions for participating in purchasing or selling flexibility services in a centralised market	Develop commercial framework for a centralised model	Medium	Innovation funding/Opex
	Data storage, processing and analysis function	Collecting and processing consumption data to be used in demand forecasting, network planning and demand management.	Funding to either provide this function in house or to purchase it as a service.	Medium	Opex or Capex

Action layer	EV Connect Roadmap Actions	Action purpose	What the funding is needed for	Materiality ($ value)	Type of funding
Information - Planning and response	Purchasing consumption data	Purchasing consumption data – most likely from meter provider	Purchasing consumption data – most likely from meter provider	Medium	Opex
Information - Signalling requirements	Static future congestion heatmaps	To indicate to flexibility providers where flexibility services will be needed on a distribution network.	Develop capability	Small	Opex
	Dynamic network congestion heat maps	Refine the work heatmaps to provide a more precise measure of network congestion.	Develop capability	Small	Opex
	Dynamic flexibility requirement signals – timing and scope dependent on outcomes of centralised marketplace and DSO feasibility study	Refine the price signal for flexibility services to reflect the more precise measures of network congestion.	Develop capability	Small	Opex
Communication standards	Common DER communication protocols	Standard communication protocols to ensure that DERs can communicate with flexibility participants.	Trial and develop capability	Medium	Innovation Allowance
	Develop protocols for flexibility operating instructions	Standard communication protocols for communicating operating instructions to flexibility providers and participating DERs to act on.	Trial and develop capability	Small	Innovation Allowance
	Develop flexibility market protocols	Standard communication protocols for buyers and sellers participating in the flexibility service market.	Trial and develop capability	Small	Innovation Allowance

WELL is also a participant in the FlexForum which is an industry working group that is collaborating on the deliver of many of the actions identified in the EV Connect Roadmap. A key barrier identified by the start-up flexibility provider participants in the working group, is the difficulty funding the development of the technology and services to directly manage customer devises. EDBs will be one of the principal buyers of flexibility services and they currently do not have the allowances or incentives to fund trials and to assist flexibility providers to develop their products and services. If EDBs and other industry participants do not support flexibility providers financially to develop the services to the scale needed to provide a meaningful alterative to wire solutions, the services will not be ready to use when they are needed.

5.3. Case study 4: Forecast network investment – a sustained increase in investment, over multiple regulatory periods

In 2021 we started development of a long term (30 year) network demand forecast model which models the impact of New Zealand's ERP and population growth on the Wellington Network. Please note, our demand and investment models are being continuously developed and refined and often use high level assumptions that have not had a high degree of verification. The modelling results are provided for illustrative purposes only.

The demand forecast has been refined to include the updated ERP. Demand is forecast to increase by 108% over the next 30 years. Figure 9 summarises the main drivers and the current assumptions used.

While the forecasts for EV and population driven peak demand growth can be made with a high level of confidence, the demand forecasts for electricity as a gas substitute and the demand offset from flexibility services are less certain. Our forecast assumes electricity will replace fossil gas, but the ERP includes the possibility of gas use being replaced with a renewable gas source. We have forecast flexibility services to offset some peak demand, but they have yet to be developed to the scale needed.

We expect much of the future demand increase to come from existing connections and not from new customers. Growth from EVs and the transition from gas will be delivered from the existing network. This has implications for the types of regulatory mechanisms used to provide specific allowances. The large new connection re-opener for example, would not be in the right form to fund this type of demand growth.

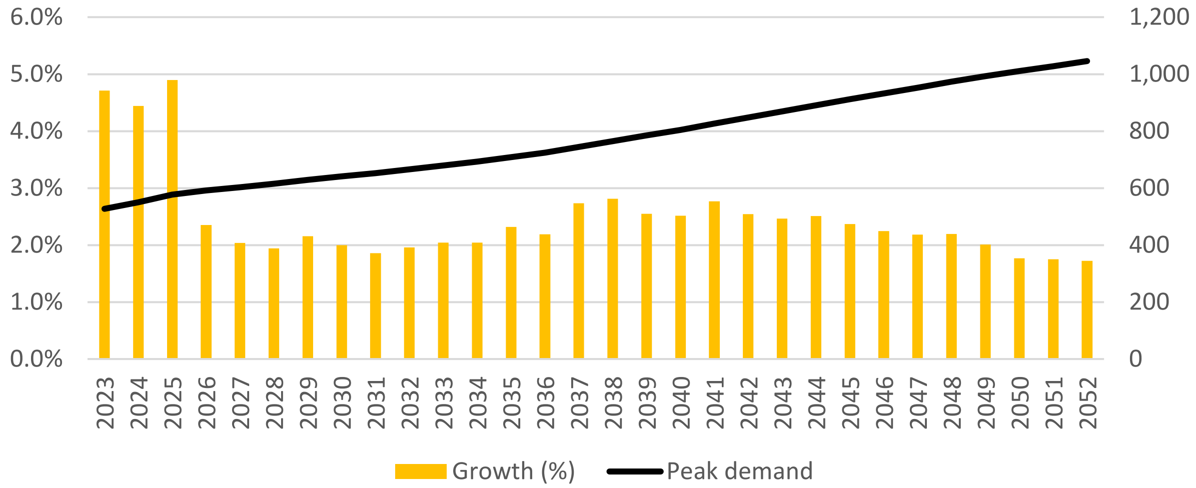
Figure 9: Growth assumptions and rates

Growth		Assumption	Peak demand MW	Total change (%)	Annual change (%)
Current demand (2022)			504	n/a	n/a
Growth	Population growth	Population growth + housing shortage	154	31%	1.02%
	Transport electrification	Climate change programme	251	50%	1.66%
	Transition from gas	Climate change programme	260	52%	1.72%
New growth			665	n/a	n/a
Total new growth (2052) - uncontrolled			**1,168**	**132%**	**4.4%**
Load control		Introduction of flexibility services	-123	-24%	-0.81%
Total new growth (2052) - controlled			**1,046**	**108%**	**3.59%**

Figure 10 provides our forecast peak demand profile on the Wellington network. We forecast peak demand to increase from 503.5MW (2022) to 1,046MW (2052), a 108% increase. Growth is highest to begin with (between 4-5% p.a.) due to high probability, large electrification projects[8], before settling back to a long-term average growth of 2.5%.

Figure 10: Peak demand growth and growth rate forecast

[8] This includes the electrification of public transport and the conversion of coal boilers to electricity.



Under the current regulatory model, networks are incentivised to operate with minimal capacity headroom to keep prices low - the step change in demand means that large proportions of the high value, high voltage backbone will quickly run out of capacity and will need early reinforcement. An investment step change is also needed for the replacement of two of WELL's largest asset fleets – specifically the underground cable and power transformer fleets.

Figure 11: provides the forecast capital investment profile - $2.0b over the next 30 years. Under the past business-as-usual operating environment, focused on providing a steady and reliable supply of electricity, capital expenditure has been an average of $32m p.a. since the purchase of the network in 2009. This is expected to increase to $72m p.a. (real) for the next 30 years.

Note, the capex forecast has not been programmed and does not consider resourcing or other delivery constraints. Programming the delivery of the capex would smooth the expenditure.

Figure 11: forecast capex

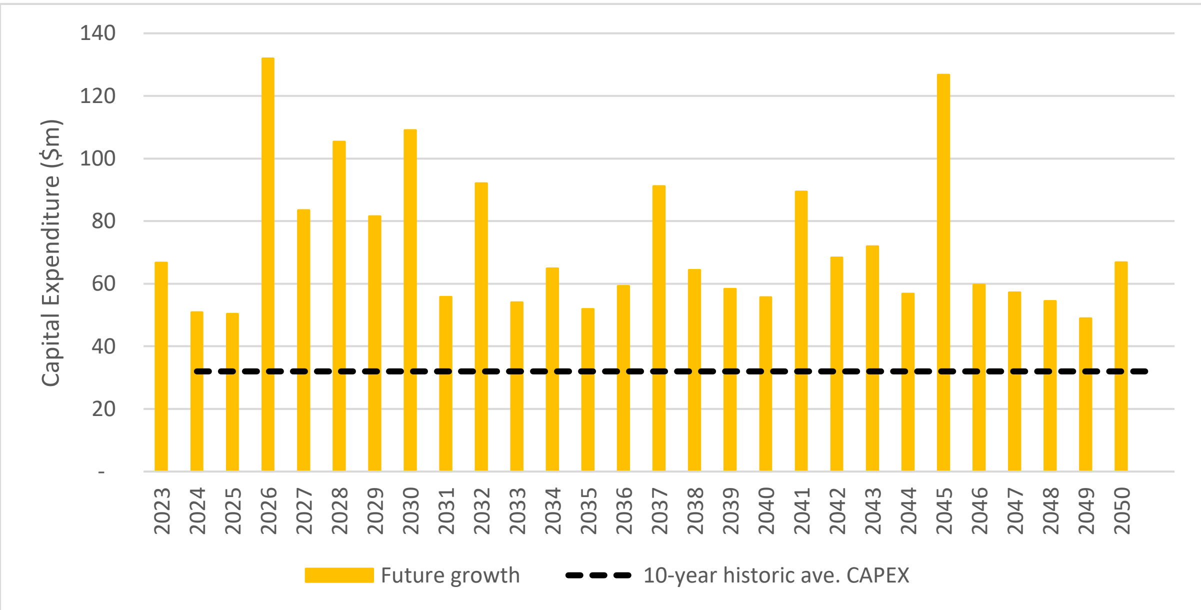
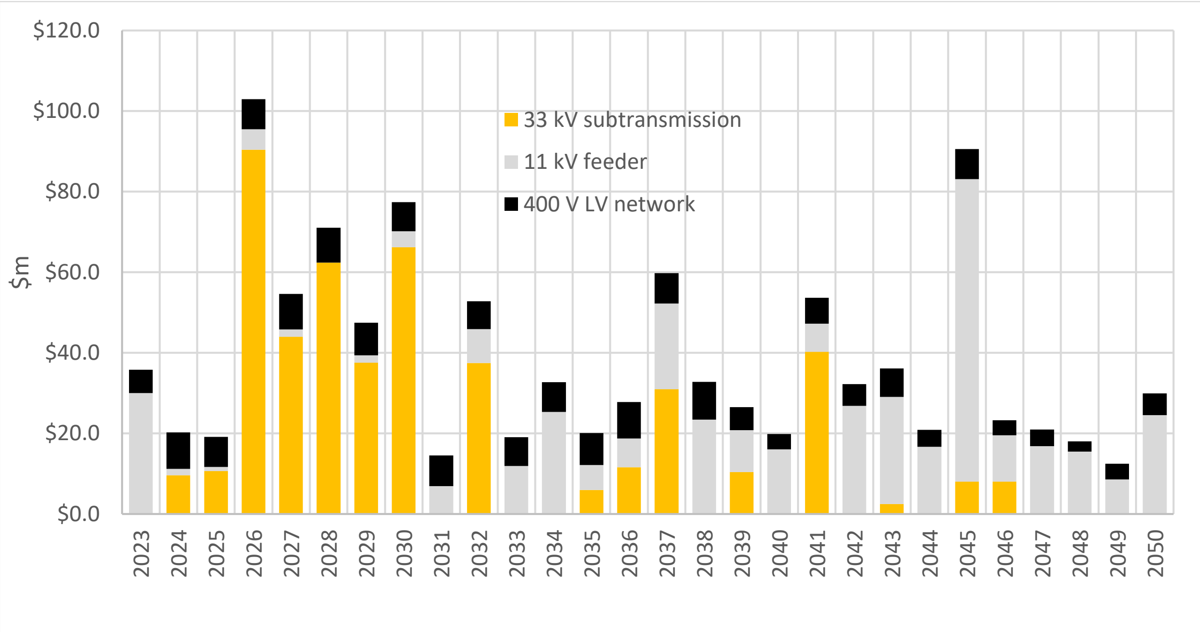


Figure 12 provides a breakdown of when each different network needs reinforcing with new capacity. The 33kV sub transmission and the low voltage networks will run out of capacity early and will be the initial focus of the investment programme. The 11kV networks will be upgraded with additional capacity over the 30-year investment time frame.

Currently we do not have visibility of the LV network and our LV capacity modelling is based on a high-level assumption. The resulting capex is only indicative and requires verification. Until we have better visibility of the LV network, we will not be able to accurately forecast LV capex.

Figure 12: – network reinforcement forecast



Changing characteristics of the investment forecast include:

1. **Material step change, significantly larger than historic average:** We are forecasting a 108% increase in demand by 2052 on the Wellington network. The network does not have the spare capacity to meet the demand increase and new capacity will need to be built. The investment increases from an average of $32m p.a. to $72m p.a. – a material step change from business-as-usual investment.
2. **Sustained across multiple regulatory periods:** Like other EDBs, WELLs investment programme will be required to deliver new capacity and continue to replace aging assets to maintain network reliability, security and power quality. Unlike past step changes in investment that could be ring fenced into a single regulatory period (Powerco's, WELL's and Orion's CPP programmes), the size and timing of future ERP related investment will require a sustained increase in investment across multiple regulatory periods.
3. **Front loaded:** The investment is front loaded with the highest investment being in the first 10 years. This is because the high voltage network (particularly the 33kV sub-transmission network) does not have the capacity headroom to deliver the rapid early growth.
4. **Significant LV network reinforcement:** Investment in the LV network will also be needed. Investment in LV visibility will be needed immediately to enable the network planning team to assess whether customers can safely and securely connect customer DER.
5. **Growth will also come from existing connections:** Much of the demand growth will come from EVs and (potentially) transitioning from fossil gas to electricity and will be delivered from existing connections.
6. **Majority of expenditure will be from reinforcement of the existing network:** 53% of WELLs forecast investment is expected to come from reinforcement of the existing network, replacing existing assets

with assets with more capacity. Brownfield network reinforcement is more expensive than greenfield because of the complexity of working within existing infrastructure.

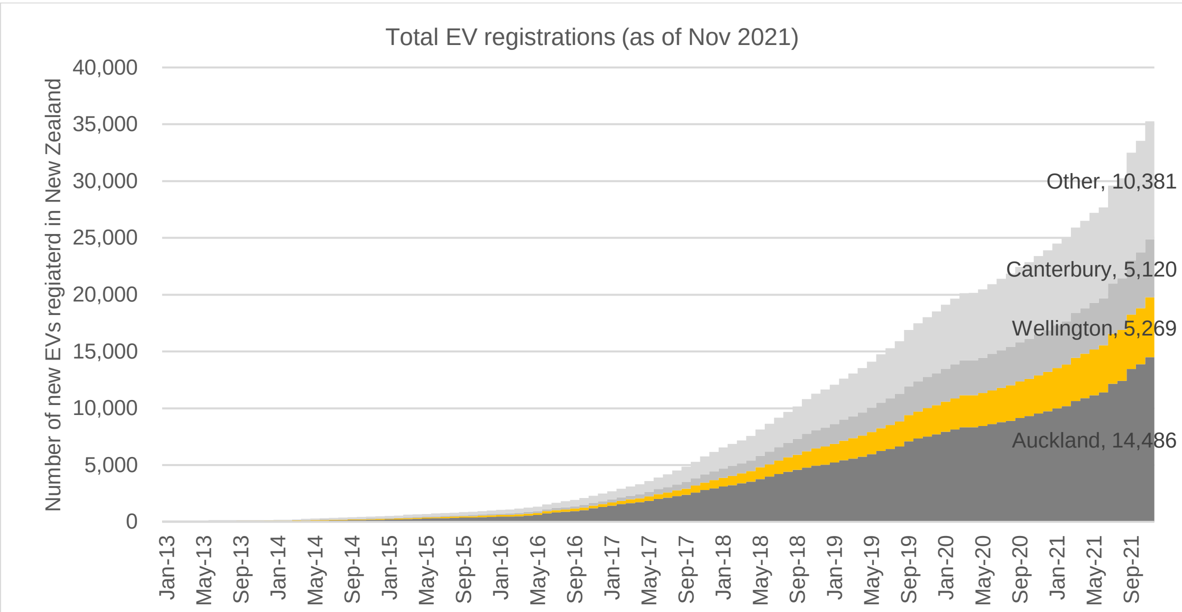
7. **Opportunity for flexibility services to value stack within the network:** Significant value can be provided by flexibility services if shifting peak demand helps defer network reinforcement at the 33 kV, 11 kV and low voltage networks. Networks will need to develop network planning and demand management tools to identify where flexibility service will provide the most value.

5.4. Case study 5: Investment uncertainty

While we can be confident that EDBs will have to build new capacity and some of that new capacity will be needed very soon, there is still uncertainty around the size of the demand increase and when new capacity will be needed. Specific drivers of demand uncertainty include:

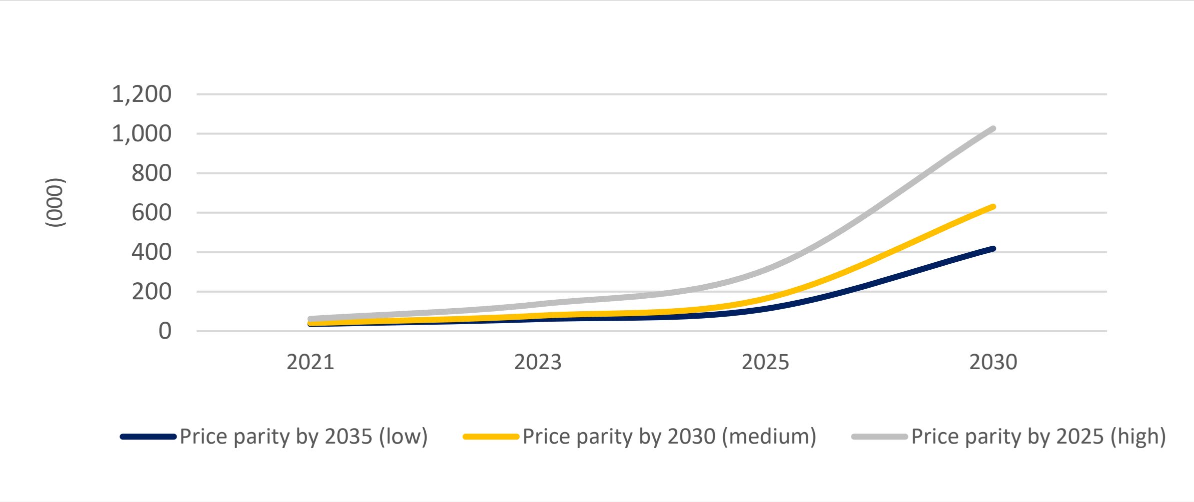
1. What the substitute for fossil gas will be? Whether the electricity system will be expected to provide some or all of the energy use currently provided by natural gas. As highlighted in the Figure 9, this equates to approximately half of the forecast demand increase.
2. Whether flexibility services will be developed to the scale needed to better utilise the existing distribution network and avoid 22% of the future demand increase (provided in Figure 9)? Without flexibility services, we would have to build new capacity to deliver a 132% increase in demand.
3. What the speed of EV uptake will be? i.e. when will the capacity be needed to deliver the 48% increase in demand (from Figure 9).
4. Figure 13 shows that in the last year the Wellington network has seen the EV growth rate double in line with the governments subsidies. In November 2020 there were 3,400 EVs in Wellington and a year later In November 2021 there were 5,300 EVs. EV growth over the last year has added a 0.5% increase in electricity consumption alone.
5. When will each of the 4,500 LV networks require upgrading? Networks currently have no visibility of demand on each of the LV networks and where customers are adding DER like EVs. While distribution connection standards say that customers must apply to an EDB before connecting, there is no requirement for a customer to tell a network they are connecting a large DER that does not pass electricity back to the network.

Figure 13: EV registrations

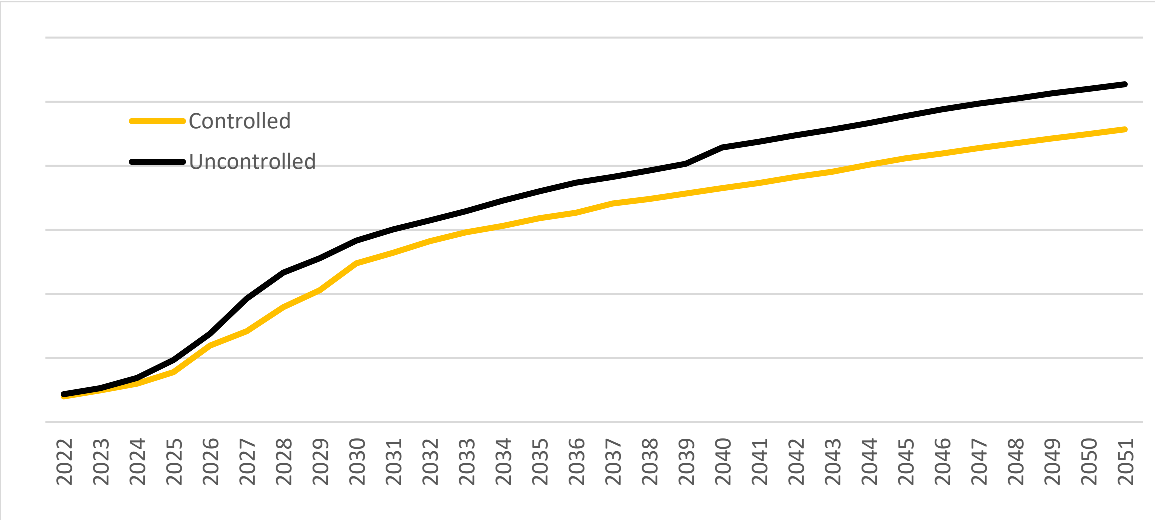


EV uptake rates have been shown to be dependent on a range of drivers like the level of government subsidies and the affordability of those devices and suppliers' ability to keep up with demand for those devices. The electric vehicle growth scenarios shown in Figure 14 vary based on how fast the price of EVs reach price parity with internal combustion engine (ICE) vehicles. The speed at which this occurs will be influenced by factors like production/technology costs, government subsidies and incentives.[9]

Figure 14: Forecast EV uptake (New Zealand, national estimate)



Forecast demand drives when new network capacity is needed. Fast demand growth means that EDBs will have to invest sooner to meet that demand. Lower demand means networks can delay when they need to build new capacity and can delay higher prices needed to fund that investment. To illustrate the impact of uncertainty on the investment programme, we have compared the cumulative investments for controlled and uncontrolled investment scenarios. We are still developing our investment scenario analysis and we expect other scenarios (like those excluding gas demand growth) to have a larger impact on investment.



EDBs must carefully judge when new capacity is needed – either by building a larger network or by or 'freeing' capacity by better utilising the existing network. If new the capacity is provided too late, then the network will not be able to deliver customer demand when its needed. An EDB would then not be meeting its quality expectations and will be exposed to regulatory penalties and potentially regulatory fines up to $5m. Conversely, an EDB could build early to reduce the risk that the network does not meet customer demand and that it cannot maintain its reliability targets. However, this more conservative approach could lead to customers paying more

[9] Energy Efficiency and Conservation Authority by KPMG, https://www.eeca.govt.nz/assets/EECA-Resources/Research-papers-guides/EV-Charging-NZ.pdf

unnecessarily. The value to customers of building early could be significant – Figure 7 from Case Study 2 provides the annual value of deferring network reinforcement for 400v, 11kV and 33kV networks. These values also reflect how much more customers would pay if an asset if reinforcement earlier than is needed.

EDBs will also need to judge what capacity the new investment will need - network reinforcement investments will need to be able to deliver the demand growth over the life of the asset. If the EDB underinvests, they could create a stranded assets if the asset has to be replaced early with more capacity. Customers will continue to fund the existing asset at the same time as the new asset. Alternatively, if more capacity than is needed is built initially, customers will pay more than is needed (the asset will have been gold plated).

The judgement of when new capacity is needed and what capacity is needed will become more difficult – EDBs will not be able to precisely match demand and capacity like they have in the past. Some of the drivers of demand change could result in rapid changes that may require networks to quickly change their investment forecasts. For examples, exponential EV growth could quickly add unexpected new load within a regulatory period. Other changes, like confirmation whether a renewable gas alternative to fossil gas to be viable, will be slower and the ability to change investment profiles within a regulatory period may not be as important.

An EDB may also have to flex when to build to match the availability of resources. As illustrated in Case Study 4, we are forecasting average capex expenditure to be 2-3 times current expenditure over the next 30 years and up to 4-5 times for the first 10 years. If other networks are also investing in their networks at the same rate, there is likely to be a resource shortage. Not only will networks need the ability to adjust their investments to match demand, but they will also need to consider the availability of resources as part of these investment forecasting.

The current regulatory model provides allowances in five-year investment blocks, assuming well understood demand increases. This approach may create cost inefficiencies as EDBs consider building early to reduce the risk of demand exceeding capacity and incurring regulatory penalties and fines.

Changing characteristics of the investment forecast include:

1. **Uncertain investment timing**: While EDBs can be confident that a significant increase in invest will be needed, the timing and the size of the investment could be uncertain. Slower or faster than expected demand will impact when the investment is needed and the capacity of the new assets.
2. **Quickly changing demand**: Some of the underlying drivers of changing demand could change demand quickly with little lead in time for networks to adjust their investment forecasts and allowances calculations. Significant changes in investment requirements (both increases and decreases) could occur within a regulatory period. Networks may have to adapt their investment profiles within a regulatory period for demand uncertainty relating to the uptake of customer devices (like EVs) that can increase demand quickly.
3. **Uncertain resource availability:** The availability of resources may also impact the timing of an investment. EDBs may need the ability to shift when they can build, new assets to when resources are available.
4. **High value in being able to closely match capacity and demand:** The avoided cost of building to early or building too late are high. There is value in EDBs being able to flex their investment programmes to match changes in demand.
5. **EDBs will have to invest in new tools and capability:** New tools and capability are needed to allow EDBs to closely match demand with capacity. EDBs will need to visibility of their LV networks, demand forecasting tools and the ability to call on and incorporate flexibility services.