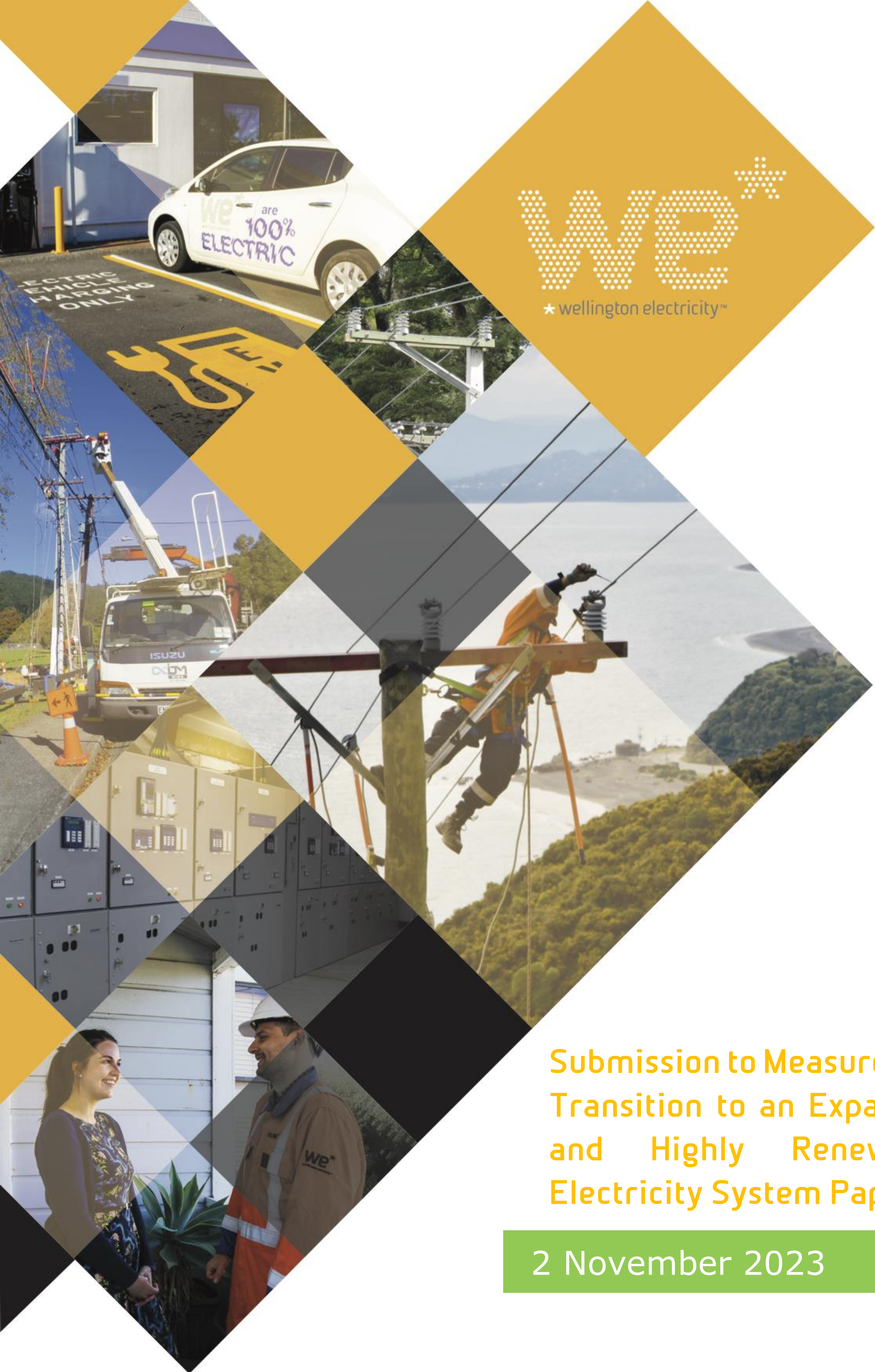

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Submission to Measures for Transition to an Expanded and Highly Renewable Electricity System Paper

2 November 2023

Submission and contact details

Consultation	Measures for a Transition to an Expanded and Highly Renewable Electricity System Paper 2023
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Release of information

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

1 Introduction

Wellington Electricity (WELL) appreciate the opportunity to submit feedback on the Measures for Transition to an Expanded and Highly Renewable Electricity System Paper ('the paper') that aims to highlight and investigate the focus for the electricity sector in the coming decades as the country decarbonises and new technologies change the way we think about the electricity supply chain.

WELL is a distribution network that manages the local lines that deliver power to Wellington, the Hutt Valley, and Porirua. We power around 173,000 homes and businesses and are anticipating a greater than 100% increase in demand on our network over the coming decades due to a large electrification plan through the government's net-zero targets.

It will be necessary for the whole energy sector to ramp up the scale of expansion across generation, transmission, and distribution in a coordinated way that factors in resource constraints, new technologies, and market incentives. It is also critical that the sector can 'keep the lights' on during this period of transition while maintaining equitable outcomes for customers.

As a regulated entity, WELL is subject to price/quality control through the Commerce Commission and the Electricity Authority. The current price path determination is based on historical trends and is not fit for the anticipated growth of electrification. A backward-looking model has its own challenges in being able to anticipate where investment in the network is required and where alternate solutions may be appropriate. Not all growth will require traditional pole and wire construction, and there are opportunities to establish efficient solutions where the end customers interact with the market through flexibility services. This highlights how the setup of the market is changing, with the risks and dependencies shifting from large assets of generation and transmission, to behind the meter at customers' homes or businesses. New Zealand’s commitment to reducing carbon emissions needs to ensure the reliability and resilience of its energy infrastructure is bolstered as electricity becomes more decentralised through growth in electrification of transport, and distributed energy resources (DERs).

The industry is already banding together to come up with foundational concepts that outline the framework needed to collaborate the multitude of participants and their differing incentives. Specific distribution-oriented initiatives are highlighted in this paper such as The Flex Forum, ENA’s Future Networks forum and EEA’s Flex-Talk. There is a need for the government to collaborate with these working groups to deliver the legislation, policy and regulation that enables innovation and delivers the best outcomes for NZ Inc.

2 Part 1: Growing Renewable Generation

2.1 Are any extra measures needed to support new renewable generation during the transition?

Please keep in mind existing investment incentives through the energy-only market and the ETS, and also available risk management products. Any new measures should add to (and not undermine or distort) investment that could occur without the measures.

No comment.

2.2 If you think extra measures are needed to support renewable generation, which ones should the government prioritise developing, and where and when should they be used? What are the issues and risks that should be considered in relation to such measures?

No comment.

2.3 If you don't think further measures are needed now to support new renewable generation, are there any situations which might change your mind? When and why might this be?

No comment.

2.4 Do you think measures could be needed to support new firming/dispatchable capacity (resources reliably available when called on to generate)? If yes, which kind of measures? What needs do you think those measures could meet and why?

No comment.

2.5 Are any measures needed to support storage (such as battery energy storage systems or BESS) during the transition? If yes, what types of measures do you think should be considered and why?

No comment.

2.6 If you answered yes to question 4 or 5 above, should the support be limited to renewable generation and renewable storage technologies only or made available across a range of other technologies?

Keep in mind that fossil fuels are generally the cheapest option for firming, though this may change over time as renewable options (particularly batteries) become more efficient and affordable.

No comment.

2.7 If you answered yes to question 6 above, what are the issues and risks with this approach? How could these risks and issues be addressed?

No comment.

2.8 Are any measure(s) needed to support existing or new fossil gas fired peaking generation, so as to help keep consumer prices affordable and support new renewable investment?

No comment.

2.9 If you answered yes to question 8 above, what measures should be considered and why? What are the possible risks and issues with these measures?

No comment.

2.10 If you answered yes to question 8 above, what rules would be needed so that fossil gas generation remains in the electricity market only as long as needed for the transition, as part of phase down of fossil gas?

No comment.

2.11 Are there any issues or potential issues relating to gas supply availability during electricity system transition that you would like to comment on?

No comment.

2.12 Do you agree that specific measures could be needed to support the managed phasedown of existing fossil fuel plants, for security of supply during the transition?

No comment.

2.13 If you answered yes to question 12 above, what measures do you think could be appropriate and why? What conditions do think you should be placed on plant operation?

For example, do you have any views on whether there should be a minimum notice period for reductions in plant capacity, and/or for placing older fossil fuel plant in a strategic reserve?

No comment.

2.14 If you answered yes to question 12 above, what are the issues and risks with these measures and how do you think these could be addressed?

No comment.

2.15 What types of commercial arrangements for demand response are you aware of that are working well to support industrial demand response?

No comment.

2.16 What new measures could be developed to encourage large industrial users, distributors, and/or retailers to support large-scale flexibility?

As discussed in Part 4 of this paper. A coordinated platform for trading flexibility services would allow distributors to manage the quality and integrity of the networks they operate and enable those participating in flexibility services to be compensated. It is essential that regulatory measures are established in a coordinated way to enable innovation in this area. Through an agreed needs and principles basis, market participants benefit through flexibility and coordination across the supply chain.

2.17 Do you have any views on additional mechanisms that could be developed to provide more information and certainty to industry participants?

No comment.

3 Part 2: Competitive Markets

3.18 Do you agree that the key competition issue in the electricity market is the prospect of increased market concentration in flexible generation, as the role of fossil fuel generation reduces over time?

No comment.

3.19 Aside from increased market concentration of flexible generation, what other competition issues should be considered and why?

No comment.

3.20 What extra measures should or could be used to know whether the wholesale electricity market reflects workable competition, and if necessary, to identify solutions?

No comment.

3.21 Should structural changes be looked at now to address competition issues, in case they are needed with urgency if conduct measures prove inadequate?

No comment.

3.22 Is there a case for either vertical separation measures (generation from retail) or horizontal market separation measures (amending the geographic footprint of any gentailer) and, if so, what is this?

No comment.

3.23 Are measures needed to improve liquidity in contract markets and/or to limit generator market power being used in retail markets? If yes, what measures do you have in mind, and what would be the costs and benefits?

No comment.

3.24 Should an access pricing regime be looked at more closely to improve retail competition (beyond the flexibility access code proposed by the Market Development Advisory Group or MDAG)?

No comment.

3.25 What extra measures around electricity market competition, if any, do you think the government should explore or develop?

No comment.

3.26 Do you think a single buyer model for the wholesale electricity market should be looked at further? If so, why? If not, why not?

No comment.

4 Part 3: Networks for the Future

4.27 Do you consider that the balance of risks between investing too late and too early in electricity transmission may have changed, compared to historically? If so, why?

New Zealand's Emissions Reduction Plan is dependent on electrification with the electricity sector delivering nearly 50% of the 2050 net emissions target. The pace of electrification will be dependent on transmission and distribution networks having the new capacity available to meet the increase in decarbonisation-related demand.

New Zealand has had a steady historical demand growth so there was always a risk that demand would not eventuate if the investment was too early. Historically, investing too late meant reduced security and reliability of the system as the main risks. The balance has significantly changed because the additional risks of investing too late now include:

- The cost of not meeting the emissions reduction targets associated with electrification.
- The cost of new renewable generation that has been built but cannot be delivered to customers and remains idle.

- The household energy bill savings from electrifying vehicles that New Zealand families will not receive because the new electricity supply needed to charge their vehicles is not available.

Comparatively, the cost of building early could be immaterial when compared to the cost of building late. Building early has the additional benefits of avoiding assets being stranded and the full utilisation of the asset life optimised.

4.28 Are there any additional actions needed to ensure enough focus and investment on maintaining a resilient national grid?

The overall resilience assessment framework appears robust and recognises the increasing importance of resilience as electricity becomes New Zealand's primary energy source. Resilience applies equally to distribution networks as to the national grid.

An important risk to resilience and energy security moving forward will be Transpower's ability to keep pace with demand and generation increases. Not only must the transmission network be resilient to natural disasters, but the networks must also have the capacity to meet increasing demand peaks. An important resilience mitigation will be building new capacity before it is needed.

Transmission network resilience plans must be coordinated with distribution network resilience and investment plans so that the transmission grid provides electricity. For example, relocating GXPs from flood-prone areas will also require distribution assets to be relocated. Distribution networks will also have to apply to the Commerce Commission for funding and the timing of that funding will need to be coordinated with Transpower's investment path so that the works can be completed at the same time. An example on the Wellington network where resilience plans have not been coordinated and the security of supply has been affected is the Central Park GXP single point of failure. In 2016 CPK was identified as a critical risk by the Wellington Lifelines Group earthquake risk assessment, but this is still to be resolved. There are 12 GXPs identified in 2023 by Transpower as needing additional resilience measures due to the risk of flooding and the investigations began happening from July 2023. New Zealand cannot have a larger dependency on electricity while there are so many types of resilience risks are left unattended for 7+ years.

4.29 Do you agree we have identified the biggest issues with existing regulation of electricity distribution networks?

We agree that two of the areas identified are significant issues:

1) Network investment model – the current regulatory system is designed for a BAU operating environment that supports steady growth and is focused on the efficient replacement of aging assets.

We agree that the regulatory model now needs updating to support the changing high-growth environment. This is a primary driver that underpins most of the other issues identified.

2) Pricing signals to provide efficient use of networks – distribution price signals are recognised as a current issue; however, it is important to note that networks are currently working to remove low fixed user tariffs and are in the second of five year removal process. Distributors cannot fully move to cost-reflective pricing until low fixed tariffs are removed. Cost-reflective pricing of using electricity during peak demand periods will incentivise flexibility services and customers to shift demand away from network peaks.

Of the other issues identified (removing barriers and cost allocation), both are interrelated with the network investment model not being fit for purpose. We agree that existing distribution network resourcing creates a barrier to customers connecting because the current regulatory model does not incentivise building new capacity before it is needed, and this has led to inconsistent distribution business policies. Large industrial decarbonisation and transport electrification often require a step change in capacity and wider reinforcement of the network backbone that distribution businesses must apply to the Commerce Commission for more allowances.

We do not agree that network upgrades and anticipatory capacity cost allocated to the initial connecting customer is a connection barrier for all networks. The Electricity Authority's Targeted Reform of Distribution Pricing - Issues Paper highlighted this issue and that most networks fund the cost of future network growth from their tariff revenue and not the upfront connection cost. This will be an important focus for the next price path reset.

4.30 Are there pressing issues related to the electricity distribution system where you think new measures should be looked at, aside from those highlighted in this document? How would you prioritise resolving these issues to best enable the energy transition?

Nothing additional to add that is not already mentioned in this document.

4.31 Are the issues raised by electricity distributors in terms of how they are regulated real barriers to efficient network investment?

Please give reasons for your answer. Is there enough scope to address these issues with the current ways distributors are regulated? If not, what steps would you suggest to address these issues?

The bullets highlighting the regulatory barriers are a subset of a larger, more comprehensive list of issues identified as part of the Commerce Commission's Input Methodology consultation by a wide range of stakeholders, not just distribution networks as stated in this consultation.

The public Input Methodology consultation provided a forum for all stakeholders to participate in identifying and debating the regulatory issues and what changes might be required.

The issues identified are some of the barriers to efficient network investment and we refer to the full Input Methodology consultation and submissions for the complete set which also includes important issues like:

- The lack of innovation funding which networks need to develop the capacity to incorporate flexibility services into their asset management practices.
- The impact of regulatory mechanisms on cashflows and the ability of a network to fund the step change in investment required while providing a fair return for that investment.
- Concerns around the cost of capital calculation and the impact it will have on the ability of a network to attract the additional investment needed to fund the $22b investment programme.

The Commerce Commission has enough scope to address most of the issues identified in the Issues discovery phase of the Input Methodology consultation.

The exception is the Price Paths available to the Commerce Commission under Part 4 of the Consumer Act. As highlighted in our submission to the Draft decisions on the IM Review 2023, an Individual Price Path (IPP) would provide a better framework for networks that need to make large and sustained levels of investment. Currently, networks need to make a Customised Price Path (CPP) application which has been designed for discrete one-off, three-to-five-year investment programmes. Submitting a CPP application can incur costs between $5m - $7m for a one-off funding request. Rather than continue to submit multiple CPP applications, we think an IPP, like that used for networks in Australia, the UK, and Transpower, would be more appropriate. Using an IPP for networks with large, sustained investment profiles could:

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

This would require a change to the Commerce Act 1986 to allow the Commerce Commission to extend the IPP for Transpower to distribution networks and was recommended (E4) of the Electricity Price

Review. We believe having an IPP option would enable more effective, tailored regulation and allow the flexibility for change required on network investment.

4.32 Are there other regulatory or practical barriers to efficient network investment by electricity distributors that should be thought about for the future?

As highlighted in the 'Boston Consulting Group, The Future is Electric' distribution capacity needs to be built rapidly and much of that build is required before 2030. The next regulatory reset which provides the new allowances starts in 2025, leaving only five years for distribution networks to deliver $22b of network investment identified on the Boston Consulting roadmap.

Networks will need ~$15b in new debt and equity which will mean attracting new investors at the same time as other parts of the energy sector will also be seeking new investors. ~$15b investment would double the capital invested in distribution networks from the $14.5b currently invested.

Most networks are owned by trusts and local authorities that may be restricted in their ability to raise new capital from their existing sources and may need to consider private investment. The focus of the Input Methodology review has been on an efficient regulatory cost, but access to new capital should also be considered:

1) The Commerce Commission will need to carefully balance ensuring networks do not earn excessive profits with a regulatory return that can compete with other investment opportunities.

2) While the Overseas Investment Act has been reviewed, there are still barriers and additional considerations for investments in critical infrastructure.

3) Networks short of capital will need to consider what other funds are available to invest in their networks.

4.33 What are your views on the connection costs electricity distributors charge for accessing their networks? Are connection costs unnecessarily high and not reflective of underlying costs, or not? If they are, why do you think this is occurring?

The Customer Contribution Policy outlines the connection cost allocation for new customers or customers altering their existing services on the Wellington network. Connection costs are funded by a combination of tariff, and upfront customer capital contribution. These costs are for assets that only the new customer, or the customer altering their existing connection, benefit from and include the capital cost of designing and installing the new connection assets or any new assets needed to adjust an existing service.

Upstream network reinforcement will be included in the customer capital contribution calculation if there is a primary benefit to the connecting customer. This ensures that the connecting customers are paying for the costs they are driving. Reinforcement costs will be funded from tariffs only if the upstream network reinforcement benefits other existing or future customers. This is the case for most network reinforcement investments on the Wellington network. It is rare for reinforcement costs to only be of benefit to the customers connecting. If the loads being added to the network can be managed so they are dynamic, this gives networks relief capacity for reinforcement.

The customer capital contribution shows a balance between affordability and customer funding, that best reflects the costs they drive. Affordable connection costs will encourage more customers to connect, lowering overall prices by spreading the costs over more customers. We reflect this balance by the connecting customer paying historically 60-70% of the cost to connect and the remainder funded by tariff revenue over time.

We believe this is the most equitable representation of the true connection costs and is essential that the application of the Customer Contribution Policy be consistent over time so that similar customers pay a comparable upfront cost and intergenerational cross-subsidisation is limited. For example, if a customer pays more upfront and then pays the same standard network tariff as an existing customer whose upfront cost is less, then they will be subsidising the latter.

As highlighted by the Electricity Authority in their recent 'Targeted reform of distribution pricing', this is the general approach taken by most networks. A minority of networks also include wider network reinforcement costs that benefit other customers in their customer capital contribution calculation.

Connection costs are reflective of an efficient cost to connect

We disagree that connection costs are not reflective of the underlying cost to connect for most networks. WELL operates an outsourced delivery model and tenders large new connections to reflect market prices. Traffic management costs are included and make up a large proportion of the connection costs. Capital contributions reflect the actual, market-based cost to connect as the regulatory model does not allow a margin to be applied to connection works.

Capital contributions reflect the resources and equipment necessary to connect customers and ensure existing customers are not subsidising new connections. The cost to connect is not trivial and often encompasses; expensive transformer or switch gear equipment; civil works for underground installs; and work in a busy and complex urban environment that requires coordination and careful planning.

We do think there are always opportunities to streamline the connection process and find ways of reducing costs further. We support ENAs work programme with Drive Electric to investigate improvement areas.

4.34 If you think there are issues with the cost of connecting to distribution networks, how can government deliver solutions to these issues?

The constraint driving the cost of connecting to distribution networks is bound by the limited network capacity available at peak periods. Distributors will need to reinforce the backbone of their networks that applies across all periods to ensure their networks can handle the extra volume of new demand. The government should focus on the development of dynamic flexibility services as they remove the complete need and cost to increase the capacity of the whole network. Dynamic services can still operate during less congested periods and can protect the network by maintaining a secure supply in peak periods. It is likely that dynamic services will be a cost-effective option and reduce the infrastructure costs and timescale needed for substantially upgrading assets. Funding for this type of investment needs to be included in the regulatory allowances as there are currently no methods for EDBs to fund this.

4.35 Would applying the pricing principles in Part 6 of the Code to new load connections help with any connection challenges faced by public EV chargers and process heat customers? Are there other approaches that could be better?

EV chargers and process heat customers make up a relatively small proportion of the thousands of new connections each year as provided in distribution networks annual pricing disclosure. It is not necessary to apply the pricing principles in Part 6 of the Code because a unique connection process would add unnecessary costs and complexity. Part 6 pricing principles were implemented for safety reasons to ensure that the two-way power flows created by PV connections can be safely managed, not to help with connection challenges like those faced by EV chargers and process heat customers.

Most of the Part 6 connection characteristics noted in the consultation documents are already provided in our standard online connection request process:

- Networks have connection standards and can provide these on request.
- The connection application form, time frames, and approvals are provided in the online form.

- The pricing principles, capital contribution calculation methodology, and ongoing tariffs are provided in a network's capital contribution policy and in their Pricing Methodology. These are mandatory disclosures.

We do support streamlining and standardising the connection process in general because network characteristics are not identical across EDBs and some level of customisation is required.

4.36 Are there any challenges with connecting distributed generation (rather than load customers) to distribution networks?

We provided feedback to the Electricity Authority on the distributed generation (DG) connection process as part of their 2023 'Updating regulatory settings for distribution networks' consultation. Further implications of DG, like those experienced in South Australia, on managing quality of supply and voltage limits are highlighted in our answers to Part 4 of this paper.

We agreed with the recommendation to review Part 6, the most important issues to review being:

1) Review of application requirements/process for large DGs to provide a clear and better definition of the DG requirements and criteria.

2) Inclusion of DER – the Code needs to be expanded to include a separate set of rules for connecting DERs as they operate differently from DG. DERs are not visible to EDBs, and this is vital for connecting securely.

3) Inclusion of flexibility providers – this is so that DERs do not discourage the uptake of flexibility services.

4) Review of the prescribed maximum fee limits as the existing values do not reflect assessment costs.

4.37 Are there different cost allocation models addressing first mover disadvantage (when connecting to distribution networks) which the Electricity Authority should explore, potentially in conjunction with the Commerce Commission?

As outlined in our response to question 33, most networks have already addressed the first mover disadvantage, and this is not an issue that affects all networks.

Most of the future growth on the Wellington network will come from existing connections (electrification of private transport and the electrification of gas use) and most parts of the network will be constrained and will need new capacity to meet this new demand. Therefore, we fund the reinforcement (network growth) of the wider network from network tariffs and spread the costs over the life of the assets. We use capital contributions to help fund assets that the connecting customer is the primary beneficiary and other customers do not benefit from. This is important so that existing customers are not subsidising connecting customer costs.

However, we also recognise that it is important for the cost to connect to be affordable, so we also fund a small proportion of connection costs (25-30%) using tariffs. We think everybody benefits because it encourages new customers to connect and the wider network operating costs can be spread over more customers, keeping costs lower for everybody.

4.38 Should the Electricity Authority look at more prescriptive regulation of electricity distributors' pricing? What key things would need to be looked at and included in more prescriptive pricing regulation?

As noted above, the Wellington network growth will mainly come from existing connections and therefore the cost and benefit will be attributed across all customers through tariffs. Other networks' future growth could come from new connections and upfront contribution may be the best funding option. This highlights the differing characteristics of the networks and why we do not support prescriptive pricing. EDBs need the ability to adapt their funding policies to ensure existing customers do not subsidise connecting customers where they do not benefit.

Since the publication of this consultation paper, the EA has released its 2023 scorecards on distribution pricing. Almost all EDBs have improved their scorecard since 2021 and this has been reflected through better pricing guidance provided by the Authority.

It is important for EDBs to retain the ability to design their customer capital contribution policies that best suit their own network requirements. We support the current requirement of demonstrating that the customer capital contribution policies align with the pricing principles. The pricing principles provide the test as to whether the policy is efficient and equitable.

We also do not support the government funding network growth. It is the distribution networks' responsibility as the network owner to fund investment in their networks. They can do this by lending from banks or by seeking private investment. Recent infrastructure asset sales show there is strong interest from private investors to invest in network infrastructure. The regulatory model is designed to support both new debt and equity with the cost of capital calculation being based on securing capital at competitive market rates.

4.39 Do current arrangements support enough co-ordination between the Electricity Authority and the Commerce Commission when regulating electricity distributors? If not, what actions do you think should be taken to provide appropriate co-ordination?

Price/quality regulation and regulating the tariff-setting process are distinct processes that can be effectively regulated by different bodies.

Of more importance is coordinating the provision of flexibility services hosted on distribution services. Flexibility services will be sold and used by the wider market which is regulated by the Electricity Authority. The provision of flexibility services could have an impact on network quality performance, which is the Commerce Commission's responsibility. The quality impact of wider market regulation on services hosted by distribution networks will need to be understood so that the impacts are captured in the quality standards and the quality trade-offs are understood by customers.

4.40 Will the existing statutory objectives of the Electricity Authority and Commerce Commission adequately support key objectives for the energy transition?

New Zealand has a legislative mandate to deliver its net carbon zero targets. Supporting regulatory policy should support our legislative obligations. Furthermore, if decarbonisation objectives come into conflict with the existing regulatory objectives, they would prioritise the existing objectives over decarbonisation rather than being able to consider a balanced trade-off.

Regulations for decarbonisation will provide a long-term benefit to consumers by considering extended investment strategies longer than the current 5-year DPP. There is a balancing act between long-term strategies that benefit future customers, and those customers today that fund the investment. The present statutory objectives do not take this into consideration and may result initially in a cheaper alternative but require earlier investment by the next customer than would have been required in the long run. For instance, an EDB could install a transformer that meets current capacity needs but requires upgrading in 10 years to accommodate demand growth from decarbonisation, and therefore the initial transformer is unable to reach the end of the 45-year expected asset life. Installing a larger transformer upfront could save costs in the long run by accommodating future capacity needs.

While the current definition provides both the Electricity Authority and the Commerce Commission the mandate to consider decarbonisation objectives (which they are both doing), it does not require them to do so. The energy sector has always acknowledged the challenge of the energy trilemma and the regulators should consider those challenges equally.

4.41 Should the Electricity Authority and/or the Commerce Commission have explicit objectives relating to emissions reduction targets and plans set out in law? If so,

Should those objectives be required to have equal weight to their existing objectives set in law?

Why and how might those objectives affect the regulators' activities?

As noted in our answer to question 40, the regulators should have explicit objectives and they should have equal weighting with the existing objectives. New Zealand emissions reduction targets are legislated, and the supporting policy should promote its delivery alongside its other legislative obligations already provided for in electricity regulation.

An emissions reduction target objective would help EDBs plan for a longer-term strategy and align with our recommendation to have an IPP option for EDBs. Emissions reduction and the emissions budgets span decades, and how EDBs fund this time needs to be supported by regulators.

WELL also believes that in adding additional statutory objectives, the roles of the Commerce Commission and Electricity Authority could be combined to prevent EDBs being pulled in too many directions by the two regulators.

4.42 Should the Electricity Authority and/or the Commerce Commission have other new objectives set out in law and, if so, which and why?

As New Zealand becomes even more dependent on electricity, customers will be more vulnerable to loss of services from emergency events like storms, earthquakes, and cyber-attacks. The recent extended power outages caused by Cyclone Gabrielle provide a good example of where customers may have been willing to pay for a more resilient network.

Part 4 of the Commerce Act objectives should be expanded to also include resilience to emergency events. Specifically, "have incentives to improve efficiency and provide services at a quality and resilience that reflects consumer demands". The definition of quality could also be expanded to include network resilience to emergency events. EDBs are already considered lifeline entities under the Emergency Management Act 2023, (to replace the Civil Defence Emergency Management Act 2002). For EDBs to conduct their obligations under this Act, the regulators also need to reflect these responsibilities in their decision-making.

4.43 Is there a case for central government to direct the Commerce Commission, when dealing with Electricity Distributors and Transpower, to take account of climate change

objectives by amending the Commerce Act and/or through a Government Policy Statement (GPS)?

Yes, there is a case for the government to use a GPS to include objectives for the Commerce Commission on emissions reduction and resilience. In 2016, the GPS for WELL allowed CDEM requirements for earthquake readiness to be part of Part 4 considerations by the Commission. This approach was effective in reducing regulatory expenses and time through a more streamlined approach.

There is also an opportunity for MBIE to include IPP for distribution networks in Part 4 of the Commerce Act. An IPP would effectively allow distribution networks to prudently invest in their networks for price, quality, resiliency, and decarbonisation over a period beyond the 5 year CPP restriction.

4.44 If you answered yes to question 43, please explain why and indicate:

What measures should be used to provide direction to the Commerce Commission and what specific issues should be addressed?

How would investment in electricity networks be impacted by a direction requiring more explicit consideration of climate change objectives? Please provide evidence.

As outlined in our response to 42.

The inclusion of network resilience in Part 4 objectives would require networks to consider what level of resilience their customers want and whether they would be willing to pay for the investment needed to deliver that level of resilience. Like the current price/quality trade-off, networks would need to establish the price/resilience trade-off and reflect that trade-off in their investment plans.

5 Part 4: Responsive Demand and Smarter Systems

5.45 Would government setting out the future structure of a common digital energy infrastructure (to allow trading of distributed flexibility) support co-ordinated action to increase use of distributed flexibility?

In addition to providing customers access to the ‘value stack’, flexibility services will play an important role in maintaining distribution network security. As part of our response to the May 2022 Emissions Reduction Plan (ERP), we have started to model and test the impact of connecting EV chargers and other devices to the network. Our studies are showing that these devices are much larger than what Low voltage (LV) networks in New Zealand have been designed to accommodate. The simultaneous operation of large DER risks causing networks to exceed their security limits. EDBs at present have no visibility of where these devices are connecting and have no way to ensure that they will operate within the network operating constraints. EDBs will not be able to meet their regulatory quality expectations if the connection and operation of these large DERs are not managed.

We strongly support a common trading platform for the reasons provided in the paper. A common platform would also provide an important tool for managing the secure connection of large new devices and well as providing a platform that customers can use to access the flexibility value stack. We note that South Australia has been using a similar approach to manage household solar which they have used to avoid widespread outages due to very low voltages.

The scope of the platform should include:

- Securely connecting large new devices: A platform for the mandatory registration and participation of large EV chargers and other large applications. This will provide distribution network visibility of where large devices are being connected and participation in flexibility services will ensure their operation remains within the network's operating standards. Once the device can be connected securely, a customer can choose to what extent they want to participate in other flexibility services.
- Maintain network security (implement an industry-wide hierarchy of needs): Network operators (EDBs and Transpower) have been able to maintain a secure electricity system by having priority access to hot water ripple control in emergency situations – emergency situations being when direct intervention is needed to 'keep the lights on'. These are rare events that would have a limited impact on competing flexibility services. The Electricity Code currently provides this capability for hot water ripple control via the default distributor agreement (DDA). EDBs can call on hot water assets managed by a retailer in an emergency, as can the grid operator. This capability needs to expand to devices managed by flexibility providers not currently captured in the code. This capability will ensure a stable and secure electricity system that flexibility services can be built on. A common platform would allow a hierarchy of needs to be applied consistently and fairly.
- Streamline application of common communication protocols: A common platform would allow common protocols to be applied between the platform and flexibility buyers and sellers.
- Fair and consistent pricing: A common valuation and pricing methodology for services traded allowing customers to receive a fair price for participating.

5.46 Should central government see how demonstrations and innovation to help inform how trade of flexibility evolves in the New Zealand context, before providing direction to

support trade of distributed flexibility? If yes, how else could government support the sector to collaborate and invest in digitalisation now?

No, we think a common platform should be a priority to ensure that large devices can be connected securely and the 'lights stay on' while New Zealand rapidly electrifies. The platform should start as a registration tool for large devices before evolving into a more complex trading platform.

Important lessons can be learned from South Australia and the rapid uptake of solar. The connection process was not initially managed and the rapid growth and injection of solar back into the grid caused widespread outages. Emergency measures were put in place which introduced a common platform that could aggregate and manage the injection of power back into the grid. Rules were introduced that allowed solar owners to operate freely if they could be managed when the network was constrained. It took an emergency and widespread outages to provide the impetus to introduce common platforms. South Australians can now benefit from selling their excess power with limited restrictions while also maintaining reliable electricity.

The rapid uptake of electric vehicles could, and will without quick intervention, create similar issues in New Zealand. Distribution networks do not have visibility of large new devices connecting to their networks and they cannot manage those devices to ensure they remain within the operating limits of the network.

As the DER dependencies and risks for network security are moved further away from the GXP, there is an opportunity to make the platform for flexibility at an ICP level. Exposing data, enabling control and operations at this level will make it more efficient to run networks and account for losses that are currently absorbed by distribution networks.

5.47 Aside from work already underway, are there other areas where government should support collaboration to help grow and develop flexibility markets and improve outcomes? If yes, what areas and actions are a priority?

Our EV Connect Roadmap and the Flex Forum Flexibility Plan 1.0 provide all the actions needed to develop flexibility services.

We provided the priority actions from The EV Connect Roadmap in our response to the Electricity Authority's 'Updating Regulatory Setting for Distribution Networks' consultation. The most important actions are to coordinate the implementation of the priority actions and then provide the coordinating body with a government mandate to make the changes needed. The Flex Forum has started the first action but needs government support to turn the Flexibility Plan into action. The priority actions are:

1) Co-coordinated implementation: Our EV Connect programme identified industry leadership as a key driver for the development of flexibility services. The actions required span the flexibility supply chain and need a coordinated approach. We believe MBIE or the Electricity Authority are well placed to partner with the industry to provide the mandate and/or influence to make the regulatory changes needed.

2) Understand consumer preferences for flexibility services: For flexibility services to be developed to scale and not provide a viable wire alternative, customers must have IP connected devices that can be remotely managed and be willing to participate in flexibility services. The industry must develop services that customers are comfortable participating in.

3) Implement an industry wide hierarchy of needs: Network operators (EDBs and Transpower) have been able to maintain a secure electricity system by having priority access to hot water ripple control in emergency situations – emergency situations being when direct intervention is needed to 'keep the lights on'. These are rare events that would have a limited impact on competing flexibility services. Currently, the Electricity Code provides this capability for hot water ripple control via the DDA. EDBs can call on hot water assets managed by a retailer in an emergency, as can the grid operator. This capability needs to expand to devices managed by flexibility providers not currently captured in the code. This capability will ensure a stable and secure electricity system that flexibility services can be built on.

4) EDBs to develop a LV management capability: Forecasting where flexibility will be needed and incorporating flexibility services into their asset demand response will allow EDBs to identify network constraints and where flexibility services could be a viable wire alternative. LV Management systems combine spatial GIS data with ICP level consumption and power quality data to forecast demand and network capacity constraints. These systems are complex and will take time to develop. LV management is a precursor to Distribution System Operator capability.

5) Streamline access to ICP level data: EDB LV management systems require ICP data – without the data, EDBs have no visibility of LV constraints or where they could use flexibility services. The provision of ICP data includes ensuring all privacy responsibilities are met.

6) Ensuring DERs are IP connected and are participating in flexibility services: This includes ensuring all large DERs are visible and registered with a flexibility provider – so that EDBs can ensure they are connected securely, and their continued operation remains within the network security limits.

7) Flexibility provider tools that coordinate DER and aggregate a demand response: Flexibility providers need to develop the capability to aggregate and coordinate the management of multiple DERs. The tools must have common communication protocols that allow services to be coordinated with buyers.

8) EDBs are funded to develop and purchase flexibility services: EDBs are not funded to purchase flexibility services. They do not have OPEX allowances to purchase services and the IRIS mechanism does not allow OPEX/CAPEX substitution if the deferred CAPEX benefits span multiple regulatory periods. Until EDBs have regulatory allowances to purchase services, their use of flexibility services will be limited to small-scale trials and tariff services. This is being discussed as part of the IM review.

As flexibility services mature and there are multiple buyers and sellers, EDBs will need to evolve their LV management capability to a Distribution System Operator (DSO) function. At this point, the Authority will need to consider what regulatory settings will be needed to support a DSO. As flexibility services are used more extensively and services are provided up and down the electricity system, their use will need to be coordinated to maintain the whole of system security. Central to this will be establishing a clear hierarchy of needs or services that the electricity system can use to prioritise and coordinate multiple purchasers/users of flexibility.

Importantly, we do not believe that whole of system coordination using a central controller of the end-to-end network, will allow networks to maintain accountability of their quality performance. Networks have regulatory quality targets applied under Part 4 of the Commerce Act 1986 (SAIDI and SAIFI targets) and power quality obligations under the Electricity Act and the Code (including ensuring that voltage remains within the 6% limits). EDBs must retain the ability to manage network security to meet their regulatory obligations they are accountable for.

5.48 Could co-funding for procurement of non-network services help address barriers to uptake of non-network solutions (NNS) by electricity distributors?

There are two funding issues to resolve to support the development of NNS as a viable alternative to traditional wire solutions. (1) Funding innovation so that networks can trial and test NNS and develop the tools and processes needed to incorporate NNS into their demand response (2) to purchase flexibility when they offer a more economic solution to building a wire solution.

We believe it is important that price/quality regulation provided by Part 4 of the Commerce Act addresses distributor regulatory funding to ensure that there is an appropriate balance between what customers pay and the service quality they receive and that regulatory risks are borne by the party's best place to mitigate them. Co-funding provides a useful source of innovation funding (EECA co-funded our EV Connect project) but we believe that the level of funding should be coordinated by the regulatory framework to ensure distribution services are efficient and provided in line with the regulatory objectives.

1) Funding innovation

We would strongly support co-funding innovation using the $20m fund if it was part of a targeted approach to innovation which ensured that the overall level of innovation funding needed to develop flexibility services was appropriate and that the innovation programmes were co-ordinated to deliver the new capability identified in the EV Connect Roadmap and the Flexibility Plan 1.0.

We would not support an uncoordinated or untargeted approach as it could lead to the continued underfunding of innovation or inefficient use of the innovation funding. Our submission to the Commerce Commission's Draft Input Methodology decision highlighted our concerns about the lack of innovation funding needed to support the development of the ability to use NNS. These new abilities are not trivial capabilities and will need substantial investment in resources, time, tools, and funding. Our current innovation projects are showing that the implementation costs are material with the cost of data, software, expert advice, and the expected flexibility purchase costs are adding to more than the existing allowances.

Other judications have also shown the level of investment needed to develop flexibility. The UK electricity regulator initially provided a £500m fund to try out new technology, operating and commercial arrangements and then moved to an innovation fund of up to £81m p.a. Figure 1 provides the actual funding awarded for distribution system operator (DSO) related innovation projects in the UK up until 2019. The figure is from the 'Innovation Mapping to Identify Distribution System Operation Gaps – Closedown Report' produced by the Energy Networks Association in the UK.

Figure 1 – Flexibility related innovation spend in the UK.

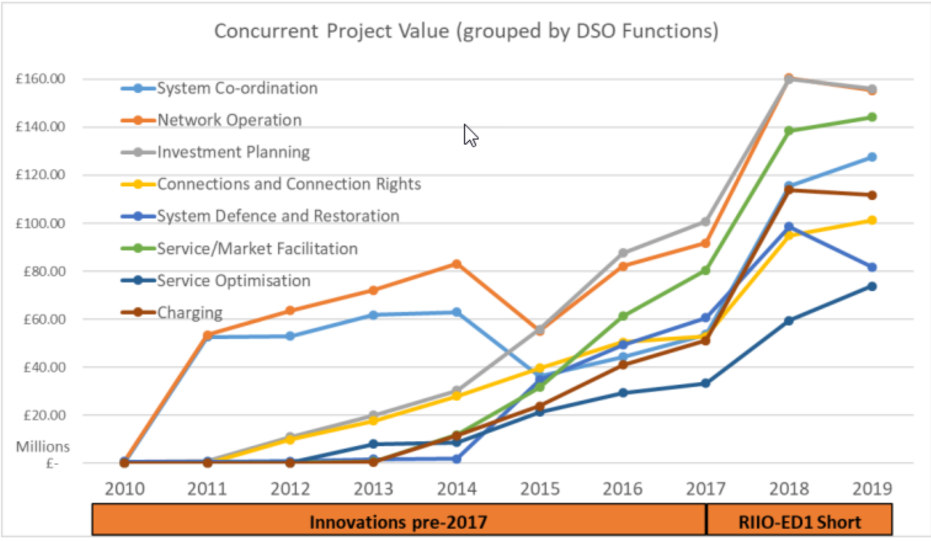

Figure 10 **Value of DSO Innovation Activities Running Concurrently up to 2019 by DSO Functions**

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

2) Purchasing flexibility

Networks will need allowances to purchase NNS when more economic ways of providing new capacity than building traditional wire solutions (assuming EDBs have developed the tools to use flexibility). The ongoing funding for NNS must be funded by the regulatory model to ensure regulatory efficiency incentives can be effectively applied. It would not be appropriate for an external fund to pay for these services because this would incentivise NNS even if it would be more efficient to build traditional capacity.

The Commerce Commission Input Methodology consultation considered how networks will fund NNS. The draft decision is to provide an allowance for purchasing flexibility due to the IRIS not being able to substitute CAPEX and OPEX across regulatory periods.

Our submission notes that forecasting allowances to purchase NNS is very difficult, and the forecasts are unlikely to be accurate because of the uncertain forecast inputs:

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

We note that the Commerce Commission will need to be comfortable with uncertainty in forecasts.

5.49 Would measures to maximise existing distribution network use and provide system reliability (such as dynamic operating envelopes) help in New Zealand? If yes, what actions should be taken to support this?

The development of dynamic operating envelopes will be an important tool for managing network security. EDBs will need to develop this new capability as part of the wider toolset they will need to incorporate NNS into their demand response.

Access to innovation funding to develop and trial dynamic operating envelopes and other new capabilities like LV management will be essential. The Flex Forum and the ENA’s Future Networks work programme are well placed to co-ordinate this development.

5.50 What do you think of the approaches to smart device standards and cyber security outlined in this document? Are there other issues or options that should be looked at?

We support the approach to smart

device standards and cyber security. CER will need a minimum level of capacity to be able to participate in flexibility services. We also agree that customers should be confident that their devices cannot be hacked and that they will be able to participate safely in flexibility services.

Industry forums like the Flex Forum, ENA's Future Networks Forum, and the EEA's Flex-talk programmes are well placed to provide input into device standards. However, protocol should be an open architecture and not limited to one type.

In addition to mandating devices have smart functionality (IP connected) and a default off-peak operating setting, it should be mandatory for large CER to be registered to a flexibility provider. Low voltage networks are not designed to accommodate high penetration of devices like large EV chargers. To maintain a secure electricity supply, EDBs will need to know where large EV chargers are connecting and could turn those devices down if they are being used during peak demand periods and the networks are at risk of exceeding their operating limits. This will be a critical capability to manage the rapid uptake of EV's while a market for flexibility services is being developed.

5.51 Do you think government should provide innovation funding for automated device registration? If not, what would best ensure smart devices are made visible?

We agree that EV visibility is critical, and we support a registry. We also think that automated device registration would need additional mechanisms to be effective because:

- A registration process would rely on a manual entry of the registration information. Experience in the UK is that many registrations are missed, and the data set was not complete.
- The vehicle registration address does not necessarily relate to where the vehicles will be charged. Waka Kotahi provided anonymised registration information and we found that the registration addresses related to locations that were different from the charging point.

We think that a combination of information sources would be most effective:

- A registration process as proposed.
- EV detection using smart meter data (this assumes that EDBs have funding to develop a LV management tool and to purchase smart meter data).
- Consumption and location data from the IP connected device itself (assuming the device is participating in a flexibility service and the requirement of that service is to provide consumption data).
- Dynamic connection agreements for charging >2.5kw for load shifting.

The registry could also be used to register large devices to a flexibility service. This could be part of the common platform considered in question 45.

5.52 Are extra measures needed to grow use of retail tariffs that reward flexibility, so as to support investment in CER and improved consumer choice and affordability?

We believe that retailer tariffs will naturally evolve to include better price signals for flexibility as:

- Competition grows from non-traditional retailers (and non-retailer) providers who specialise in aggregating and managing IP connected devices.
- Stronger peak demand price signals from EDBs as their prices become more cost-reflective and emissions reduction-related investments are included in peak demand price signal calculations.
- The low fixed user restrictions are removed providing more cost-reflective signals for both retailers and distributors.
- Customers understanding the value they can provide and looking to be able to participate in flexibility.
- Retailer competition to attract customers with IP connected devices to participate in their flexibility service.
- Demand-side management should be rewarded for reducing wholesale electricity prices as well as not requiring network investment.

5.53 Should the government consider ways to create more investment certainty for local battery storage? If so, what technology should be looked at for this?

Household batteries are just one way of providing flexibility services. EV batteries and hot water appliances are the two largest drivers of forecast decarbonisation-related demand increases and are best suited to participate in flexibility (that demand can be shifted to off-peak periods while not impacting the quality of life). Batteries will also provide a good supplement for transformer capacity and support LV network as additional reinforcement is built during the transition.

Rather than focusing on providing investment certainty for batteries, the focus should be on developing pricing methodologies for flexibility services that reward customers for shifting electricity use away from busy periods and for providing a level of network reliability themselves (for devices that can store electricity).

5.54 Should further thought be given to making upfront money accessible to all household types, at all income levels, for household battery storage or other types of CER?

The Boston Consulting Group, 'The Future is Electric' shows that electrification will increase household electricity bills through fossil fuel conversion, which WELL expects a 26% increase in network investment, but will reduce total household energy costs by 35%. The biggest contributor to the cost reduction being swapping a petrol /diesel vehicle with an EV.

EV batteries are also much larger than household batteries and the technology that allows EV batteries to be used in the same way as a household battery is rapidly developing. We support making upfront money assessable to invest in EVs to provide those in energy hardship access to the household cost savings that electrification can provide as well as the benefits that a household battery can also offer (as provided in the paper). It is necessary to have a registered system and coordinated procurement of flexibility services so that CER does not create network stability issues.

The electrification components of the Emissions Reduction Plan will lower household electricity prices and we think it is important that these savings are available to all sectors of society.

5.55 Should government think about ways to reduce 'soft costs' (like the cost of regulations, sourcing products, and upskilling supplier staff) for installing local battery storage with solar and other forms of CER/DER storage? If so, what technology should be looked at?

Yes, we would support reducing soft costs for CER which focuses on devices that can be used to participate in flexibility services (EV chargers, electric hot water, solar/battery, etc). Of foremost importance, CER/DER should be installed at Civil Defence Centres for community resilience and be government funded.

5.56 Is a regulatory review of critical data availability needed? If so, what issues should be looked at in the review?

Streamlined and ready access to data (smart meter consumption and voltage data and CER location and specification data) is essential to enable EDBs to incorporate flexibility services into their demand response.

The issues and possible solutions were covered in the Electricity Authority's 'Update to Regulatory Settings for Distribution Networks' consultation. The need for a regulatory review will depend on whether the final decision from the Electricity Authority will solve the issues. The Electricity Authority has the mandate to correct these issues so we hope they will do so. However, this consultation was seven months ago, and the lack of data is slowing EDBs developing the LV visibility tools needed to use flexibility.

6 Part 5: Whole-of-system considerations

6.57 What measures do you consider the government should prioritise to support the transition?

The government should prioritise making data from smart meters more transparent through a controlled central registry. The focus of most system disruptions is at ICP level, and this is the area that has the least available data. The current setup allows some participants to have access to this data and others to pay for it. In the end, the costs are passed through to customers to fund initiatives that will gain from the data use.

6.58 Are there gaps in terms of information co-ordination or direction for decision-making as we transition towards an expanded and more highly renewable electricity system and meeting our emissions goals? Please provide examples of what you'd like to see in this area.

Market measures do not operate beyond the GXP and many of the framework challenges are occurring 'behind the meter' at ICP level. There is no coordinating government body that is responsible for ensuring the multiple components of the electricity sectors part of the Emission Reduction Plan, are being planned for and delivered.

The electricity sector has formed a working group on the back of the Boston Consulting's 'The future is Electric' delivery path to track progress against the plan. MBIE has been involved in the formation of this group and the Industry Accord new framework, formalising each party's commitment.

The coordinating government body could be set up to work with industry to ensure the plan is delivered and to ensure legislation, policy, and regulation support the work programme.

6.59 Are there significant advantages in adopting a REZ model, or a central planning model (like the NSW EnergyCo), to coordinate electricity transmission investment in New Zealand?

Would a REZ model for local electricity distribution be an effective means of addressing the first-mover disadvantage of connecting to electricity distribution networks?

We would support a co-ordinated approach that improves the visibility of renewable investment and the delivery of the Emissions Reduction Plan. This would help ensure that generations, transmission, and distribution investments were correctly timed, and the resulting new capacity is planned for through projects or consenting as much as possible.

We do not think a REZ model is needed for local distribution networks to address first-mover disadvantages. As outlined in our response to Chapter 8 questions, we do not believe the first-mover disadvantage is an issue for all networks. We have supported Meridian Energy Limited generation into the WELL network to lower connection costs required at the transformer level for

We think a less expensive solution is to ensure the regulatory models provide adequate funding for networks to invest and to include that investment on their regulatory asset bases (the costs then being recovered via tariffs over the asset life). This includes ensuring that the investment paths are financeable so that networks can borrow at a cost that is aligned with the regulatory debt allowances. A pre-requisite would be the visibility of DER/CER needed to factor into network investment paths. Once networks are confident, they can fund the additional investment requirements, and secure new capital by new debt and equity from their owners or by finding new investors.

6.60 Should MBIE regularly publish opportunities for generation investment to enable informed market decision-making?

We see this a useful tool to attract investors, especially from overseas where they may not be as aware of the opportunities. However, due to the topography of New Zealand, it is often the transmission cost that makes some investments inviable. This data would also need to be indicated for clarity to potential investors.

6.61 How should the government balance the aims of sustainability, reliability and affordability as we transition to a renewable electricity system?

6.62 To what extent should wholesale, transmission, distribution or retail electricity pricing be influenced by objectives beyond the (affordability-related) efficiencies achieved by cost-reflective pricing, such as sustainability, or equity?

We think it is important to not mix up cost-reflective price signals with other objectives like affordability. As outlined in the paper, markets achieve lower prices in the long run. When efficient pricing signals are used for generation, network, and technology investments in the right place and at the right time, it brings down prices for everyone. Inconsistencies and opacity will send mixed signals that lead to cross-subsidisation and mirky outcomes.

We think it is the job of a separate social welfare mechanism to redistribute wealth for equality reasons. Keeping a clear distinction between the different purposes of price and welfare mechanisms (and a clear separation of the application of these functions) will allow stakeholders to monitor how each function is achieving its purpose. Mixing welfare measures with pricing creates unintended consequences and makes it difficult to measure if either function is effective.

A good example of how prices with social welfare mechanisms can create unintended consequences is the low fixed user restrictions that limit the fixed chargers on low-energy users. To meet the restrictions, EDBs have had to increase prices for standard users, creating unintended cross-subsidies:

- Higher prices for large families in uninsulated homes as higher energy users, (who are often in energy hardship), to subsidise small families in insulated homes.
- Lower prices for wealthy homes who can afford solar which lowers the overall energy levels, providing access to low user prices. Networks have capacity during the day and solar provides no network benefits from reducing demand and still contributes to the evening peak demand.

The low fixed user tariffs are being phased out and this should allow networks to have more cost-reflective tariffs across all user groups that contribute to the network operations.

6.63 Are the current objectives for the system's regulators set in law (generally focusing on economic efficiency) appropriate, or should these also include more focused objectives of equity and/or affordability?

We agree that a careful balance is needed between efficiency and affordability but as outlined above, any wealth redistribution should be done separately and after economic efficiency. Consideration should also be given to how can less-wealthy people have access to the household energy cost savings that electrification will provide (i.e., access to an EV).

General Comments:

It is imperative that when the government implements new measures to combat market challenges, there is greater consideration for the unintended consequences on the rest of the market participants. An example of this is the change to real-time pricing (RTP) in 2022. The unintended consequence of RTP for distribution networks is the overreach by the system operator to distribution network-connected customers. This disrupts the visibility of managed demand for distribution network performance (quality), security and reliability. It also undermines the end goal of RTP as networks are now unable to offer full demand response if a portion of their demand response is cannibalised by the SO which connects to the distribution network. The EDB is unable to place with certainty a clear bid for demand curtailment if the SO has created an overlap with distribution customers. If a portion of demand-side management is reserved for the SO only, then EDBs cannot make use of this resource at other times. The lack of visibility and information transparency leads to ill-informed decisions and creates inefficient market responses and network stability. There are also legal implications for contracts setup between distributors and retailers (DDA's) when these arrangements are broken from a third-party instigator (SO). Future changes need to continue the coordination between market participants that incentivise demand response and flexibility services that drive competition and operational efficiencies. The SO calling for distribution connected RTP offers disrupts a coordinated supply system and undermines the support that EDB’s could provide under Grid Emergency Warning Notices when they had full visibility of the distribution demand-side availability.