wellington electricity™

Pricing strategy & roadmap

Prepared May 2021

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A copy of this Pricing Road Map and our Pricing Methodology can be downloaded from www.welectricity.co.nz/disclosures

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1 Introduction

Wellington Electricity Lines Limited's (**WELL**) is an Electricity Distribution Business (**EDB**) who is responsible for providing electricity distribution services in the Wellington region. We manage the poles, wires and equipment that provide electricity to approximately 400,000 customers in the Wellington, Porirua, Lower Hutt and Upper Hutt areas. We take electricity from Transpower's national grid, to residential homes, commercial and industrial businesses and Wellington's essential infrastructure assets like hospitals, water plants and air and sea ports.

We are investing around **$161m** in infrastructure on the Wellington network in the next 4 years.

We provide electricity to over **171,000** households and to **400,000** people in our community.

Our total network is around **6,700 km** in length with over **4,100 km** of it being underground cables.

We have around **4,000 substations** and **40,000 poles**.

There are about **2,000** electric vehicles connected to our network

We recover the cost of owning and operating the network through a combination of published tariffs and capital contributions for new connections. WELL is regulated by the Commerce Commission (**Commission**) and the Electricity Authority (**Authority**) and is required to publish how prices are calculated, what prices are for the upcoming pricing year and how much revenue it expects to collect from those prices. Our pricing disclosures can be found on our website at https://www.welectricity.co.nz/.

We also publish a Pricing Roadmap which summarises our plans for changes to prices and pricing structures, together with expected timeframes and progress updates. Our first Pricing Roadmap was published 2017 and we have been providing process updates in our Pricing Methodology pricing disclosure. We have made good progress against the original actions and we now need to refresh the roadmap so that it reflects advances in our own thinking and changes in the industry.

This updated Pricing Roadmap will provide:

- A summary of network characteristics and capacity constraints on the Wellington network and their implications for our pricing strategy and price.
- A look at future energy use in Wellington and the impact on pricing. New Zealand's carbon neutral climate change targets in particular have important pricing implications.
- A Pricing Strategy that will ensure our future prices support us in delivering safe, reliable, cost effective and high quality electricity distribution services.
- An update on progress against the current roadmap.
- An overview of what we have learned over the last few years and the advances in our own thinking. This has led to new work programmes. One of those work programmes is an internal review of our own pricing structures and incorporating the Authorities new pricing setting methodology.
- A refreshed Pricing Roadmap which includes the new work programmes.

To simply our pricing disclosures we plan to combine the Pricing Roadmap and the Pricing Methodology going forward. This refreshed Roadmap will be included in the next iteration of the Pricing Methodology which is due for publication 31 March 2022.

2 Network characteristics and implications for pricing

Network prices have two purposes - (1) to recover an Electricity Distribution Businesses' (**EDB's**) allowable revenue that it needs to build and operate the network, and (2) to signal the future cost of using the network. Signalling the future cost of using the network means prices that reflect the cost of building additional capacity to meet increases in future demand on the network. The higher cost reflects that to meet those peak periods of demand in the future, a larger, more expensive network will have to be built.

Reflecting the higher cost allows consumers to make informed choices about how they will use their money – they could pay the cost to building a larger network or avoid that cost by using energy in the non-congested periods when the higher future costs are not applied. Accurately signalling the future cost of using the network will also let consumers make good investment decisions about purchasing appliances like solar and batteries or electric vehicles – customers can use prices to work out if the appliances could help save them money through energy savings or shifting more of there energy use to periods of the day when the cost of electricity is cheaper.

To set prices that reflect the future cost of using the network, a network operator must estimate what future demand will be. Specifically, to set tariffs that reflect the future cost of using the network, we need to know:

1. Where and when the network will exceed capacity;
2. What customer group is driving future energy use that is causing future capacity to be exceeded;
3. How much it will cost to build a larger network to meet the increase in future demand.

The electricity demand characteristics of a network will inform an EDBs pricing strategy and will guide the development of prices.

2.1 Future electricity use in Wellington

EDBs model future demand requirements as part of their Asset Management Plans (**AMP**). Our AMP can be found on our website at https://www.welectricity.co.nz/disclosures/asset-management-plan. Chapter 8 of our AMP forecasts future demand at each zone substation and models when that part of the network may run out of capacity. This model is used to plan how we will manage demand on that part of the network. WELL has a strategy of using load management tools (including peak demand period price signals and lower prices for consumers who provide us with hot water control) to delay having to invest in building a larger network for as long as possible. This helps us keep prices low. Where load management tools will no longer allow us to manage load within our security standards, we will increase the capacity of the network by building a larger network. This allows us to continue to provide a reliable electricity distribution services.

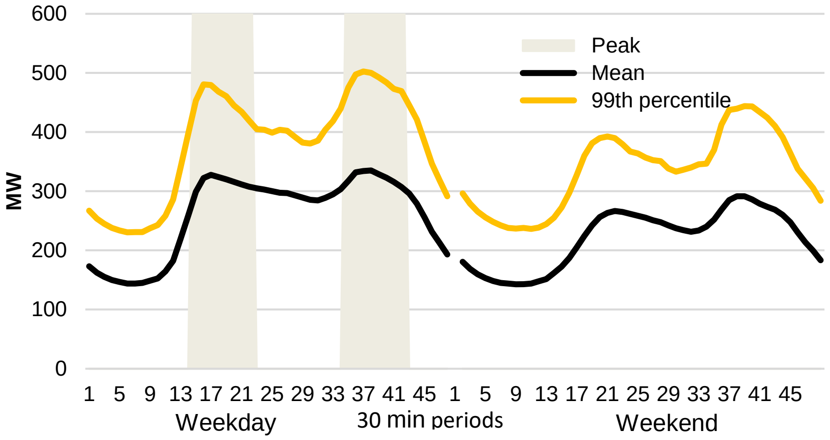
We will not repeat the demand forecasts provided in the AMP as we believe it is important to have a single, consistent view of future electricity demand. We do encourage readers to review chapter 8 of the AMP if they want to understand what is driving future investment on the Wellington network.

This Pricing Roadmap provides a summary of future demand characteristics in the context of pricing. We have combined information from the AMP with customer consumption data from of our Time of Use (**ToU**) pricing study[1]. To analysis the potential impact of ToU prices on residential customers, WELL analysed electricity consumption for 10% of our customers. Both residential and commercial customers were included in the data set to allow the customer groups to be compared. The demand data set was based on 30 minute increments to provide a detailed profile of customer demand.

2.1.1 General demand characteristics

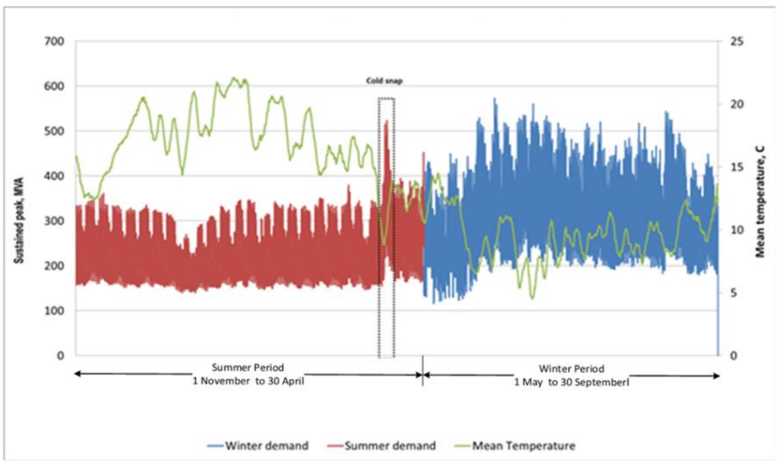
We have two predominant demand profiles on the Wellington network – parts of the network used primarily by residential consumers and parts used by commercial consumers. Residential consumers drive peak demand on the Wellington network, with the highest energy use being in the residential suburbs in the winter months when home heating is the highest. **Error! Reference source not found.** to 10 summarise the general demand characteristics on the Wellington network.

Figure 1 - Overall, Wellington is an evening peaking network



Energy use in Wellington is the highest during the morning as residential customer get ready for the day and in the evening when people are home and preparing dinner. The Wellington network has spare capacity during the day and at night.

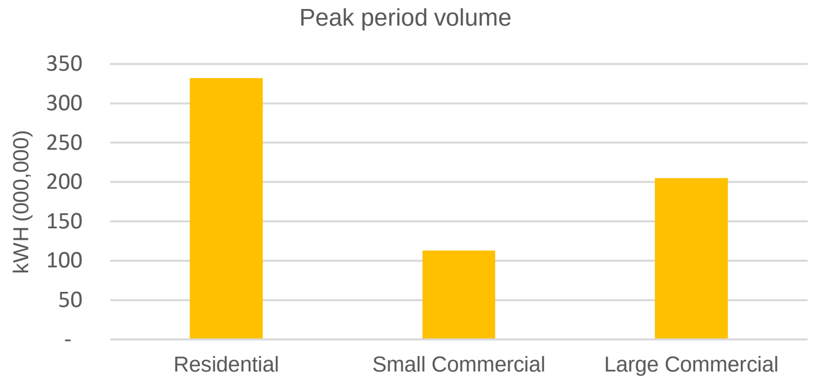
Figure 2 - Winters peaking network



There is a strong correlation between the demand profile and the ambient temperature. Energy use is higher in the winter (May to October) when consumers use more electricity to heat their homes.

[1] As part of our transition to ToU prices we implemented a detailed study customer consumption data. This analysis provided us with useful insights about how consumers use electricity.

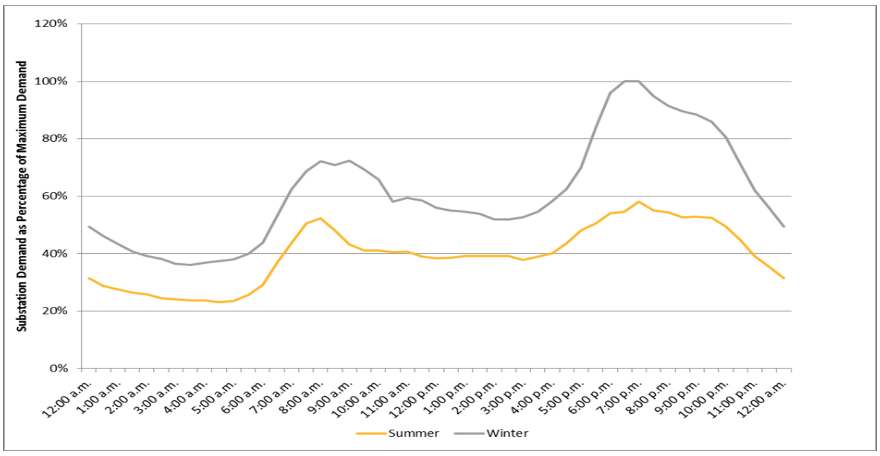
Figure 3 - Residential consumers drive peak demand on the network



The graph compares consumption during peak periods.

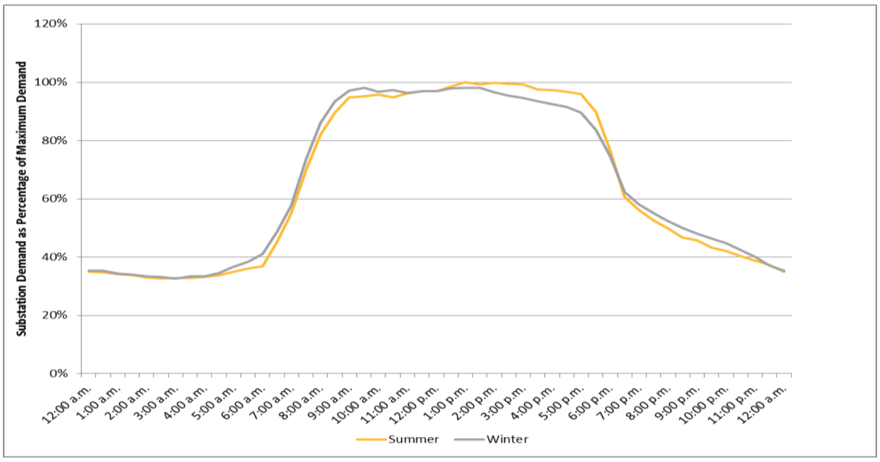
Residential consumers are the largest contributor to peak demand. Large commercial customers contribute significantly towards the morning network peak.

Figure 4 - Residential demand peaks during the week and in the evening



Residential consumer demand is the highest in the morning and evenings during the week. Demand still peaks in the morning and evenings on the weekend but not to the same extent.

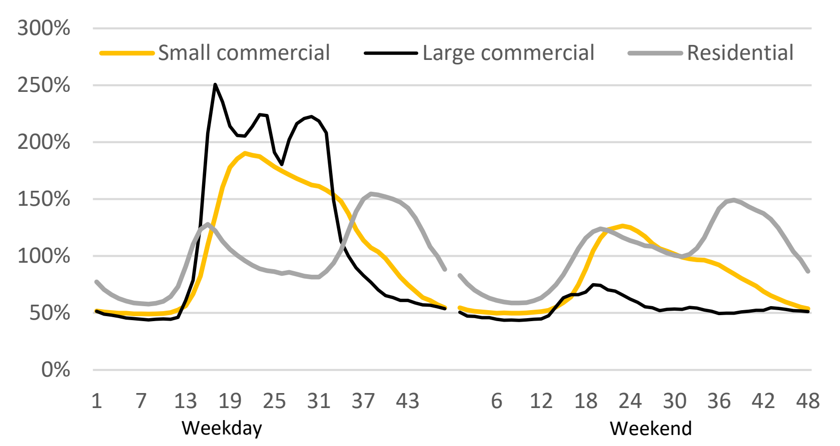
Figure 5 - Commercial demand peaks during working hours



The demand profile for commercial consumers peaks and then remains relatively flat through the day. There is also little difference in summer and winter demand.

Figure 6 - Commercial users have the highest enenery user per consumer

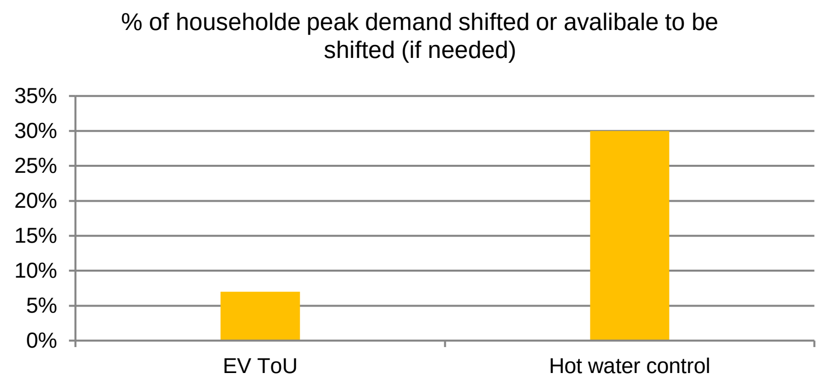
Demand per connection expressed as a proportion



of average demand shows commercial connections contribute towards the network's morning peak but not the evening peak. Commercial businesses demand is constant through the workday.

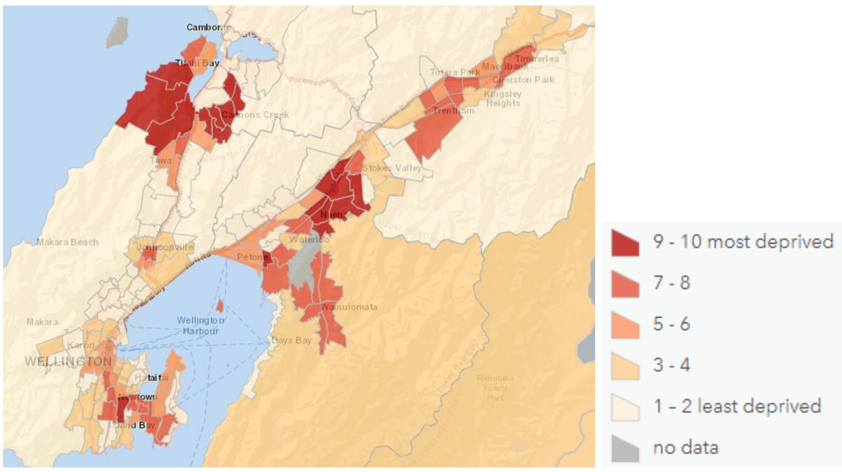
Residential consumers drive the networks evening peak.

Figure 7 - Directly managing demand is more effective than price signals alone



Our EV trial showed that education and price signals moved 7% of energy use away from peak demand. Hot water control provides the ability to move 30% of household away from peak demand. We only shift demand using hot water ripple relays if we need to.

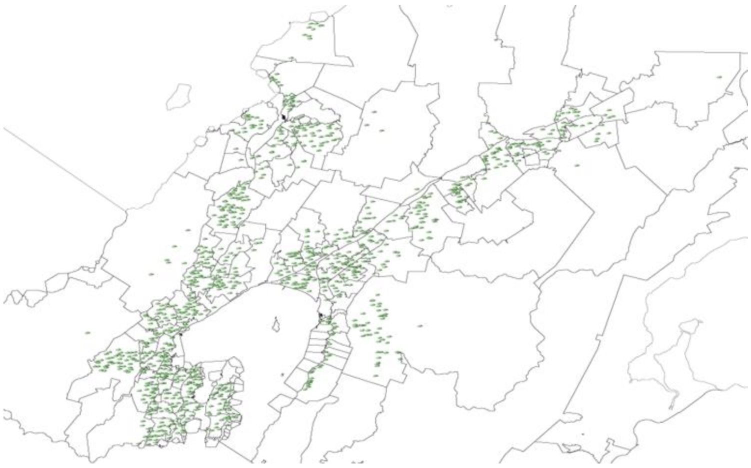
Figure 8 - Wide spread of household income levels[2]



Wellington has a wide spread of household income levels, including a large proportion who maybe experiencing energy poverty. We are cognisant of the impact that changing prices may have on this customer group.

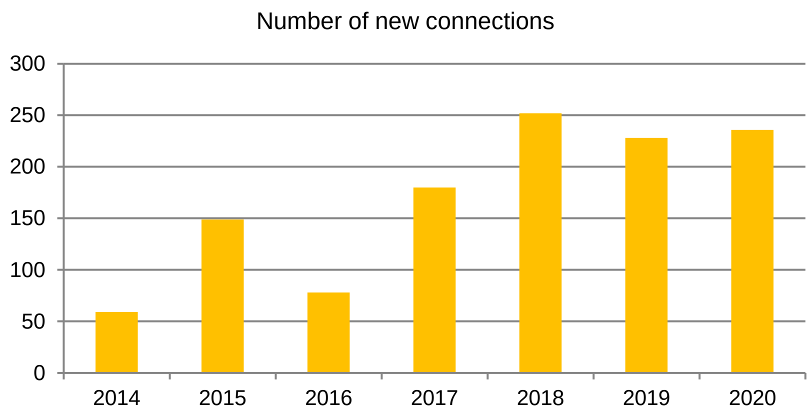
[2] From Environmental Health Intelligence New Zealand https://ehinz.ac.nz/indicators/population-vulnerability/socioeconomic-deprivation-profile/

Figure 9 - High EV uptake, evenily spread across network



EV uptake is evenly spread across the network. As of 2020, New Zealand Transport Authority reported that there were approximately 2,000 EVs on the Wellington network. EDBs do not have visibility on the number or location of EVs being installed.

Figure 10 - Low solar uptake

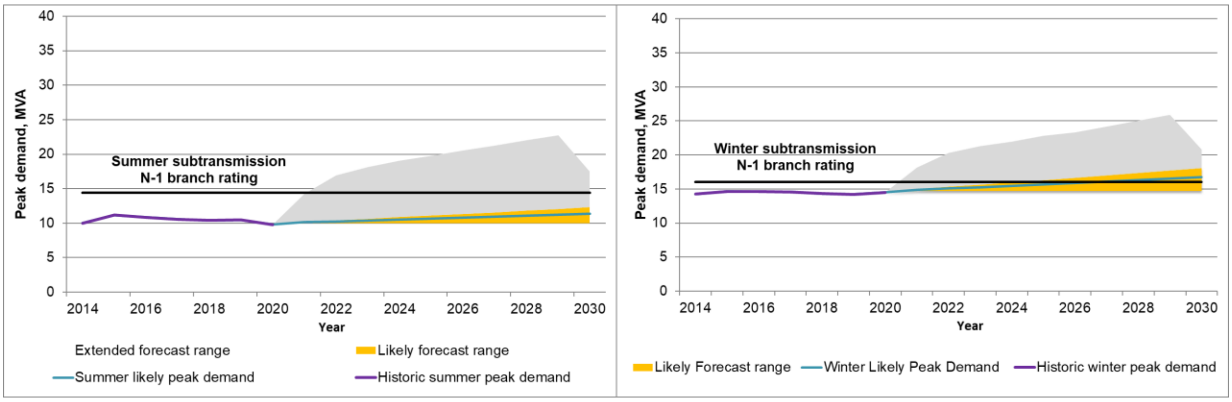


There is relatively low solar uptake in Wellington. As of March 2021, Wellington had 1,684 installations of solar with 6,185 kVA capacity – less than 1% of customers. Nationally, 1.5% of customers have solar.

2.1.2 Location demand forecasts

Chapter 8 of the AMP provides volume forecast for each zone substation. The volume forecasts provide a demand forecast range and an estimation of when demand may exceed constraints. As described earlier, WELL has a strategy of using load management tools (including price signals) to delay having to invest in building a larger network for as long as possible. In many cases where demand exceeds capacity, we will use demand management tools (including pricing signals) to shift demand to other parts of the network or to shift load to less congested periods. This helps us maintain one of the lowest distribution prices in New Zealand while operating one of the most reliable networks. An example is the Tawa Street zone substation, which is illustrated in Figure11.

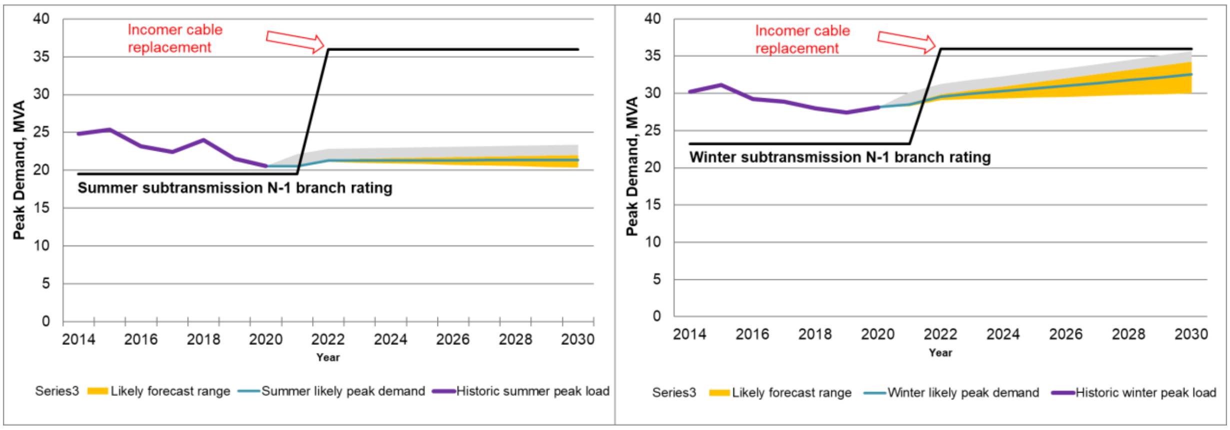
Figure 11 - Tawa street demand demand and capacity forecast



We expect that winter demand in Tawa may exceed capacity in 2024. We will use demand management tools to shift load away from the zone sub peak. We will also continue to monitor the winter load until we can no longer confidently provide a secure supply. We will then consider options to increase network capacity. As detailed in the AMP, we have nine zone substations where demand currently exceeds capacity, or where we expect that it soon will, and we will use load management tools (including price signals) to manage demand away from congested periods.

We also have some locations where we have decided that load management tools will not let us manage demand within the capacity constraints at some point in the future and that we need to increase network capacity. In these situations, we use price signals to delay when we will need to invest. While we may programme the investment to increase network capacity in the AMP, we continually assess network demand and will delay an investment if we can. Figure 12 from the AMP provides an example of this. Frederick Street is a commercial area that has a summer peak demand (due to office air conditioning). The demand forecast curve shows that demand has exceeded capacity in the summer for some time. We were able to delay investing in additional capacity by using demand management tools, including commercial prices with demand components that encourage reducing energy savings. We have now reached the point where energy use is expected to increase again and we can no longer hold off from investing.

Figure 12 – Fredrick Street demand and capacity forecast



We have nine zone substations where we have included an investment in the AMP to increase capacity and where we continue monitor demand and use demand management tools to delay when the investment is needed.

2.2 Impact of climate change initiatives

The Government has committed to reaching net zero carbon emissions of long-lived gases by 2050, and to reducing biogenic methane emissions by between 24-47% by 2050. The Climate Change Commission has been tasked with developing and implementing a plan of how these targets will be achieved. The Climate Change Commission's '*2021 Draft Advice for Consultation'* (**Draft Advise**) proposed priority areas of action needed to meet the targets. The actions included the electrification of light transport, transition from gas to electricity and to electrify manufacturing process heat. This will increase electricity consumption and the amount of electricity distributed to consumers across New Zealand. As highlighted by the Climate Change Commission, the capacity and capability of electricity distribution businesses will be an important consideration. Like electricity generation and transmission, electricity distribution networks (and the supporting legislation, policy and regulation) will need to grow and develop to ensure that the increase in demand and reliance on electricity as a primary energy source can be met. This growth is in addition to the network growth forecast in our AMP

Electricity is already an essential service, providing heating, cooling, cooking, appliance recharging, washing and other amenities needed to maintain healthy and happy lives. An important challenge will be meeting the climate change driven increase in demand while still maintaining a safe, secure and reliable supply for both existing and new services – this will mean developing extra capability and capacity as the climate change initiatives move from early adoption to being applied to all households and businesses.

2.2.1 We need to consider non-traditional solutions

Where new demand is higher than the current network capacity, the increase in demand is traditionally met by building a larger network – bigger cables, larger transformers and higher capacity equipment to deliver more energy. New factors mean that traditional delivery methods alone may not meet expectations of an affordable and secure delivery system:

- **The size of the increase in demand**: An initial calculation of the change electricity demand needed to meet the Draft Advice initiatives shows an 80% increase. This represents an unprecedented increase in demand outside of what the industry is currently structured to deliver.
- **Rapid uptake of new devices:** The uptake of new devices like electric vehicles (EVs) is expected to be rapid[3] and could occur across the entire network[4]. Construction of a larger network within an established urban environment takes a long time and it may be difficult to increase capacity of the entire network within the Commissions timeframes, without a large disruption to existing customers.
- **New technology**: New technology allows consumers to manage when their devices are used. Timers on electric vehicle chargers allow vehicles to be charged when the network has spare capacity. New battery technology allows batteries to be charged during less-congested periods, storing cheaper energy, and then used to access that cheaper energy when a network is congested to avoid higher congestion prices. The new technology also provides an opportunity for EDBs in the future to engage with consumers with battery storage to use this new technology to smooth network demand and allow more energy to be delivered through the existing network – an

[3] WELL's electric vehicle charging trial showed that an EV will increase household load by a third.
[4] WELL's EV Connect programme showed that EV growth to date was evenly spread across the Wellington distribution network.

opportunity to deliver new demand without having to build and pass to customers the cost of a larger network.

- **Cost impact:** Building a larger network is expensive. WELL estimates that if energy from EV's charging is not managed, it will increase peak demand by 80% which will cost hundreds of millions of dollars and increase prices by 80% (nominal) over 30 years[5]. A price increase of this magnitude could be unaffordable for a large number of consumers.
- **Time and resources needed to double the size of the network:** The significant increase in network investment will come at a time that other networks and the Transmission grid will also be growing. A finite pool of skilled resource in New Zealand could make this level of growth unrealistic.

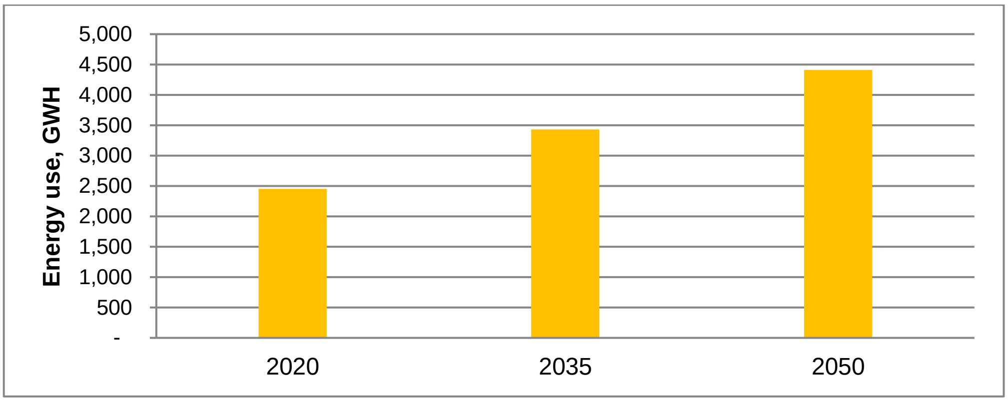
While the Climate Changes actions haven't been confirmed, The New Zealand government has committed to being carbon neutral and the most viable and likely solutions involve replacing fossil fuels with electricity. Building a bigger network alone is unlikely to be a realistic solution to meeting the significant increase in electricity use. As highlighted in our AMP and in section 2.1, the Wellington network has spare capacity in the day and at night. New solutions are needed to utilise this spare capacity to meet the Climate Change energy demands while delivering distribution services that are affordable and secure. Pricing will be an important tool to utilise the spare capacity.

2.2.2 The impact of the emission budget on electricity demand in Wellington

WELL has developed an initial high level view of the electricity demand requirements from the Climate Change Commissions Draft Advice. The analysis should be used as an indication only of the level and direction of change required. A more detailed calculation will be completed within the 20/21 regulatory year. The decarbonisation initiatives will be combined with our AMP investment programme once the Climate Change Initiatives have been finalised.

The decarbonisation initiatives are expected to increase electricity consumption on the Wellington network by around 80% per annum by the completion of the decarbonisation programme in 2050. While energy use will go up, we expect there will be an overall cost saving for households as they will be able to avoid purchasing expensive fossil fuels. Figure 14 compares current energy use now, in 2035 and in 2050.

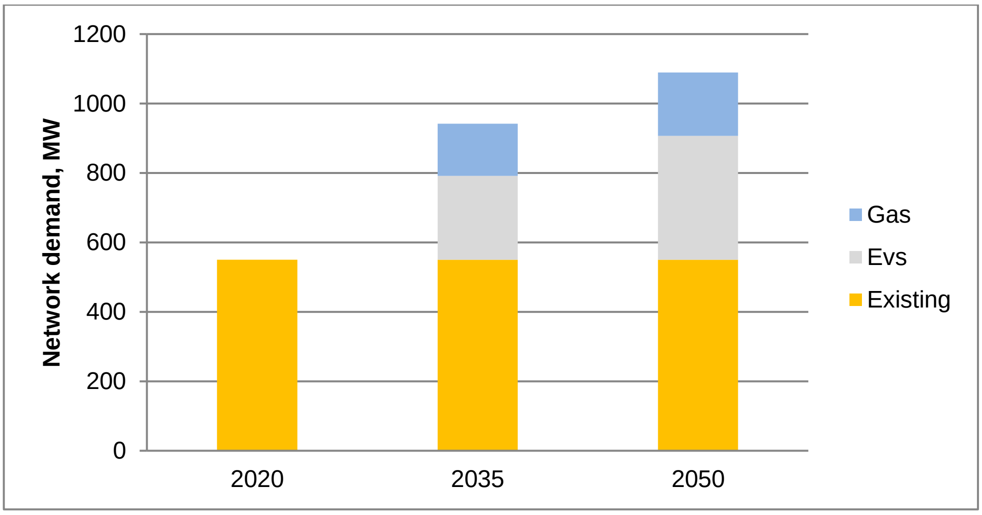
Figure 13 – increase in electricity use from the decarbonisation initiatives



[5] WELL calculated high level cost estimates for its response to the Climate Change Commissions Draft Decision. The cost estimates are high level and are only used for illustrative purposes. In particular, the price change does not take into account efficiencies from combining the network reinforcement with our asset replacement programme. More accurate estimates will be calculated as the climate change response is finalised.

How much capacity a network needs depends on demand during the most congested periods. **Error! Reference source not found.**5 estimates the increase in peak demand from electrifying the transport fleet and converting from gas to electricity and compares the change from now, 2035 and 2050. The figure shows that peak demand energy will double if current energy use patterns remain the same.

Figure 14 –The increase in peak demand from electrifying the transport fleet and converting from gas to electricity



If demand was not shifted away from the congested periods, WELL estimates it would cost $1b to build a network large enough to meet the expected demand by 2050. This represents an 80% (nominal) price increase to consumers[6].

2.2.3 Delivering new demand on the Wellington Electricity network

The Wellington network has capacity headroom available at low demand periods. Theoretically there is enough capacity headroom to meet the majority of the increase in demand from the decarbonisation initiatives if:

1. Customer behaviour can be changed so that energy use is moved away from congested periods on the distribution network to less congested periods that have capacity headroom.
2. Devices like EV charges, household batteries and space heating devices could be managed so that electricity is used away from congested periods on the network.
3. Consumers are comfortable trading off a lower level of quality for the lower price that using the capacity headroom can provide. The current headroom on the Wellington network is currently used to provide a high level of network security to assist a high reliability of service – the Wellington network is designed to allow electricity to be redirected across the network if a section of the network is short of capacity. If the spare headroom is used up, WELL will have less ability to re-direct electricity and the electricity supply will be less reliable.

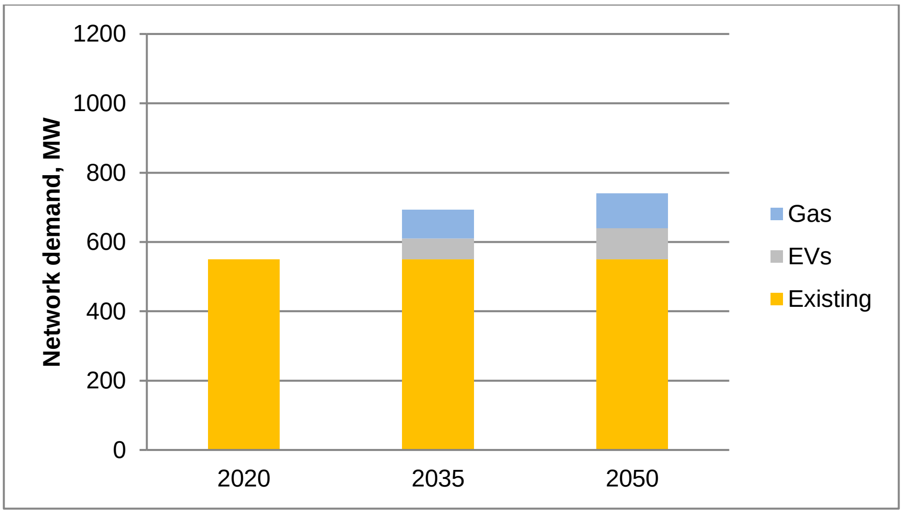
Realistically not all of the spare headroom can be used. Some headroom is needed to provide a buffer for providing unexpected increases in peak demand and to cater for consumer demand that cannot be shifted to less congested periods (for example, heating, cooking and other essential activities). The buffer also

[6] The cost estimates are based on high level estimates and are only used for illustrative purposes.

allows WELL to retain some of the ability to manage demand by redirecting electricity around congestion parts of the network.

EV chargers generally have the technology to schedule charging to off-peak periods while providing enough charge for vehicles to be used the next day. We expect the additional demand from the transition from gas to electricity water heating can also be shifted to off peak periods. The increase in demand from the transition from gas cooking and space heating to electricity is likely to remain in the peak congested period but has much lower volumes when compared to water heating. Figure 15 shows the expected increase in peak demand if some of the increase in electricity demand can be reasonable controlled.

Figure 15 - expected increase in peak demand if the load can be controlled



Controlling the load to move electricity consumption to less congested periods on the network means that peak demand will be 60% less than if energy use during peak demand wasn't controlled. This means that the investment in the network is also less – the increase in demand can be delivered by a smaller network. We estimates it would cost $0.5b and prices would increase by 40% to build a network large enough to meet the expected demand by 2050. This is half the cost of building the network if demand wasn't controlled.

2.2.4 Confirming the value of controlling peak demand

Utilising the spare network capacity during the day and at night appears to provide a viable way of meeting the climate change initiatives. Concept Consulting EV Study work programme supports this important assumption. While the findings are draft and are still being refined, they do support the strategy of using load control to meet the climate change targets.

The study analysed two points in time[7]:

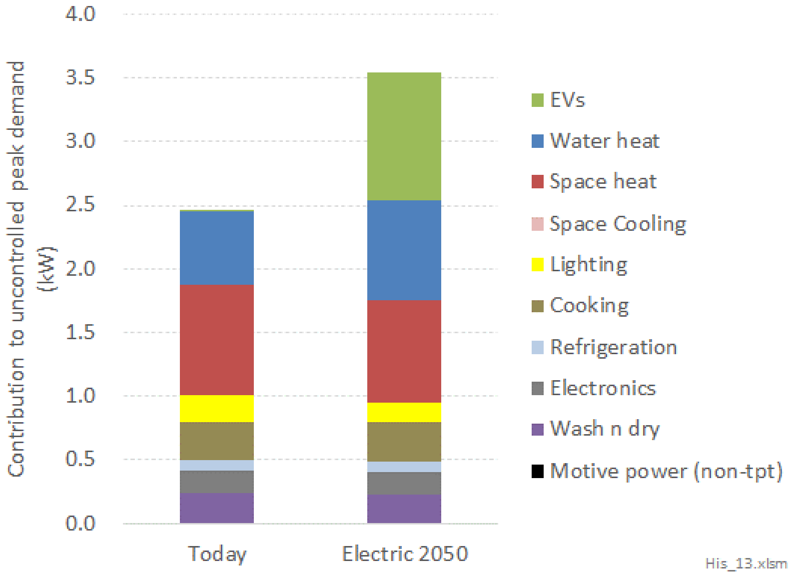
- 'Today', being a breakdown of electricity consumption between end-uses as per EECA's Energy End-Use Database[8]

[7] The key assumptions are natural gas and LPG space heaters all switch to heat pump electric, water heating all switches to electric, with 15% using heat pump cylinders (and the balance using resistive heating), household vehicles are all fully electric, and 20% of journeys shift to active or public transport, cooking is all switched to electric, and there are energy efficiency improvements across lighting (25%), space heating (15%), water heating (5%) and appliances (2.5%).
[8] https://tools.eeca.govt.nz/energy-end-use-database/

- 'Electric 2050', being the increase in average per household electricity consumption by 2050 assuming the degree of electrification proposed by the Climate Change Commission in its draft advice.

Figure 16 shows the estimated breakdown of average per household contribution to peak demand without any demand management – i.e., prior any appliance control or action by consumers to shift when they use an appliance. Prior to any demand management, the biggest driver of today's average uncontrolled household contribution to system peak is space heating, followed by water heating, then cooking, with other appliances driving the remaining 30% of peak demand. By 2050 they estimate that, if households have no incentive to manage when they charge their EVs, un-managed peak per household demand will increase by 45% - largely from EVs, with some increased contribution from water heating and small offsets from other uses. In total, EVs would represent 30% of un-managed peak per household demand.

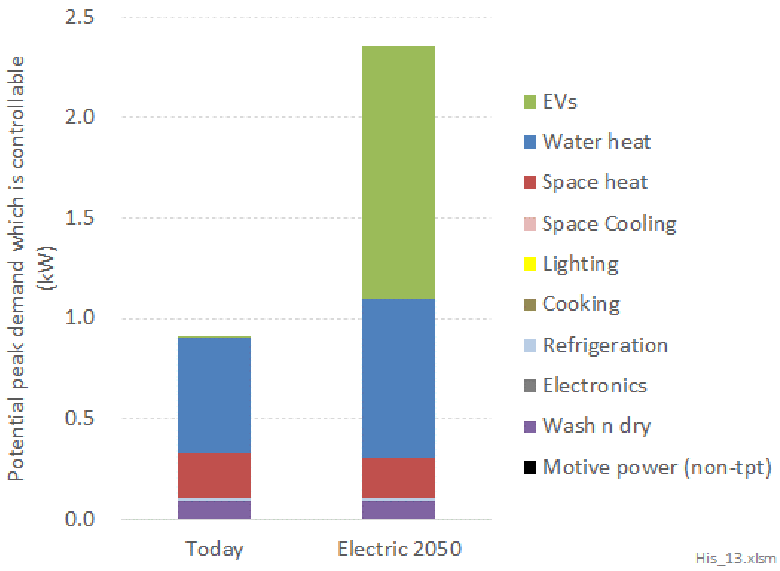
Figure 16 - Breakdown of average per household contribution to peak demand prior to any appliance demand management



The study looked at what appliances have the most potential for demand management. Figure 17 shows an estimated breakdown of the potential for demand management[9]. The key takeaway is that EV charging and water heating have, by far, the most potential for load management.

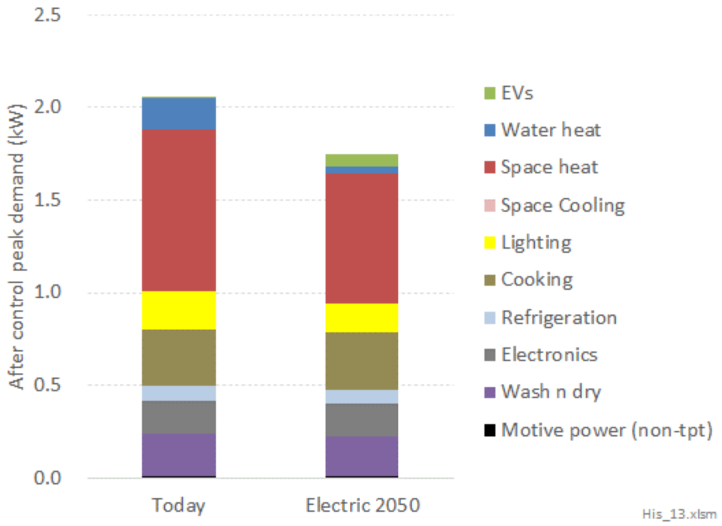
[9] The scope for easing capacity investment pressures depends on the size of the contribution to peak demand, and the extent to which the demand is time critical (1) some uses are inherently less time critical – for example, clothes and dishwashing are more delayable than lighting or cooking, and (2) other uses are non-time critical because the appliance has built-in storage that act as a buffer between supply and consumption.

Figure 17 - Breakdown of average household potential for appliance demand management during peak demand



The study combines demand growth and controllability to show a breakdown of peak demand with load management. Figure 18 shows that sustaining hot water control and adding EV management has the potential to eliminate capacity investment pressure from changes in average per household demand in the Electric 2050 scenario[10].

Figure 18 - Breakdown of average per household after-demand management contribution to peak demand



The study is also on a national basis. The Wellington network has the highest proportion of gas space heating in NZ and its urban environment is better suited to EVs than other networks. The potential for controlling peak demand is even higher in Wellington.

[10] Note, some efficient assumptions are also applied which means Figure 18 is not simply the addition of figure 16 and 17.

2.3 Conclusions

The key conclusions from the analysis of network characteristics are:

- Wellington is predominantly an urban network. Peak demand on the Wellington network is in the evening and in the winter. Residential consumers drive peak demand. The Wellington network has spare capacity in the day and at night.
- Where demand exceeds capacity, we will first use demand management tools (including pricing signals) to shift demand to other parts of the network or to shift load to less congested periods. Demand management tools provide important tools to allow us to delay investing in more capacity.
- In the future (assuming the current Climate Change work programmes will proceed) the accommodation of electric vehicles and transition from gas to electricity will be the largest drivers of peak demand in the future.
- While accommodating EVs will result in a large increase in demand, that energy demand is used for battery storage so is the easiest to move to less congested periods. EV technology enables owners to automatically charge during off peak periods and still have the charge needed to using the next day.
- The increase in energy demand from transitioning from residential consumers from gas to electricity is more difficult to move to off peak periods – gas for space heating and cooking will still be needed during peak demand periods. Some demand for hot water heating could be moved to off peak periods. Commercial gas displacement will require dedicated high voltage network investment to accommodate the scale of energy required.
- The majority of the expected increase in demand from the decarbonisation initiatives can be met by the existing residential network if demand from EV charging and hot water gas heating is shifted to less congested periods.
- To achieve this, WELL must develop and invest in demand management solutions and signal through cost reflective tariffs the incentives to shift demand away from peak periods – this will be a focus of WELL future work programmes.
- New services that allow EDBs to directly manage demand appear to be more effective than a price signal alone.
- In the future, consumers will need to be comfortable trading off a lower level of quality for the lower price that using the capacity headroom can provide. If the spare headroom is used up, WELL will have less ability to re-direct electricity and the electricity supply will be less reliable.

3 Pricing strategy

The analysis provided in chapter 2 highlights the current importance of demand management tools for delaying the need for investing in more capacity and for maintaining low prices. The analysis also highlighted the importance that demand management will have in delivering the Governments future work programmes to reduce carbon emissions - we expect that network pricing signals will be even more important in the future when the climate change programme is finalised and the higher costs of re-enforcing distribution networks is signalled.

The objective of WELL's pricing programme is to equitably collect the revenue that it needs to build and operate the network and to signal the future cost of using the network. Practically this means:

- Prices that will recover the cost to build and operate the network;
- Prices that encourage off peak use and discourage peak use;
- Prices that encourage consumers to allow WELL to directly manage demand on the network.

Signalling the cost of network congestion provides consumers with the opportunity to change their energy use behaviour and to reduce their electricity costs by moving their demand to lower congestion periods. This has the immediate benefit of less expensive lines charges (for those who move their energy consumption to off peak periods) and the long term benefits of lower prices through avoiding or delaying network re-enforcement.

Ultimately, we want to move all customers to cost-reflective pricing arrangements that better signal economic costs. The speed and shape of this transition is constrained by factors such as the need to limit price shock (especially for customers who struggle with affordability), to comply with low-user low-fixed charge regulations, and to bring retailers along. In addition, the work to validate the optimal strength of new price signals and changes in cost allocation is a large piece of work and will take time.

Our pricing programme is informed by:

- The cost impact of re-enforcing the distribution network to meet growing demand during peak congestion periods. Signalling the cost of re-enforcing the network will let customers choose to avoid network re-enforcement and have lower long term prices, or to pay more to build a larger network that removes the anticipated restrictions on when energy can be used. The price signal therefore represents a clear price-quality trade-off for consumers;
- The risks (e.g. of congestion and cost of providing higher network capacity) and opportunities (e.g. to reduce network investment pressures) of new and maturing technologies – these increase the value of adopting prices that clearly signal congestion periods and costs of increasing network capacity, which encourages more efficient use of the network;
- The impact that prices changes will have on consumers, especially those in energy hardship. Practically this will likely mean a gradual transition to cost reflect prices over time.
- The Climate Change Commissions Draft Advice work programme;
- The Electricity Authority's work reviewing pricing principles and monitoring activities – this adds impetus to our focus on pricing efficiency;
- The Electricity Pricing Review considered pricing outcomes and frameworks – this supports pricing efficiency, affordability, fairness and points to the phasing out of low-fixed charge restrictions.

4 Progress on the current pricing Roadmap

4.1 Progress update

In 2017 we published our first Pricing Roadmap which outlined how we are developing our prices. Progress against the roadmap is provided in Appendix A. Figure 19 provides a summary of the pricing programmes for each customer group. The figure provides an assessment of the impact that each customer group has on peak demand and the pricing programmes that we have been implementing to reduce that demand. The roadmap initially focused on Electric Vehicle (EV) owners and residential customers as the main contributors to peak demand and therefore the greatest driver for the need to re-enforce the network.

Figure 19 – Summary of progress on the Pricing Roadmap

Prices in development | Prices developed & implemented

Customer group	Impact on peak demand and future price increases	Pricing programmes to signal peak demand						
		2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24
Residential customers	High – main contributor to peak demand		Optional residential TOU			ToU for all residential, EV & battery customers		
EV & battery owners	High – future contributor to peak demand	EV & Battery ToU tariffs				ToU for all residential, EV & battery customers / Managed EV & battery changing tariff		
Small/medium commercial	Currently low, expected to increase to medium with DER aggregation					Cost reflective tariffs to capture new commercial services operating during peak demand periods		
Large commercial	Low – cost reflective prices & contribution policy in place	Refine tariff levels and contribution policy to reflect changes in customer demand						

4.2 EV Charging trial

In late 2017 WELL conducted a trial to better understand the home charging behaviours of EV owners and how they could potentially affect demand for electricity. The trial monitored the operation of 100 EVs and EV chargers and surveyed the vehicle owners about how they preferred to use their vehicles and their thoughts about potential EV services. The results of the trial have helped influence the design of our EV pricing and allowed us to gain an insight into customers' preferences for future EV charging services. The EV trial results can be found at www.welectricity.co.nz/disclosures/pricing/evtrial/. A summary of the key findings is provided in Figure 20.

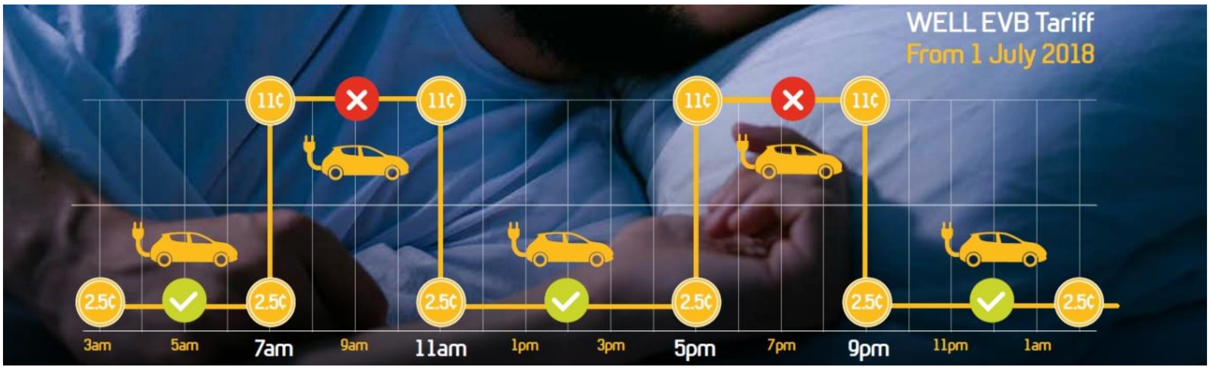
Figure 20 - Summary of the findings of the EV charging trial

Finding	Impact on pricing
EV charging will increase average residential demand by approximately 2,500kWh, equal to 1/4 - 1/3 of annual household electricity consumption.	The electrification of transportation will have a material impact on electricity use. A larger network will need to be built to meet this demand if the demand cannot be shifted to off-peak periods.
70% Drivers were comfortable with an EDB managing their EV charging.	Consumers are likely to be receptive to demand management services at the right price point.
80% of EV owners charge their vehicles after 9pm.	Charging during off-peak, night time periods appear to suit customer preferences – most consumers don't need to charge their vehicles during peak periods.
66% of EV owner's use a timer on their EV charges that lets them chooses when to charge.	Most vehicles have a timer that could be used to respond to ToU price signals. Newer EV's also have the equipment that would allow an EDB to manage when an EV charges.
EV's provide a 45% reduction in household energy costs.	Household costs should reduce with the transition to an EV. This should help to encourage a faster transition to EVs by bringing forward the point that it will be economic to change from the current petrol or diesel vehicle.

4.3 EV and Battery prices

Following the trial, WELL introduced new prices in July 2018 for households with EVs and batteries that reflected the benefits of charging their vehicles or batteries during less congested periods. For simplicity, the tariff applied to energy use for the entire household. Figure 21 - shows pictorially the higher prices for energy use during congested periods and the lower prices for less congested periods.

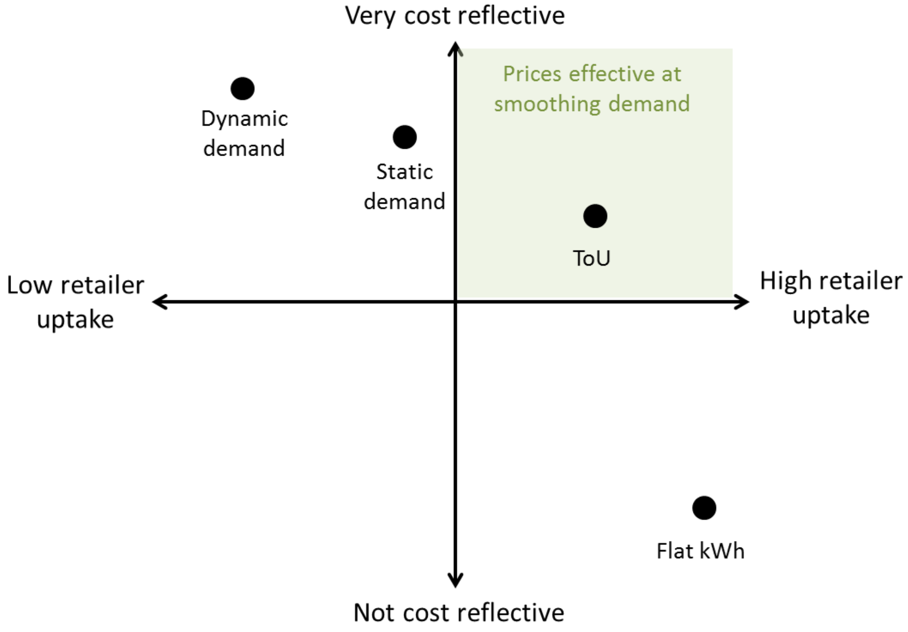
Figure 21 – WELLs 2018 EV and Battery prices



Initially we proposed to apply a peak demand price which we considered a more cost reflective pricing method than other pricing methodologies. However, following retailer feedback, we settled on ToU prices. Retailer billing systems were not able to provide the billing data needed to calculate demand prices. A critical lesson is that trade-offs will have to be made between how cost reflective prices are (how good prices are at signally congestion) and whether prices are understood and can be practically applied. While more complex pricing methods like demand based pricing provide good theoretical price signal of congestion, they are less likely to be passed through to consumers by retailers as they are difficult to implement and manage, and much harder for consumers to understand.

If prices are not passed through to consumers, they will be ineffective at achieving the purpose of efficient prices – to inform consumer's choices about when to use electricity. The graph below illustrates this trade-off. While ToU prices may not be the best at signalling congestion, retailers are more likely to pass prices onto consumers and therefore ToU is the most effective pricing method for encouraging consumers to use off-peak energy and smoothing congestion.

Figure 22 – trade-off between cost reflectivity and practical application



It is important to note that this assessment is for a point in time and that retailer billing systems will evolve, technology will assist consumers in choosing different pricing options and consumers will become more educated about their pricing choices. We do expect more cost reflective pricing options will become viable in the future.

4.4 ToU residential prices

For the reasons outlined in the previous section, we favour ToU pricing aligned with the emerging industry standard design for mass market consumers.

- WELL introduced optional residential ToU prices in 2020. Residential ToU prices were offered as a pricing option (rather than applying ToU to all residential consumers) following retailer feedback that more time was needed to develop and change internal processes and to consider how to practically apply the new prices. Approximately 12% or 18,000 residential consumers were voluntarily shifted to ToU prices.
- WELL applied ToU prices from 1 April 2021 to all residential consumers after consulting with retailers. Retailers provided constructive feedback which included learnings and suggestions from the application of ToU by other distribution networks in 2020.

4.4.1 Residential ToU Pricing Structure

Our residential ToU pricing structure reflects demand patterns *and* aligns with other network distribution ToU structures. Aligning pricing structures with other networks will help minimise implementation costs for retailers. Our ToU pricing structure is summarised in Figure 23.

Figure 23 – ToU price structure

Design parameter	Industry standard?	Approach	Comment
Hourly Pattern	Y	AM peak = 7 to 11 PM peak = 5 to 9 No shoulder	A shoulder period has not been included as consumers changing their 'discretionary' load are most likely to do this using timers on appliances (e.g. EV charging, or dishwashers) and are unlikely to discriminate between a peak and shoulder. In addition, a daytime shoulder will over-signal the value of midday solar production.
Weekly Pattern	Y	No peak periods on weekends	Low-cost weekend concept is relatively simple for consumers to understand and adjust to.
Seasonal Pattern	Y	Consistent signals year-round	Seasonal pattern adds complexity (for supply chain and consumers) and exacerbates winter energy hardship for vulnerable consumers facing budgeting challenges.

Figure 24 below illustrates the residential ToU pricing structure.

Figure 24 – Residential ToU pricing structure

Figure 25 illustrates the ToU structures being offered by different distribution networks. WELL's ToU structure aligns with the five other networks serving the majority of the New Zealand residential consumer market. It is also consistent with our existing EV and battery pricing structures and with the structure the Electricity Network Association are proposing to include in its 'pricing menu'[11].

[11] The pricing menu proposes a set of standard pricing structures designed to align distribution prices.

Figure 25 – ToU structures aligned with WELL's residential ToU prices[12]

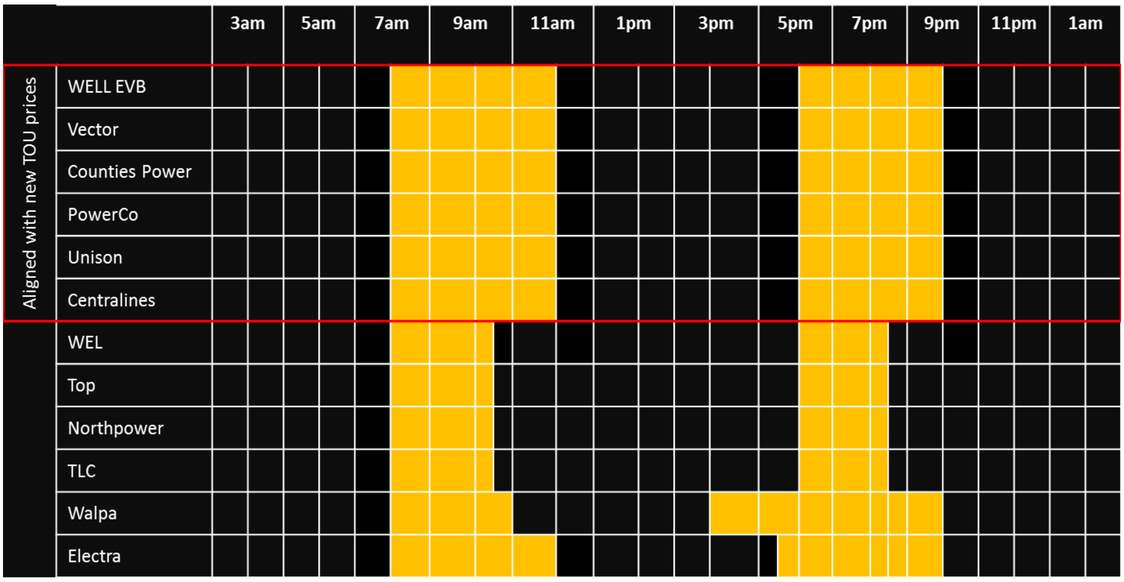
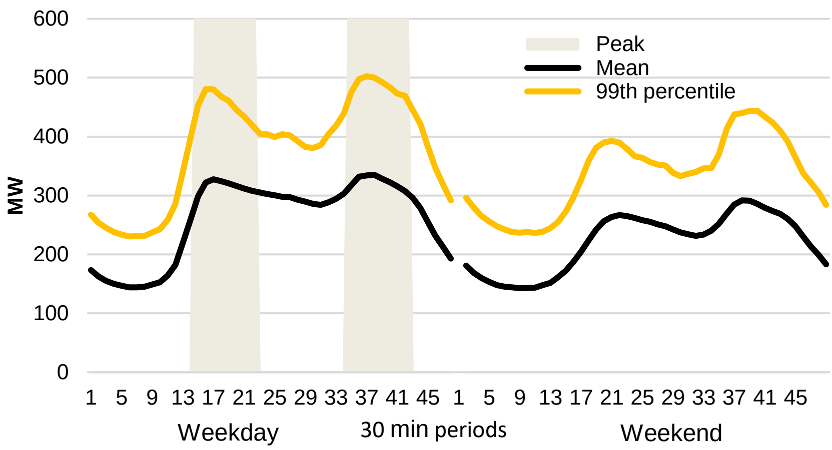


Figure 26 compares the standard time periods against demand patterns on our network. The residential ToU structure is a good match to the Wellington region's demand patterns.

Figure 26 – Illustrating the peak pricing period's alignment with peak demand



ToU unit rates have been designed so that the pricing signals are consistent with WELL's existing prices and its unit rates for ripple control. A common fixed charge has been used for all residential consumers, with the exception of the low fixed charge restrictions which WELL will continue to apply in accordance with the applicable rules, noting that the current low fixed user restrictions are expected to change as a result of the Electricity Price Review recommendations.

ToU prices will not be applied to dedicated control prices as dedicated control prices are already low to reflect that this tariff provides WELL with the ability to move the supply of energy during peak demand periods.

12 The assessment against other network process was based on 1 April 2019 prices.

4.4.2 Gradual uptake

The retailer consultation highlighted that not all retailers will be able to provide billing data in the 30 minute increments needed to calculate ToU data. The key reasons for Traders not being able to provide the half hour time sliced data needed to calculate ToU prices were (ranked from the largest to smallest in impact):

1. **Retailer billing systems and validation processes can't process half hour data needed for pricing:** Some Trader billing systems can't process all of the half hour data needed to calculate ToU prices. Other Traders' data validation processes have been designed for the market settlement process and not for distribution billing.

2. **Data agreements not in place with meter providers**: A Retailer will have a data agreement in place with meter providers for the provision of the half hour data. The agreement also ensures that the data is provided to the correct level of quality. Some Retailers are still negotiating terms and do not have data agreements in place. Feedback indicated that negotiations are difficult because Retailers have little influence over agreement terms. Terms include providing data that meets the required quality levels.

3. **Legacy meters or no communications**: Some ICPs do not have AMI meters that can provide half hour data needed to calculate ToU prices. Some meters are also not able to communicate the data.

4. **Incorrect registry flags:** The electricity registry comms flag can incorrectly show the meter is communicating when it is not. It takes up to 90 days to correct any errors. Feedback also suggested that there are weak incentives for meter providers to correct any errors so it could take longer than 90 days for corrections to be made.

5. **Intermittent communications or failed communications:** The communication status of a meter can change over time. If communications stop there will be a minimum of 90 days before the registry flag is adjusted and the ICP will be eligible for the 'opt out' price. Reasons for communications stopping include new buildings and physical obstructions, cell phone interference, reduced mesh density and meter box damage.

We have made a number of pricing structure changes to help manage the range of Trader specific issues and to encourage Retailers to correct any errors and to upgrade their own systems and processes so that ToU can be applied. Feedback indicates that about 40% of residential consumers (depending on how fast Traders can upgrade their billing systems) will not be able to apply ToU prices come 1 April 2021. Retailers are in the process of upgrading billing systems and continue to negotiate data agreements with Meter Providers. They have indicated that there are always likely to be legacy meters and meters with no communication, resulting in 10-15% of ICPs on our network where cost reflective prices can't be applied.

4.4.3 Customer impact of the annual price increase

WELL is cognisant of the potential impact ToU prices might have on those in energy hardship and the on-going economic impacts of Covid-19. As part of developing ToU prices, a sample data set representing over 10% of WELL's residential consumers was used to understand the customer impact of applying ToU prices. Household deprivation data was combined with the consumption data to analyse impacts on affordability.

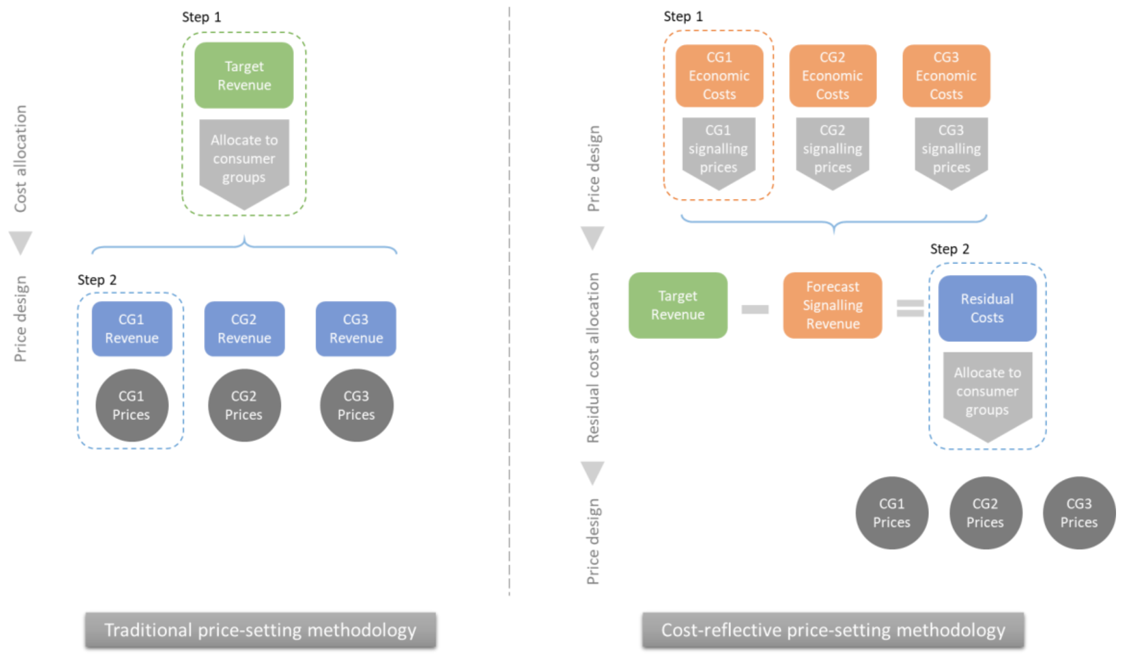
5 New work programmes

We have made good progress against the original Pricing Roadmap actions and we have advanced our own thinking on how to better manage electricity demand. The increases in demand that are likely to result from the climate change initiatives will make it even more important for networks to move energy use to less congested periods. The Authority have also refreshed their pricing methodology and the Electricity Pricing Review has recommended a number of changes that directly impact pricing. These changes have led to a number of new work programmes that include a pricing element.

5.1 Applying the cost reflective price setting methodology

In 2019 the Authority released a revised pricing methodology. We have used the implementation of the new methodology as an opportunity also review our existing price structures. This work programme also includes the last steps of the previous roadmap, specifically considering whether to move the last customer group, small commercial consumers, to cost reflective prices. Figure 27 illustrates our current price-setting methodology and the revised methodology which we are transitioning too.

Figure 27 - Cost reflective cots setting methodology



5.1.1 Step one – setting price signals

The first step of the 'cost reflective' price setting methodology is to design price signals that reflect the future cost of the network. We will do this by calculating the long run marginal cost (LRMC). For the foreseeable future, distribution pricing is best suited to signalling the enduring (or slow-moving) economic cost – i.e. LRMC rather than transient operational costs (short run marginal cost). Currently, distribution pricing flows through a retail market using an annual price-setting process. The industry preference is to use market wide tariffs for the mass market) and there is limited capacity for complex, customised prices. Most customers have low engagement in electricity pricing and pay little attention to the distribution component of their power bill. Consumers may consider prices for the occasional investment decision (e.g. appliance purchases) but give little consideration to day-by-day consumption decisions.

There may be a time in the future when our prices will need to change in real time to more accurately reflect changes in the future cost of using the network. However, the industry does not have the capacity to implement real time prices and consumers are not yet in a position to use the price signals in their everyday decisions about electricity use.

We will also consider whether to break prices into geographic pricing zones if there are differences in the LRMC. The final decision will take into consideration the trade-offs in complexity (thereby increasing network and retail operating costs) and the risk of reducing retail competition.

5.1.1.1 Selecting a pricing method

Once we have calculated the strength of the price signal, we will then select a pricing method to apply that signal.

Small consumers

Time-of-use (ToU) is the best-fit for now for smaller consumers. As discussed earlier, ToU is effective because it:

- is readily understood – it doesn't require consumers to understand a new usage statistic (e.g. peak demand) – and doesn't expose consumers to excessive volatility or risk
- can be implemented by most NZ retailers, helped along by its emerging prevalence amongst larger distributors
- sends an efficient signal and effective signal for the types of decisions small consumers make
- operates with existing commercial cycles (annual rate setting, monthly billing)

Longer-term, successors to ToU may be appropriate, for example if:

- daily load profiles flatten enough that investment is driven by peak days rather than peak hours
- there are enough responsive demands (or injections) in a typical household to support more dynamic signalling
- retail (or aggregator) capability is no longer an impediment

However, more dynamic pricing (such as coincident peak demand) comes with significant implementation challenges and risk of repeated bill shocks.

Controllability discounts

A central pricing strategy is to develop new services to assist us in managing congestion. This includes developing a managed charging service for EVs and other appliances. The new services will include pricing discounts or incentives for "appliances" that can be controlled to further manage network load. This is well established for hot water heating – a storage load that can be managed with minimal customer impact.

Large users

Large users are more responsive to price signals and have the technology and knowledge to change their energy behavior in response to more complex price signals. We will consider more cost reflective pricing methods like coincident maximum demand charges for usage during actual network peaks, rather than pre-defined peak periods.

5.1.2 Step two – recovering the residual revenue not covered by price signals

After designing cost-signalling prices, there will be a residual amount left to recover. Ideally, the residual is:

- recovered through prices that do not influence behaviour
- allocated between customer groups using a simple metric
- tested to ensure total revenue from each customer group is with subsidy-free range

We have partial picture of subsidy-free range at present – the range between avoidable operating costs and the cost of a standalone non-network solution. We are considering calculating a subsidy free range based on total avoidable cost, and standalone network cost to provide a more realistic picture.

5.1.3 Implementation

We will be reviewing our price structures this regulatory year. This will include a quantitative analysis of each price option, including setting out provisional estimates around charge levels for different approaches, and bill impacts for different consumer groups under different approaches. An assessment of different pricing options will include:

- consistency with EA pricing principle
- economic efficiency
- fit with network context
- consumer impact, and
- implementation considerations

The review of prices may highlight that large changes are needed and that some customers may be impacted by price increases. We will consider a transition path to will smooth any price shocks. The work programme has been included in the refreshed Pricing Roadmap.

5.2 Services to manage congestion

A key component of our pricing strategy is to develop services that will assist us in managing congestion. WELL has trialled new technology that allows WELL to manage EV and battery charging during the peak demand periods. The new service will ensure EV owners vehicles are charged when they are needed and will provide WELL with the ability to manage EV charging within the networks capacity. WELL will offer the service for a lower price than standard distribution prices. This allows a real time ability to stabilise the LV network by having visibility of consumer charging behaviour and modulating the charge rate based on network capacity and supply quality at that point in time. WELL is trialling the DeX software that connects consumer devices, monitors network capacity and performance and manages the charging of EV's and batteries within the performance limits of the network.

5.3 Roadmap of changes needed to accommodate EVs on distribution networks

EV Connect is an stakeholder wide work programme that focuses on how more energy can be delivered through the existing network. The purpose of doing this is to support EV adoption while maintaining network security. One of the outcomes of the programme is, by May 2021, to deliver and consult with industry on a roadmap of the actions needed for distributions networks to accommodate the uptake of EV's.

While attention is specifically on EVs under this project, there are clear implications and relevance to wider categories of distributed energy resources (**DER**) like solar PV, batteries, hot water systems and other appliances. This was brought strongly to light through consultations with stakeholders who often noted that an initiative or approach that could apply to EVs or EV charging assets could also extend to or from arrangements for other types of DER. The December 2020 industry consultation phase provided the foundation components of the Roadmap. Feedback was gathered via a half day workshop with 50 stakeholder held on 20 October 2020 and via 13 written submissions received following the workshop.

A summary of stakeholder feedback is provided on our website at https://www.welectricity.co.nz/about-us/major-projects/ev-connect/. We have used stakeholder feedback as the bases of a draft roadmap – the items where feedback was in consensus formed the foundations of the roadmap. A copy of the draft Roadmap and a description of the roadmap works streams is also provided on our website at https://www.welectricity.co.nz/about-us/major-projects/ev-connect/.

Pricing plays an important part to many of the work streams. EV Connect work streams that have price elements include:

1. **Distribution network demand management**: EDBs would need to be able to ensure that EVs charge during off-peak periods – this would enable EDBs to meet the emission budgets at an affordable price and within the Commissions timeframes. To do this, EDBs will need to develop a demand management capability to encourage energy use outside of peaks demand periods. The new service would be offered with a price incentive. The work stream also includes education and technology to assist consumers in making choices about how they use electricity.
2. **Distribution Systems Operator (DSO):** Energy stored in DERs like EV batteries provides a valuable resource for distribution demand management. It could also provide a useful energy resource for other users. This work stream considers whether a market is needed for consumers to recognise the full value that letting other parties use their DERs could provide them. This would include calculating real time prices that accurately reflects the changing value of the stored energy.

5.4 Developing a long term investment plan

Managing demand to better utilise the existing network is expected to provide a large proportion of the additional demand needed to deliver the Governments emissions budgets. However, more capacity will need to be built in some areas where the increase in demand exceeds or is close to network capacity during non-congested periods. Our analysis of the cost impact of the Climate Change initiatives is very high level and does not have the detail needed to calculate future prices or price signals. WELL is developing a long term investment programme, beyond the 10 year regulatory planning period, that includes the climate change initiatives. From a pricing perspective, the long term investment plan will confirm the investment needed to deliver the Governments Climate Change Initiatives. This will inform the LRMC calculation and our price signals.

6 Refreshed Pricing Roadmap (excluding EV Connect Roadmap actions)

Regulatory year	2021/22	2022/23	2023/24	2024/25
Long term investment programme	• Calculate an initial view of the Climate Change investment requirements • Inform LRMC	• Refine long term investment programme with final climate change initiatives • Review LRMC and adjust the pricing transition path if necessary		
Peak demand price signals	• Review LRMC for customer groups • Consider geographic pricing zones if different parts of the network have enduring significant differences in LRMC • Review ToU peak price signals for residential and calculate price signals for small commercial consumers • Review pricing methods for large commercial consumers • Review price signals for large commercial consumers	• Consult on new small commercial cost reflective prices • Consult on any changes to existing price structures		• Regular review price structures – confirm they are fit for purpose
Controllability discounts	• Select options for applying discounts/incentives for new controllable load - for both residential and commercial consumers • Review price signals for hot water control, managed services • Consistent with peak demand signals	• Consult of new prices for managed services	• Add new prices as new managed services are developed as part of EV Connect	• Add new prices as new managed services are developed
Subsidy free residential	• Select pricing method to apply fixed prices • Select allocation methods and consumer grouping approaches • Calculate fixed prices • Calculate total avoidable cost, and standalone network cost • Tested to ensure total revenue from each customer group is with subsidy-free range	• Consult on any changes to existing price structures		• Regular review price structures – confirm they are fit for purpose
Transition	• Compare refreshed prices to current tariffs • Develop a transition path that will manage price shocks • Highlight other industry changes that that could accelerate or delay the transition – including the exit of LFC restrictions, price path updates and Transpower's new pricing	• **Continuously refine the transition plan** • **Transition to new price structure**		
Consumer education	• Educate customers on how to save money on distribution charges by managing usage and shifting load to off-peak periods. • Consider eco-bulb/energy saving programme to offset future price changes	• Promote new managed service with retailers and consumers	•	•
Transmission prices		• Develop prices to pass through Transpower prices • Consult on any changes to existing price structures	• Apply new prices	•
Exiting LFC	• Develop transition plan • Consult with retailers	• **Apply transition plan**		

7 Appendix 1: Progress against the current Pricing Roadmap

Initiate pricing reform (April 2017 – March 2018)		Develop detailed plans for pricing reform (April 2018 – March 2020)		Manage roll-out of future pricing (April 2020 – March 2025)	
Initiative	Progress	Initiative	Progress	Initiative	Progress
Identify overall objectives for pricing reform and update strategy and plan.	✓ Completed ✓ Updated for phase 2	Work with ENA and other distributors to ensure alignment of proposed price structures.	✓ Industry standard for residential customers developed	Implement new price structures and prices (under revenue cap).	✓ Large commercial cost reflective already in place ✓ Residential ToU prices implemented ● Developing small commercial cost reflective ● Developing managed EV and battery charging prices
Determine preferred future price structures, e.g. ToU and/or demand and/or capacity.			✓ Residential ToU + DER management price ● Small commercial structures delayed pending outcomes of electricity price review (include re-proportioning costs between commercial and residential).	Transition customers from old to new price structures.	✓ Transitioning all residential ToU in 2021
Consult with stakeholders on future pricing structures.	✓ Completed for EV trial	Further consult with stakeholders to explain preferred pricing structures and to educate them about upcoming pricing changes.	✓ Industry review panels ✓ Retailer residential ToU consultation complete	Further consult with stakeholders. Educate customers on how to save money on distribution charges by managing usage and shifting load to off-peak periods.	✓ Energy Mate programme ● Developing on-line education tools ● Consider other resources
High level scoping of metering, data and billing constraints/issues.	✓ Competed – industry review	Develop plan for remediation of metering / billing / data issues.	✓ Billing system tested for ToU rollout ● New billing systems requirements being developed – delayed to align with IT strategy	Resolve implementation issues.	● Considering new billing capability to process and analysis 30 min data.
Gather data for analytics.	✓ Completed for EV trial ✓ High level industry study ✓ Still to get for WELL network	Seek funding from Commerce Commission for required changes to billing systems. Work with 3rd parties (retailers, MSP) to resolve metering and data issues.	✓ Funding needs included in DPP capex ✓ Access to meter data now part of Code – consider most appropriate data source	Ongoing review of progress towards achieving pricing objectives.	● Plan to be developed. This will consider cost reflective small commercial prices and future cost reflective structures available once LFC restrictions removed.
Introduce trial demand charge for residential EV customers.	✓ Completed	Detailed modelling of new pricing structures and prices, including likely impacts on customers. Customer trials if required.	✓ High level industry analysis completed ✓ Customer impacts of residential ToU analysed		
		Check of regulatory compliance	✓ New residential ToU prices comply with low fixed user restrictions		
		Separate pricing categories for EV residential customers and update of demand charge from $0.00/kW/month.	n/a Considering combining EV ToU with residential ToU ✓ Demand pricing replaced with ToU		
		Agree with EA/Retailers how retailers will pass through distribution price signals to end customers.	✓ Consulted with retailers – majority suggested they would pass price signal through in some form.		