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Powerful potential

New Zealand’s vehicle-to-grid opportunity

25 September 2025

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We have been providing useful, high-quality advice and analysis for over 25 years. Our roots are in the electricity sector and our practice has grown from there. We have developed deep expertise across the wider energy sector, and in environmental and resource economics. We have also translated our skills to assignments in telecommunications and water infrastructure.

Our directors have held senior executive roles in the energy and telecommunications sectors, and our team has a breadth of policy, regulatory, economic analysis, strategy, modelling, forecasting and reporting expertise. Our clients include large users, suppliers, regulators and governments. Our practical experience and range of skills means we can tackle difficult problems and provide advice you can use.

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About Retyna

Retyna is a specialist transport electrification consultancy, founded in 2018, delivering advice, project design and implementation for a variety of clients, from start-ups to NZX-listed companies and government departments, both in New Zealand and internationally. Our knowledge and experience covers electrification of all transport modes and associated charging infrastructure, with a particular focus on heavy vehicles and the marine sector.

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Contents

Executive summary

Transportation is electrifying at pace in New Zealand and around the world – driven by falling battery costs, improving performance and a proliferation of increasingly attractive electric vehicle (EV) options.

Land transport electrification will transform energy demand in New Zealand – with the potential to replace around 190 PJ of imported liquid fuels per year with around 49 PJ of domestically produced electricity. At today's costs, this amounts to a fuel cost saving on the order of $2.9 billion per year.

Managed poorly, fuel cost savings could be undermined by the cost of operating a less efficient power system with higher peak demand and correspondingly higher capacity costs.

However, an EV is a battery on wheels – a uniquely flexible and capable energy device.

With smart charging, EVs need not add to peak demand at all in most cases. In this world, EVs improve the efficiency of the power system – enabling more energy to be supplied for each unit of system capacity.

Going beyond smart charging, EVs have the potential to supply energy – providing their owners with a portable or backup power supply to appliances that aren't connected to a house that's connected to the grid (vehicle-to-load or V2L) or injecting power back into a grid-connected property or the power system (vehicle-to-grid or V2G).

V2G is technically feasible and economically valuable.

For light vehicles, we estimate an economic value from V2G (ie, injecting power to either premises or grid) of up to $2,000 per car per year. For heavy vehicles, we estimate an economic value of up to $10,000 per truck per year in most cases and up to $25,000 in some cases.

This value is dynamic and will change over time – most notably if stationary batteries at premises, or distributed through electricity networks, step into the same role.

However, V2G clearly presents a valuable opportunity – for the electricity sector to reduce its cost profile, for the vehicle sector to sweeten the EV value proposition, for vehicle owners to reduce their cost of ownership, and for the country as a whole to achieve a more efficient and productive energy supply.

On the flip side, unmanaged or poorly coordinated V2G could increase costs and compromise safe and secure operation of the power system.

Realising the opportunities and managing the risk will require coordination and innovation at multiple levels.

Vehicle owners and operators need:

- awareness and decision-support
- consumer-friendly packaging that makes V2G enrolment and participation accessible and attractive
- a payoff that makes V2G participation worthwhile

At a technical level, we need:

- compatibility of in-vehicle and charger capabilities
- interoperable communications and control systems, and
- (as penetration grows) integration with power system operations

The major value opportunities for V2G are reducing generation costs and distribution network costs, with some additional value from reducing transmission costs and having a backup power source during network outages. The last of these provides direct consumer benefit, the others benefit consumers more broadly by reducing the cost of electricity supply in New Zealand.

The best and most important way to incentivise and reward productive use of V2G is with cost-reflective pricing.

We already have this in place for generation costs through the wholesale market, meaning retailers can offer sharper pricing for properties with managed V2G.

To spur V2G uptake, it needs to be complemented with cost-reflective distribution network pricing. Unfortunately, time-of-use pricing (with or without payments for injection) does not work for V2G at scale. This is because V2G is too flexible and responsive for that type of pricing.

The best solution is to supplement time of use pricing with *type* of use ('TYoU') pricing – ie, discounted charges for EV usage if it is set up with suitable remote management arrangements.

A consistent nationwide approach to type of use charging, designed to support contestability and to maximise residual controllability, would be the best way to spur V2G uptake.

In time, this will provide a platform of enrolled resources that can be paid to provide 'deeper' response for more acute network deferral opportunities.

This same approach is also suitable for the other key flexible resource – next-generation hot-water control – as well as for stationary batteries.

As penetration grows, the scope and scale of distribution network monitoring and operational coordination needs will increase. As penetration grows further, it will also drive an increase in information sharing needs from distributors to Transpower.

Eventually, it may also become useful to develop flexibility trading arrangements. However at this time such arrangements are not needed to unlock the most material benefits of V2G. It is important that effort on progressing flexible trading arrangements doesn't distract from the more urgent need to develop nationally consistent type of use distribution pricing.

The value on offer provides a strong motivation to get this right.

1 Introduction

This report focusses on vehicle-to-grid ('V2G') in New Zealand – its potential benefits and the success factors needed to realise these benefits.

We use the term V2G to refer to grid-synchronised export from electric vehicle batteries back to a property or to the local distribution or transmission network.

The report was sponsored and funded by electricity and transport sector participants (details at the end of this section) and carried out by Concept Consulting (Concept) and Retyna in 2025. Concept and Retyna thank the sponsors for their support and their invaluable input. Concept and Retyna have editorial control of the report, so the research, analysis and conclusions are our own and may not represent the views of all sponsors.

V2G is an important topic for a range of parties with differing backgrounds. We have endeavoured to make this report accessible to a wide, albeit technical, audience. To assist with this, we have distilled our key observations into the main body of the report and relegated more in-depth or specialist analysis to technical appendices.

The report starts with analysis of the potential value of V2G – including the basis for our headline figures of $2,000, $10,000 and $25,000 per vehicle per year – and the risks associated with failing to manage EV growth. This makes clear the motivation, from a public policy perspective, for getting EV charging and V2G right.

Next, we consider V2G from a consumer perspective. Without an attractive service offering, there is no prospect of V2G realising its potential. Understanding consumer perspectives is of fundamental importance to successfully reforming and evolving industry arrangements.

Then, we consider technical requirements. Successful V2G needs to integrate vehicle and charger capabilities, communications, and power system operation. These are the 'under-the-hood' foundations that enable safe and reliable access to V2G.

Finally, we consider commercial arrangements. These provide the glue that enables resources to be put to their best use and supports their availability in the first place.

Because a lot of the issues relating to V2G are highly technical, we have tried to keep the main body of the report accessible to readers who are not versed in the minutiae of electricity system operations or vehicle charger design, instead trying to succinctly draw out the key insights. However, because the technical issues are important, we have set these out in a set of appendices that mirror the body of the report:

- Appendix A covers the V2G value opportunity and provides more detail the modelling supporting our analysis
- Appendix B provides more discussion on consumer choice
- Appendix C provides more discussion on technical standards
- Appendix D addresses commercial arrangements and includes more of our modelling work
- Appendix E summarises insights from V2G trials in New Zealand and abroad.

Sponsoring organisations (listed in alphabetical order).

	AA Research Foundation. The AA is one of New Zealand's largest membership organisations, supporting 1.1 million Personal Members and over 1 million Business Vehicles. The Research Foundation funds research into road safety and sustainable mobility. www.aa.co.nz
	Aurora Energy is the electricity distribution business supplying over 200,000 people across Ōtākou in Ōtepoti Dunedin, Central Otago, Wānaka and Tāhuna Queenstown. www.auroraenergy.co.nz
	Ecotricity is NZ's first, and only, Toitū climate positive certified electricity retailer. Ecotricity is owned by Genesis – an energy generator and retailer supplying electricity, natural gas, and LPG to more than 520,000 customers in New Zealand. Genesis also owns ChargeNet - one of New Zealand's largest public EV charging service providers. www.ecotricity.co.nz
	EECA. The Energy Efficiency and Conservation Authority is a Crown Agency who undertakes research, provides targeted investment and support, and regulates energy-related products, processes and systems to help New Zealand achieve a sustainable energy system that supports the prosperity and wellbeing of current and future generations. www.eeca.co.nz

	Fonterra is a farmer-owned dairy cooperative that processes, markets, and exports milk and milk products. It has one of New Zealand's largest fleet of trucks, used for collecting milk from farms across the country. www.fonterra.com
	Horizon Networks owns, manages and operates the electricity network that supplies more than 25,500 customers in the Eastern Bay of Plenty region. www.horizonnetworks.nz
	Meridian Energy is an energy generator and retailer, generating electricity entirely from renewable sources. Meridian has developed a network of public EV charging stations. www.meridianenergy.co.nz
	MinterEllisonRuddWatts is one of New Zealand's leading law firms. Among their many practice areas, they have been heavily involved in the electricity sector, including arrangements relating to EV charging. www.minterellison.co.nz
	Orion owns and operates the electricity distribution network providing power to more than 228,000 homes and businesses in central Waitaha Canterbury. www.oriongroup.co.nz
	Powerco is an electricity and gas distribution business, supplying energy to over 900,000 customers. Their electricity networks cover the largest geographical footprint of any distributor in New Zealand. www.powerco.co.nz

Star Charge	***StarCharge*** is a global leader in electric vehicle supply equipment (EVSE), delivering advanced charging infrastructure and pioneering V2G solutions for both residential and commercial applications. With a strong track record of large-scale deployments and innovation, StarCharge is recognised as a leading global supplier driving the transition to smarter, more sustainable energy and mobility solutions. www.starcharge.com
TRANSPOWER	***Transpower*** owns and operates New Zealand's national electricity transmission network, and is also the System Operator of New Zealand's wholesale electricity market. www.transpower.co.nz
unison	***Unison Networks*** owns and operates the electricity network that supplies electricity to around 119,000 customers in the Hawke's Bay, Taupo and Rotorua. www.unison.co.nz
WEL Networks	WEL Networks owns and operates the electricity network that supplies electricity to around 102,000 customers across the Waikato region. www.wel.co.nz

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2 There is a significant opportunity

EVs are coming of age, largely due to advances in battery technology and costs. They are moving into becoming a mainstream vehicle choice, offering increasingly attractive cost and performance for a growing share of vehicle buyers, making up 13% of new vehicle registrations in 2025.

The up-front (capital) cost of buying an EV is a key deterrent for consumers for now, but costs are falling and will get closer to parity over time.

In contrast, the ‘fuel’ cost of EVs is already much lower than a petrol or diesel vehicle. This means that, even today, EVs offer a lower total cost of ownership than petrol or diesel vehicles for many consumers.

New Zealand currently imports around 190 PJ of liquid fuels for land transport each year, at a cost of around $4.4 billion. Given that a fully electric land transport fleet would consume approximately one-quarter of the primary energy as a fossil-fuelled fleet, this could be replaced by around 49 PJ of electricity generation – or just over 20 TWh. The levelised cost of new renewable energy is around $100 per MWh, so this translates to a fuel cost of around $1.5 billion.

On this simple analysis, transport electrification has the potential to replace $4.4 billion of annual fuel imports with $1.5 billion of domestically produced renewable electricity – a saving of $2.9 billion a year.

Of course, there are also costs associated with getting either fuel to the vehicles.

For liquid fuels, this involves international supply chains feeding a web of domestic shipping, handling, storage, trucking and retail infrastructure with a mix of sunk and ongoing costs. Much of this infrastructure and activity will become redundant over time, presenting transition challenges that are outside the scope of this report.

In the long run, electrification will enable us to rationalise our domestic energy infrastructure – with greater use of electricity networks eventually removing the need to maintain separate liquid fuel and natural gas networks.

For electricity, we already have infrastructure in place for moving energy around the country and to most homes and businesses. We will need some new public charging infrastructure, but most charging is likely to take place at homes, businesses and depots that already have electricity supplies.

This near universal coverage of electricity infrastructure is a key enabler of rapid electrification. However, the cost of electrifying will heavily depend on how well we use the capacity of our electricity system.

2.1 EV charging and injection

Managed poorly, EVs could severely worsen the productivity of the electricity system – adding to demand during peak periods and driving a need for more firming generation, and transmission and distribution capacity.

Fortunately, EVs have the potential to do the reverse – to improve electricity supply by enhancing:

- network efficiency – that is, improving the amount of energy supplied per unit of network capacity
- generation efficiency – aligning demand with periods of high renewable supply reduces the need for ‘firming’ capacity and reduces the cost per unit of delivered energy.

This is possible because, for most vehicles most of the time, charging is not highly time-critical.

For example, an EV plugged into a standard household power socket only needs 4.5 hours of charging to replenish the energy used to drive around 50 km. Since most cars travel less than 50 km each day (and even modest EVs have a range many times this distance), charging can usually be interrupted without user impact.

There are two ways to achieve an outcome of minimising the impact of EV charging on capacity costs:

1. passive – owners can simply charge their vehicles off peak. In most areas, this means avoiding winter evenings. Cars and chargers can be set up to prefer off peak time slots, or drivers can simply delay plugging in or turning on
2. active – vehicles or chargers can be paused (or throttled) dynamically at times of network or generation stress. We refer to this as 'smart' charging.

With smart charging, EVs need not add to peak demand at all in most cases – ie, aside from the portion of charging that is truly time-critical (such as at public charge points, some fleet depots, and some households or businesses on some days).

With smart charging, EVs can improve the efficiency and productivity of the power system by flattening out capacity demand peaks, and weighting consumption towards times of surplus generation.

Going beyond smart charging, EVs have the potential to supply energy. There are three tiers of sophistication for sourcing energy from an EV. With reference to the labels that are frequently applied to each tier, these are:

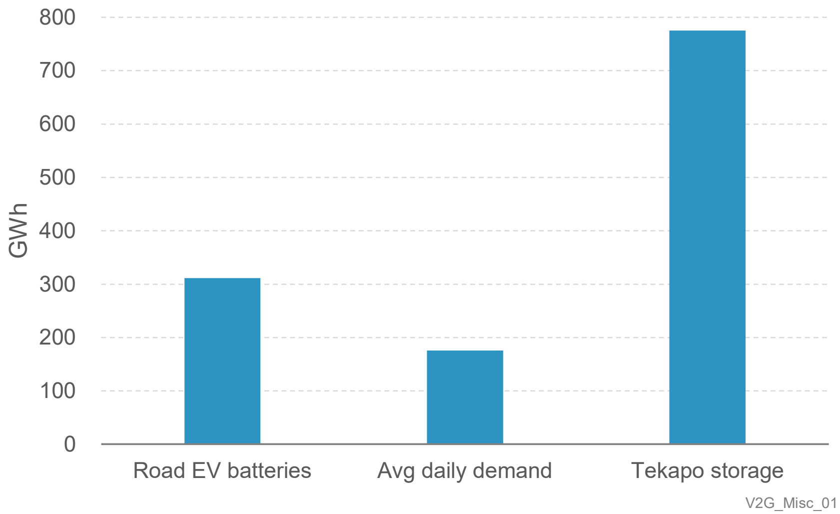
1. vehicle-to-load (V2L) – many EVs can, with or without an adapter, be used to power appliances that aren't connected to the power network. This provides a portable power source (eg, for camping or unpowered work sites) and a simple backup power supply (eg, for charging phones or keeping a freezer cold during a power outage)
2. vehicle-to-premises (V2P)[1] – an EV can be connected to a building that is connected to the grid but injecting to a level that never exceeds the property's demand for electricity. As a supplementary power supply, this can reduce grid demand from a property at peak times – ie, enabling EVs to *reduce* peak demand
3. vehicle-to-grid (V2G) – going one step further, an EV can supply more than the total load at a property so that the property injects energy back into the power system.

V2L has no impact on grid capacity demand but does provide some flexibility and distributed resilience that can soften the impact of supply interruptions. This is an additional selling point for EVs. and may eventually have implications for grid reliability and resilience standards but is not a focus in this paper.

To give an idea of the scale of EV battery energy storage, Figure 1 compares projected storage potential of EV batteries in 2050 (based on the level of EV uptake indicated in Figure 2) with projected average daily demand in 2050, and the storage capacity of Lake Tekapo (one of New Zealand's main hydro storage reservoirs).

[1] We use V2P as a catch-all label for vehicle-to-home (V2H) and vehicle-to-building/business (V2B) which are sometimes used as labels for EVs supplying power to residential households and commercial buildings, respectively, to levels that don't exceed the property's demand.

Figure 1: EV battery storage potential is large



The balance of this report focusses on V2P and V2G. Although there are some differences between the two, these are largely differences in degree rather than being fundamental differences:

- they have most of the same requirements in terms of standards, and systems and processes for coordination
- the value benefits are fundamentally based on the same generation and network value stacks – albeit to different levels.

The main difference is that V2P involves more at-premises coordination that in turn avoids some of the power system coordination challenges associated with injecting back into the grid to levels that could exceed network capacity limits.

Because V2P and V2G are largely the same in terms of the issues associated with their implementation, for the balance of this report we use 'V2G' as a catch-all to cover both situations.

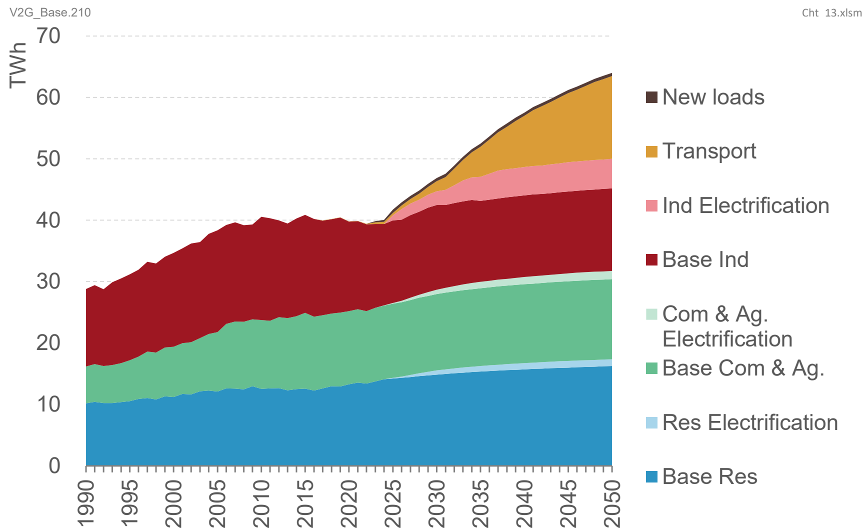
2.2 Electricity system value

Concept maintains electricity demand growth forecasts informed by analysis of underlying drivers and tested against public domain forecasts by other parties.

Like other analysts, and like other countries, we expect transport electrification to make a significant contribution to electricity demand growth over the coming three decades.

Figure 2 shows our base case forecast, which projects a 60% increase in electricity demand by 2050 approximately half of which is due to road transport electrification.

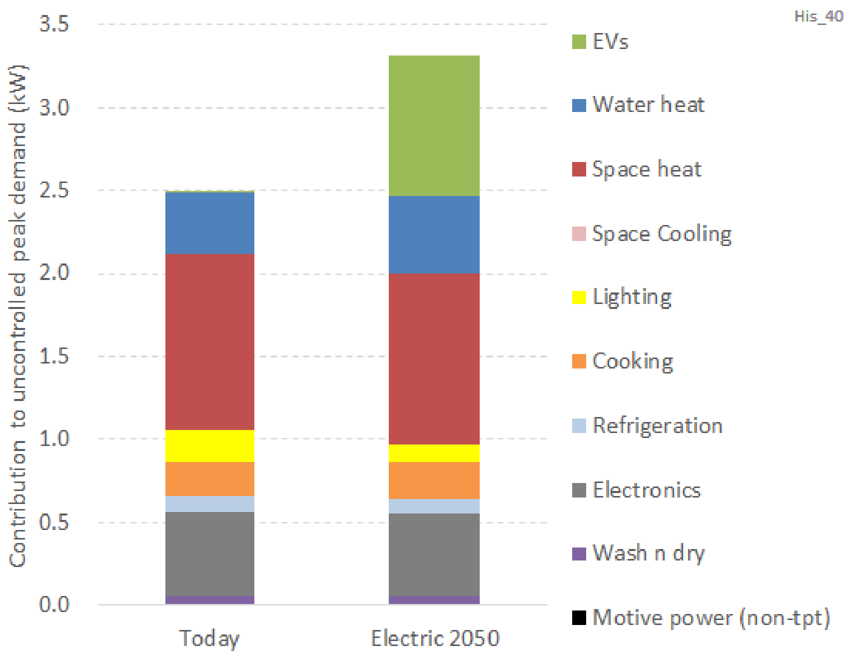
Figure 2: EVs are a major source of demand growth



Whether growth in demand for electrical energy (TWh) also drives strong growth in peak power demand (GW) is uncertain and will heavily depend on how well we use the flexibility inherent in hot water cylinders and EVs.

Figure 3 compares the peak demand from an average household today, with projected peak demand from an average household in 2050 in a scenario with unmanaged demand – that is, EV owners plug in and charge on arrival home and hot water cylinders are not programmed or controlled to avoid peaks.

Figure 3: EVs and water heating could increase peaks



In this scenario:

- electric water and space heating has replaced gas in many homes, and many homes have EVs
- energy demand (kWh per year) has increased by around 40%, from just over 7,000 kWh today to just over 10,000 kWh (refer to Appendix A for energy demand chart)
- increased peak demand (kW) from heating is relatively modest (due to greater use of heat pump technologies) and is offset by improved efficiency (on average) of lighting and refrigeration
- taking diversity effects into account, EV charging could increase peak demand per household by around 30%.

Diversity effects are an important contributor to this picture. People naturally arrive home at different times, with batteries at different states of charge. Even if everyone plugs in and starts charging as soon as they arrive home, charging demand will naturally be spread out across an evening.

Even in this unmanaged scenario, electrification at one level may appear to improve the efficiency of the electricity system – ie, it delivers 40% more energy to households while needing only 30% more capacity.

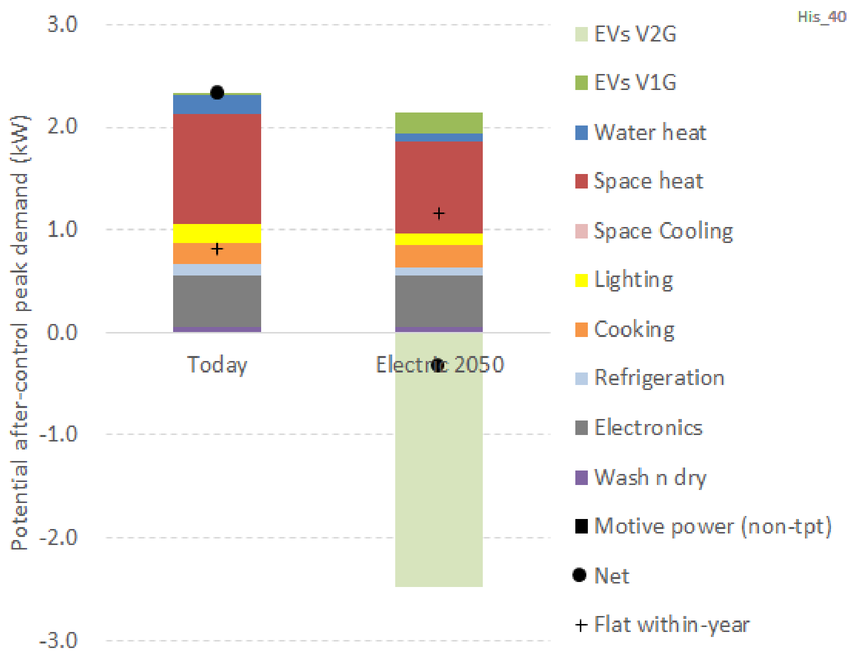
In practice:

- investment to add capacity to electricity networks is 'lumpy' and expensive, and likewise
- reliably generating energy at peaks is more costly than supplying off-peak energy.

As such, this unmanaged scenario represents a relatively costly future with deteriorating cost per unit of energy – before considering the effects of non-household demand.

Fortunately, household demand for water heating and vehicle charging are extremely flexible. Figure 4 repeats the comparison above, but this time with managed water heating and vehicle charging.

Figure 4: EVs and water heating are flexible demands



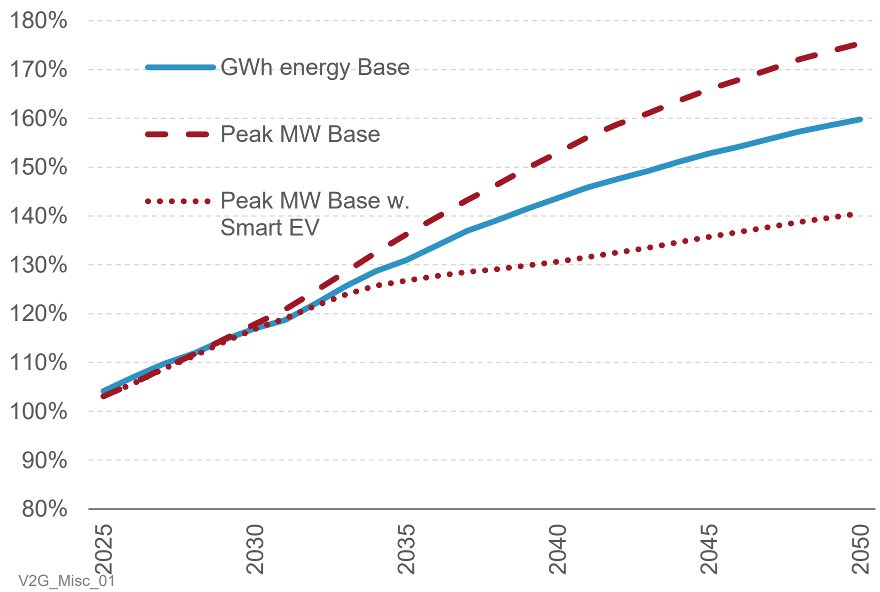
In this scenario:

- the energy (kWh) picture is the same as before, with a 40% increase due to electrification of heating and transport coupled with some efficiency gains, including from heat pumps, lighting and refrigeration
- smart charging ("V1G") and hot water control, combined with efficiency gains for space heating and lighting, produce a *reduction* in peak demand (kW) per household
- V2G has enough capacity to, on average, shift household demand away from peak periods entirely.

This 'average household' analysis provides a powerful insight into the potential of smart charging and V2G, as well as the enduring value of hot water control (for which New Zealand has a long and successful history).

To gain a more complete picture, we need to consider demand across all households and non-household energy users. Figure 5 presents Concept's base case forecast of changes in energy (GWh) demand and peak (MW) demand – with the peak demand showing two scenarios for the extent to which smart EV outcomes (ie, smart charging and V2G) are achieved.

Figure 5: Demand growth scenarios



In this modelling, by 2050:

- total energy demand increases by 60%

- transport electrification, including private vehicles, is the biggest contributor to this increase, followed by industrial electrification and growth (in population and economic activity)
- in our base scenario, which assumes limited smart charging and V2G, peak demand grows by 75% – ie, by more than energy demand
- with greater deployment of smart charging and V2G, peak demand only grows by 40%. – ie, by less than energy demand.

This more complete picture presents a higher increase in peak demand than our household-level analysis because it:

- includes non-household demand, and growth in the number of households
- assumes realistic levels of hot water cylinder control, smart charging and V2G participation.

Nonetheless, there is clearly significant potential for smart charging and V2G participation to support a more efficient and productive electricity system.

At a high-level, we estimate a difference in electricity supply cost in 2050 between these two scenarios as $310m per year, comprising:

- $40m per year from lower generation costs
- $270m per year from lower network costs.

How sensitive are our results to demand uncertainty?

The values given above and further in this report are significantly predicated on V2G avoiding supply costs associated with meeting increases in demand. However, while many forecasters have been projecting significant electrification-driven increases in demand from the early 2020s, NZ demand has remained flat and has actually been falling most recently.

While we are projecting demand increases in coming years – albeit at lower levels than many other forecasters – we acknowledge there is significant uncertainty as to the extent of demand increases.

However, we don't think this uncertainty materially alters our assessments of the value of V2G. This is because EV uptake is a very large driver of forecaster demand increases. If EV uptake is significantly driving costs, there is inherently the potential for V2G to offset those same costs, with costs and benefits per vehicle being broadly similar, regardless of the rate of EV uptake.

2.3 Raw value per vehicle

The earlier analysis has provided a per-average-household demand perspective, and national demand and value perspectives.

Now, we use the same underlying modelling to provide a per-vehicle value perspective (ie, $ per vehicle). In this sub-section we start with 'raw' values and then, in the following sub-section, consider factors that may impact the realisable value.

To build up the raw value per vehicle, we consider two supply cost components (generation and network) and four representative vehicle types:

- commuter car – used for both weekday commuting and weekend driving
- weekend car – parked at home on weekdays and used for weekend driving
- delivery truck – used extensively on weekdays. Returns to base early evening with 20% usable capacity. Parked at business premises on weekends
- milk tanker – used all-day and all-week during milking season, morning only during shoulder milking periods. Returns to base

with 10% in peak season and 55% in the shoulder season. Unused in the off-peak season.

We assume injection capacities of 7.4 kW for the cars, 50 kW for the delivery truck and 100 kW for the milk tanker.

To assess generation value, we:

- use simulated wholesale electricity prices averaged across three years (2028, 2037 and 2047). The prices directly reflect the marginal cost of supply at each hour of each year based on the projected state of the power system (ie, demand shape and available generation)
- simulate the net payoff for each vehicle type from injecting when prices are high and replenishing the battery ready for a 6 am departure, taking account the extent to which vehicles will be plugged in and have sufficient battery charge to provide V2G at different times of day for the different vehicle types.

To assess network value, we use an estimated capacity cost, based on our analysis of network disclosures, of up to $153 per kW per year. This is built up from:

- $132 per kW per year for distribution. This is our estimate of the long-run average cost of accommodating additional peak demand in local networks
- $21 per kW per year for transmission. This is our estimate of the long-run cost of serving a peakier demand profile.

We use lower figures for the trucks, because they connect at higher voltages deeper into the network (and so use less of the network).

We use the network values alongside electricity prices in our simulation of the net payoff for each vehicle type of targeting both high price periods and peak demand periods (noting these do not always coincide in a highly renewable system).

We also considered ancillary services, such as reserves, and concluded the additional value available is comparatively immaterial.

Putting these analyses together, we find the values for each vehicle type in Table 2.1.

Table 2.1: 'Raw' value per vehicle

Vehicle	Value ($/kW/yr)			Size (kW)	Value ($/yr)
	Energy	Network	Total		
Commuter car	130	150	280	7.4	$2.1k
Weekend car	210	150	360	7.4	$2.7k
Delivery truck	85	130	215	50	$10.8k
Milktanker	135	100	235	100	$23.5k

These are meaningfully large values in the context of household energy budgets and fleet operation costs. Next, we consider factors that may impact the realisable value.

2.4 Realisable value per vehicle

Key factors impacting how the figures above translate into values that can actually be realised by EV owners are:

- local injection saturation – as penetration of V2G grows, the ability of local networks to accommodate injection will eventually become a limiting factor. This is most relevant to the energy component, since the network component always coincides with peak demand, whereas high energy prices can also occur when supply is tight (even if networks are not so heavily loaded)
- stationary battery competition – as well as underpinning EV uptake, the falling cost of batteries supports growing penetration of stationary batteries at premises, in distribution networks, and

at grid (transmission) level. Of these, distribution-level batteries have the greatest potential to curtail (but not eliminate) realisable value by reducing the cost of network capacity

- local variation – the network figures are based on long-run averages. In reality some parts of some networks have ample capacity, with little or no benefit to be gained from reducing peak demand (while others have more acute benefit)
- monetisation gaps – it is not always possible to construct price signals or contracts that reliably translate underlying sources of value into an actionable consumer pay-off
- V2G costs – these include direct equipment costs (eg, for a suitable charger) and service costs (eg, for a retailer to manage billing and coordination).

Considering these factors, it seems V2G has the potential to follow a trajectory with the following broad phases:

1. near-term – the potential per-vehicle value from V2G is high, technical feasibility is maturing and becoming affordable, EV penetration is low but growing. The key obstacle is establishing coordination platforms (technical and commercial) on which consumer services can begin to flourish, providing early benefits for New Zealand and attractive realisable value for earlier adopters
2. mid-term – the technical and commercial platforms are in place and support an ecosystem of consumer services. V2G produces strong benefits and healthy realisable value for earlier adopters
3. longer-term – the realisable value per vehicle reduces, but services are mature, barriers to participation are very low and participation remains high.

The transition from mid-term to long-term is partly illuminated by comparing our per-vehicle analysis with our whole-of-system analysis. The former is more consistent with the near and mid-term, where EV and stationary batteries penetration is not yet high enough to have suppressed the value on offer. The latter represents a fully optimised system, with optimal levels of battery storage on the system.

With this trajectory in mind, the clear priorities today are to establish the technical and commercial platforms that enable service providers to recruit participation from early adopters.

Next, we consider V2G from a consumer perspective, then turn to the technical and commercial platforms.

For more on value opportunity, refer **Appendix A:**

3 Consumers have a choice

V2G is a complex service to bring to market – it involves novel use of an already novel technology (EVs) and requires multiple inputs and actions to translate into a sufficiently seamless service to gain wide consumer acceptance.

Without broad consumer interest and participation (ie, beyond niche enthusiasts) V2G has no real prospect of living up to its potential of both improving the efficiency and productivity of the power system and spurring EV uptake.

Consumer interest and participation is more critical for V2G than for more familiar (in New Zealand) hot water ripple control technology.

To compare the two, consider that:

- ripple relays are typically installed and configured as part of establishing a new connection (eg, when a house is built) and maintained alongside compulsory metering
- the comms layer for ripple control is inherently bundled into the network service (ie, the signal is sent via the distribution network itself)
- these factors historically made it possible for (some) distributors to insist on ripple installation, or to set higher charges for properties without ripple control
- once ripple is installed at a property, any hot water cylinder will (provided it is wired to the correct circuit and the relay remains functional) operate on command (ie, turn off)
- no consumer intervention (or even awareness) is required to maintain performance.

In other words, ripple control is 'low touch' for consumers and largely delivered alongside the monopoly network portion of electricity supply. Ripple participation does not really need any active consideration or attention from consumers.

In contrast, for V2G:

- vehicle chargers (and EVs) are usually consumer-selected and are typically retrofitted (for chargers) to existing properties
- the value stack spans generation and networks, so cannot rely solely on distributors to unlock via network standards and tariffs
- in addition, in an increasingly renewable power system, high wholesale prices will sometimes occur away from demand peaks so that control focussed only on network needs will not catch the full share of the total value
- as such, retailers are the natural party to coordinate V2G (taking inputs from distributors for network value).[2] New Zealand has a competitive electricity retail market, so retailer selection is up to individual consumers
- V2G is also only available if a vehicle is at the property, has sufficient stored energy, and is plugged into the charger.

Putting these factors together, V2G enrolment and participation clearly depends very strongly on consumer choice.

Fortunately, the value on offer has the potential to provide a compelling consumer proposition.

2 Non-retailer aggregators could also have a role to play. However, a retailer is the party most likely to engage with consumers, even if the retailer engages an aggregator to help deliver their services.

For example, it is quite plausible for V2G earnings to cover the entire fixed electricity charge for an Auckland household.[3] Through a transport lens, earnings from V2G can materially reduce vehicle ownership costs – making EV ownership more attractive and attainable.

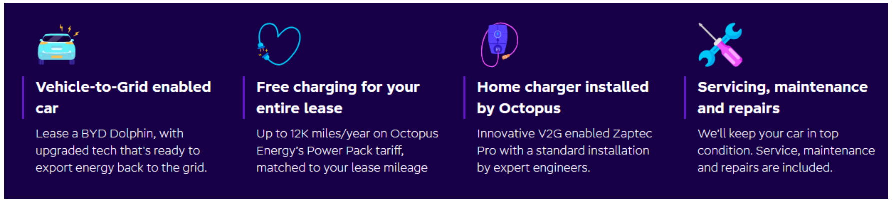
3.1 Case study – Octopus UK and BYD

This dual value proposition and consumer choice dynamic is neatly illustrated by Octopus Energy's marketing of a "Power Pack Bundle" offer in the UK that combines:

- an EV lease from BYD (including vehicle servicing)
- a home charger from Zaptec (including installation)
- free at-home vehicle charging.

This set of services are supplied for a single monthly fee and marketed alongside Octopus Energy's electricity retail services and its other (unbundled) EV leasing services.

Figure 6: Octopus Power Pack Bundle



Sitting behind the offer headlines, the service includes:

- technical eligibility criteria that ensure the charger can be installed at the property, can inject up to 5 kW into the network, Octopus can manage charging remotely, and the metering at the property is suitable
- behavioural eligibility criteria that include a requirement for the car to be plugged into the charger for at least 12 hours per day for at least 20 days per month, and a requirement to inform Octopus of vehicle usage preferences (such as departure time and target state of charge)
- commercial eligibility criteria, including a requirement to also purchase non-vehicle electricity from Octopus and to not sign the vehicle up for any other demand response service (ie, control rights are exclusive).

The ability for Octopus to present an attractive 'sticker price' for the bundle is supported by the value Octopus achieves through smart charging and V2G. The consumer does not need to engage with the complexity of the power system or network pricing to understand and benefit from the value on offer.

To make this possible, Octopus (and the wider UK power system) have had to line up and package:

- a V2G-capable EV and charger combination, and associated installation and servicing arrangements
- technical platforms for controlling and optimising the leased vehicles
- distribution network standards and processes for safely accommodating V2G injection
- generation and network pricing arrangements that provide a payoff (whether payments or bill reductions) to reward load reduction and injection

3 Average daily charge is currently $2.76 for 'standard user' households in Auckland, or just over $1,000 per year. https://www.ea.govt.nz/industry/monitoring/regional-power-prices/

- electricity retail arrangements, including 'type of use' tariffs that bill for EV charging separately from other energy usage at a property
- a sales channel that puts this option in front of people considering a vehicle lease.

3.2 Success factors

The context for V2G in New Zealand is quite different from the UK. On one hand, we have disadvantages (in comparison to the UK) of:

- considerably smaller vehicle, vehicle charger, and retail electricity markets
- relatively incomplete, immature and lightly resourced regulatory arrangements for monopoly network services (including with respect to asset management, network access arrangements, and pricing)
- a fragmented electricity distribution sector, with a large number of relatively small networks with limited consistency in terms of technical standards, connection processes and commercial settings.

On the other hand, we have advantages that include:

- more sophisticated and cost-reflective generation and transmission pricing arrangements (ie, locational marginal pricing)
- comparatively strong (ie, high capacity) distribution networks (due to much lower penetration of natural gas for household space and water heating)
- a greater portion of households and businesses with off-street parking (enabling a consistent relationship between a consumer, a vehicle and a network location)
- comparatively simple jurisdictional arrangements, with one central government, nationwide regulators and very limited cross-border vehicle movement.

In this light, success factors for V2G in New Zealand include:

- Trans-Tasman alignment for EV and EV charging standards (including communications and control). This is valuable for achieving meaningful scale from the perspective of vehicle and charger suppliers
- national alignment for distribution network standards and pricing arrangements. Price levels may vary around the country, but consistency of the 'menu' of structures and standards is valuable for achieving viable scale from the perspective of parties developing retail services or service bundles that leverage V2G value streams
- ensuring value streams are accessible to potential retailers, whether or not they are traditional electricity sector participants.

Next, we consider the technical platform for V2G in New Zealand.

For more on consumer issues, refer **Appendix B**:

4 Technical platforms enable V2G

There are escalating technology platform needs for:

- smart charging (V1G) – stopping or throttling charging on demand
- vehicle-to-premises (V2P) – injecting power from a vehicle into a grid-connected property to partly offset its demand, but not to a level that results in net export from the property, and
- vehicle-to-grid (V2G) – either injecting directly into the local network, or injecting more power than a property is consuming, such that the property as a whole injects power into the local distribution network.

Technology platform requirements span several layers:

1. the EV – including its onboard power handling, and potentially its communications, control and metering capabilities (where these functions are not provided by the wall charger)
2. the charger – including its power handling and communications with the vehicle, its remote communications, control and metering, its integration with the property and (if injecting) with the distribution network[4]
3. the connection (from the premises to the local distribution network) – including its capacity, metering and control
4. the local distribution network – including enabling safe maintenance and emergency management, operational awareness, setting and communicating injection limits, and ensuring power quality (eg, voltage and harmonics)
5. the national grid – including the need to understand and manage risk and to deploy resources in emergencies.

The intensity of many of these needs increases with penetration of smart charging and V2G – ie, as the aggregate size of changes in demand, and the aggregate level of injection, become material at local low-voltage networks, then the wider distribution network, regional transmission network, Island-wide power system or national power system levels.

Below we survey state of play and make observations on future needs at each layer.

We note that cybersecurity is an essential consideration for any digital control systems and is especially important for systems with remote access and control and material operational risks. However, exploring specific cybersecurity considerations is outside the scope of this report.

4.1 Vehicles

EV motors and batteries use direct current (DC) power, while the power system uses alternating current (AC). Power is converted from AC to DC for charging, and for V2G power stored in the battery must be converted back to AC.

Conversion requires relatively expensive equipment that can be fitted in the vehicle or an external charger, and can support charging only, or two-way power transfer (and hence V2G).

All light EVs (cars, vans, utes) and some heavier EVs (smaller trucks and buses) have on-board converters so they can receive AC power – avoiding the cost of installing an external DC charger.

[4] We use the term ‘charger’ to refer to external EV supply equipment (EVSE), also known as a charge point or charging station). We use this term even for situations where the vehicle has an on-board converter that can deliver grid-compatible power and the external AC ‘charger’ doesn’t have its own converter. Other than in very technical forums where such distinctions are necessary, the colloquial use of the term ‘charger’ to cover both situations aids readability without compromising accuracy.

A 3-pin plug and relatively simple cable (with in-cable control and protection) can supply 1.5-3kW, while an at-base external AC charger can supply up to 7.2 kW, and public AC charge points can supply up to 22 kW.

Providing V2G from light vehicles has to date usually required an external DC charger with its own bidirectional converter. The cost of bidirectional DC chargers has been high enough ($10-12k historically) to practically eliminate the realisable value of V2G. However, the latest generation of DC chargers have fallen in price to $5-7k, significantly improving the net cost-benefit of V2G from light vehicles. As the market develops, further cost reductions are likely, improving the economics of V2G from light vehicles even more.

More recently, EVs are becoming available with on-board bidirectional converters. This offers the potential for V2G using even lower-cost AC chargers (around $1.5k).

While AC V2G offers another path to V2G participation, it requires vehicle manufacturers, charger suppliers and distribution networks to all be comfortable with the safety and performance of the combined system.

For the New Zealand market, the key to making this happen is to align vehicle charger and relevant electrical standards with those that will be used in the Australian market – including joint AS/NZS standards and international standards adopted in Australia.

For vehicle manufacturers and importers, this helps them to understand and cater for the Trans-Tasman market.

Fortunately, Australia and New Zealand have common high-level power supply settings (voltage and frequency), both use CCS2 as our main EV charging connector standard and are typically viewed as a single market by global vehicle manufacturers (and charger suppliers).

New vs used imports (CCS2 and CHAdeMO)

New Zealand-new EVs use the Combined Charging System 2 (CCS2) connector standard and associated ISO15118 communication protocol (for communication between the EV and the external charger) for AC and DC charging.

Used Japanese import EVs use the CHAdeMO connector standard and associated communication protocol for DC charging, and this has been natively capable of DC V2G since its inception.

Used Japanese import EVs use the SAE J1772 Type 1 standard for AC charging, which is not standardised for bidirectional power transfer.

Until recently, the CCS2 communication protocol did not have a standardised way of managing bidirectional power, materially hindering its usefulnessfor V2G. However more recent versions of ISO 15118 are fully V2G capable and starting to be used in New Zealand new EVs.

CCS2 is now the dominant charging standard in New Zealand and provides a suitable platform for low-cost AC V2G.

Heavy vehicles

Most heavy vehicles (eg, larger buses and trucks) do not have on-board converters as it would take too long to charge their large batteries using AC power. As such, heavy vehicles must have an external DC charger with its own converter.

While many DC chargers to-date have not been capable of V2G, some newer DC chargers are V2G enabled and can be upgraded at relatively low cost (eg, with a software update).

The new Megawatt Charging System (MCS) for heavy vehicles uses the ISO15118-20 communication protocol and is natively capable of V2G.

From vehicle manufacturers and suppliers, key enablers for V2G are then:

- supply of “grid-ready”
  - vehicles with AC V2G functionality installed and enabled, or
  - DC chargers with full V2G functionality
- vehicle manufacturer warranties that permit V2G usage
- provisioning over-the-air or vehicle servicing network vehicle updates to support ongoing compliance as standards evolve.

Battery degradation and warranties

Batteries lose capacity over time due to calendar ageing (time) and cyclic ageing (usage).

Early studies, based on the type of battery technology found in the first-generation Nissan Leaf, concluded that V2G would accelerate battery degradation.

More recent studies, testing the more modern batteries found in the Hyundai Ioniq 5 found V2G resulting in a reduced rate of degradation relative to the situation of no V2G up to around 150,000 km, and making negligible difference to the extent of degradation at 350,000 km. Other researchers have concluded that V2G can be used to optimise and extend battery life, and real-world use has tended to demonstrate better performance than indicated by laboratory testing.

EV battery warranty periods in New Zealand are commonly 8 years or 160,000 km, with some manufacturers offering 10 years and 250,000 km. CATL now produces bus and truck batteries with claimed lifespans as high as 15 years and 2.8 million km.

Warranties typically exclude V2G usage today, so OEMs updating this practice as the market demand for V2G emerges and grows would remove a significant barrier to V2G uptake.

4.2 Chargers

The key external charger requirements for unlocking V2G are:

- vehicle compatibility
- grid compatibility
- remote communications and control.

4.2.1 Vehicle compatibility

For light vehicles:

- DC chargers with V2G capability are an option but, to-date, have been sufficiently costly to present a material barrier to V2G uptake. Recent falls in DC charger costs have significantly reduced this barrier and, if costs continue to fall, will further improve the economics
- AC chargers with V2G capability may become a more affordable option, provided EVs with bidirectional onboard converters become more common.

It is yet to be seen whether vehicle manufacturers will head down the bidirectional onboard converter route. This is not a straightforward option, given differences in electricity systems around the world.

Some EV manufacturers (including BYD, now the world’s largest supplier of EVs) have indicated they will head down the DC V2G route. If other major manufacturers head down the same path, this is likely to drive further price reductions in DC V2G chargers as production volumes and competition increase.

Most heavy vehicles do not have onboard AC convertors and rely on external DC chargers to supply enough power to enable realistic charging times. V2G capability has not been common to date in DC chargers but is a comparatively affordable feature to include (or retrofit to) newer DC chargers – including chargers compatible with the new Megawatt Charging System.

4.2.2 Grid compatibility

To be wired into a property and inject power from an EV, a charger must meet a set of technical requirements designed to ensure electrical safety and grid performance.

Standards setting is predominantly the domain of national-level regulatory bodies, including:

- WorkSafe and MBIE administer electrical safety regulations. These arrangements are in the process of being updated to streamline the process for adopting updated standards. This will enable references to AS/NZS 4777.x standards for inverter systems to be updated from the 2005 version (that does not contemplate V2G) to the 2024 version (which does)
- MBIE recently consulted on whether "smart" functionality should be mandatory, and whether to introduce consumer labelling requirements[5]
- Standards NZ maintains publicly-available specifications (PAS) for EV chargers[6] and EECA has lists of chargers that meet efficiency and smart charging requirements.[7]

In addition to national-level requirements, individual distribution networks may have their own requirements for connections to their networks. We discuss this at section 4.4.

As with vehicles, alignment with Trans-Tasman standards helps ensure New Zealand can be treated by charging equipment manufacturers and suppliers as part of a larger market.

This in turn helps support availability of a wider range of equipment available at competitive prices, that are compatible with the vehicle fleet and local network requirements.

Standards relating to V2G are likely to continue to evolve, so it's beneficial for regulatory arrangements to be set up to adopt new iterations quickly or automatically, rather than needing changes to primary legislation or overly cumbersome amendments to secondary legislation.

4.2.3 Remote communications and control

The other key part of the charger-level platform is the remote communications and control technology stack – ie, the systems for sending commands to a charger and transferring information to and from a charger.

The communications and control technology stack includes:

- communications protocol(s) – ie, the low-level structure of commands and information
- local communications technology – eg, direct-to-charger cellular communications, or local area network
- (sometimes) a gateway device – eg, an at-site "smart home" hub or commercial building management system that provides

5 https://www.mbie.govt.nz/dmsdocument/30885-proposals-to-support-uptake-of-smart-electric-vehicle-charging
6 https://www.standards.govt.nz/get-standards/sponsored-standards/residential-electric-vehicles-ev-charging
7 https://www.eeca.govt.nz/regulations/voluntary-guidance/ev-smart-charger-approved-list/

local control and may enable remote control, interrogation and alerts

- remote gateway services – ie, a system for remotely registering chargers and coordinating communications
- control services – ie, the system for turning all of the above into useful services for consumers, and other parties wishing to access V2G functionality. This may include business-to-business interfaces, and a consumer front-end (eg, an app).

There is value in contestability and competition at the services levels (remote gateway and control), as this helps with finding service propositions and enrolment strategies that grow and maintain the V2G resource pool, and apply it to its highest value uses over time.

However, there is also likely to be value in persistent (ie, regardless of services providers) ability for the power system to interact with V2G chargers. For example, this may include:

- awareness to inform system operation and network planning
- communicating network system limits, including emergency curtailment or more routine "throttling"
- transfer of network billing information, potentially including tariff structures and levels and demand (or injection) quantities.

There are a range of potential communications and control topologies for enabling charger (or vehicle) communications and control, and there is considerable effort being invested globally in standards development to support interoperability.

For example, the latest iteration of Open Charge Point Protocol (OCPP), which focusses on EV charge point management, supports integration with IEEE 2030.5, which focuses on the 'smart grid' communications needs of electricity networks. Both protocols can be used with OpenADR, which focuses on coordinating flexible energy resources.

Taking a view on the optimal technology and service topology pathways is beyond the scope of this report, but the key success factor is ensuring interoperability and integration at a level that enables:

- contestability of control services – this is essential for unlocking the energy component of the value of V2G, which is roughly half the available value
- a sufficiently reliable platform for meeting network needs, including ensuring system limits are respected and power quality is not compromised
- consistency between distribution networks so that the vehicle, charger, and service providers can treat New Zealand as a single market in terms of provisioning technologies and capabilities (even though use of those technologies and the value payoff will vary by network and even within networks).

4.3 Network connection

When a connection converts from off-take only, to off-take and injection, network access is governed by the same Electricity Industry Participation Code (Code) rules that apply to generators connected to distribution networks.

As well as governing connection process and pricing requirements, the Code provides a framework for distributors to set technical requirements for connecting injecting equipment (including V2G) to their networks.

While the Code provides a degree of nationwide consistency, individual distributors are required to maintain their own "connection and operation standards".[8] These:

- may in some cases contain technical requirements for chargers at non-injecting (offtake-only) connections
- are likely to contain requirements for V2G chargers – ie, to ensure injection does not cause safety, power quality or capacity management problems on the network.

While the requirement for distributors to have connection and operation standards is long-standing, there has not been substantive or concerted oversight of the consistency and quality of those standards.

From a V2G point of view, it is desirable for connection and operation standards to:

- align with national equipment and safety standards (which in turn should support Trans-Tasman alignment)
- err on the side of not creating local (distributor-by-distributor) variations that risk fragmenting EV, charger or V2G control services markets.

Sector collaboration can help with these goals, but a mechanism for regulatory monitoring and override could be beneficial if tensions arise been local network drivers (and preferences) and the value of nationwide (and Trans-Tasman) consistency.

4.4 Distribution network

As penetration of V2G, stationary batteries, and rooftop solar increase there is an escalating set of issues for distribution networks to manage:

1. safety – ensuring each individual injecting connection is safe and does not harm power quality
2. stability – ensuring injecting connections collectively do not compromise safe and secure network operation. This can involve setting device standards and enhancing the distribution network (eg, with power electronics devices)
3. monitoring – understanding aggregate injection at various levels of the network (down to local LV transformers and lines) to inform operations and planning
4. containing – implementing systems for ensuring injection does not violate network limits (ie, does not overload network assets)
5. incentivising – encouraging injection toward lower-impact times of day (and spread out to avoid creating injection peaks)
6. harnessing – leveraging injection to push back the timing of network capacity upgrades.

The first four issues in the escalation path form part of the technical platform for V2G, while the last two are primarily commercial platform issues, but bring their own technical platform requirements.

In Australia, rooftop solar has been the driving force for this escalation and solutions have evolved in that context. In New Zealand, we have had more cost-reflective settings for solar and hence more gradual uptake. This means that distributors are beginning to work their way up the escalation path with:

[8] The Electricity Industry Participation Code requires distributors to have connection and operation standards for injecting connection, plus network connection standards. We refer to the former here, but both may be relevant.

- the benefit of observing and learning from Australian approaches (and other countries)
- V2G as a more mature technology (relatively speaking) and hence more salient consideration.

As we move up the escalation path:

- the relevance and importance of Trans-Tasman alignment diminishes, because the technology platforms for coordination should sit atop the more basic electrical standards and control and communication platforms that are relevant to suppliers of EVs and chargers
- it becomes more relevant and important to fit solutions to New Zealand's power system context, and to provide nationwide consistency. This is important for creating market scale, which in turn supports consumer recruitment and value.

4.5 National grid

As penetration grows, a similar escalation path becomes relevant for the transmission grid and for operation of the national power system (ie, for Transpower in its distinct Grid Owner and System Operator roles).

The escalation path for transmission lags the leading distributor (ie, the distributor with the highest penetration) but may progress ahead of other distributors.

The transmission system is already set up to deal with injection, so more of the technology platforms are already in place at transmission level.

However, small-scale distributed devices reacting to remote coordination systems present novel issues for the Grid Owner and System Operator.

As such, it is important that the technology platforms developed by distributors are set up in a way that will enable them to meet the future needs of the Grid Owner and System Operator.

Examples of these needs may include:

- awareness of available resources and their aggregate behaviour to inform planning and operations, including identifying and mitigating risks to power system stability
- an ability to enforce transmission system limits to protect grid integrity
- an ability to incentivise and harness V2G resources (including in an emergency).

For more on technical platforms, refer **Appendix C**:

5 Commercial arrangements activate and orchestrate V2G

Alongside the technical platform for V2G, New Zealand needs to evolve a suitable commercial platform that:

- coordinates how V2G is deployed
- compensates V2G service providers
- incentivises useful V2G participation.

Elements of the commercial platform can include:

- network or device 'readiness' standards
- network charges
- network payments
- flexibility register.

5.1 Readiness standards

Given V2G is potentially very valuable, but not yet a mature and familiar service, readiness standards could play a useful role laying the foundation for future commercial platforms.

Readiness standards could apply to:

- external chargers – eg, requiring chargers sold in New Zealand (product standard) or installed (network standards) to support prescribed communications and control standards out of the box (or with a modular upgrade)
- property wiring or metering – eg, requiring chargers to be connected to a dedicated circuit and meter register.

At their best, readiness standards:

- materially reduce barriers to future V2G enrolment and participation – ie, make it easier to activate V2G in future
- would not add disproportionate cost – ie, be introduced at a time and in a form such that incremental costs are modest, bearing in mind that many consumers will never choose to activate V2G
- assist with (or at least, not detract from) Trans-Tasman compatibility and nationwide interoperability
- support competition (ie, avoid lock-in to a single service provider or appliance provider).

MBIE has recently consulted on appliance readiness standards.

There may be scope for distributors to add value with network readiness standards, provided they complement appliance standards (if introduced) and promote the outcomes listed above.

5.2 Network charges

Distributors:

- set up-front connection charges for new connections (and connection upgrades)
- annually update 'posted tariffs' that determine the basis for the monthly bill for each connection
- assign each property (or connection point) to a tariff category (also known as a consumer group).

5.2.1 Connection charges

Connection charges are paid by connection applicants and provide the first opportunity to incentivise smart charging and V2G.

For example, connection charges may be higher for a site with uncontrolled injection (or offtake) from a high-power charger than one where the distributor is reasonably confident the charger can be throttled if needed.

Recently introduced rules for connection charging provide a foundation for this type of approach, with standardised methods for assessing the cost of upstream network capacity and provision for applicants to request a lower-cost ‘flexi’ connection.

This enables cost-reflective signalling of the benefit from flexibility of enabling lower cost network design assumptions and capacity sizing.

The new rules do not come into effect until April 2026 (partial) and April 2027 (full). The Electricity Authority has signalled further reform may be in place from 2030 and is also reviewing related (and longstanding) arrangements for injecting connections.

The current arrangements for injecting connections are more restrictive, providing less scope to signal capacity sizing benefit of injection that is either flexible, or routinely scheduled to coincide with demand peaks. The Electricity Authority is currently reviewing these arrangements.

These regulatory changes provide a catalyst for distributors to reform their connection pricing methodologies. From a V2G point of view, it would be helpful if distributors aim for:

- greater harmonisation – from low-level matters (such as naming conventions), through to pricing structures and approaches, and even pricing levels
- supporting policies, standards and practices that enable flexi connections to become a reality.

5.2.2 Tariffs

Historically, distribution tariff practices in New Zealand have typically included:

- for households, relatively low fixed (per day) charges and relatively high energy-based (per kWh) charges
- for businesses (ie, larger connections), fixed (per day) charges based on broad capacity bands, plus a mix of other charge components such as energy consumption (kWh), peak power (kW) and distance (km)
- discounted ‘type of use’ (or appliance) tariffs for night-store heaters and ripple-controlled hot water cylinders
- no charges for injection.

Most distributors calculate charges for each connection point each month and invoice the retailer responsible for that connection point.

For retailers, network charges are one of two major input costs alongside energy, with metering, levies, and internal costs and margin making up the balance.

Retailers have traditionally structured their retail tariffs broadly in line with network tariffs – ie, with daily charges, usage charges, and type-of-use tariffs (where applicable).

Over the last few years, trends in network pricing for households have included:

- rebalancing toward higher fixed (daily) charges and lower usage (energy) charges
- adoption of time-of-use charges, with a trend toward near-zero off-peak usage rates and peak usage rates that signal the average cost of adding network capacity.

These changes together improve cost-reflectivity, reduce month-to-month variability, improve cost savings from electrification, and encourage off-peak EV charging.

Retail tariff structures have similarly evolved, with an increasing prevalence of low-cost off-peak rates – especially for households with an EV.

More recently, the Electricity Authority has introduced new requirements that:

- network tariffs for mass market consumers must include a ‘negative price’ for injection at time-of-use peaks – with the price set at the same level as the corresponding peak demand price
- certain retailers must offer (and promote) time-varying price plans for both consumption and injection
- distributors must assign connection points to time-varying plans
- retailers must submit accurate (half-hourly, where possible) connection point consumption data for billing.

These requirements will come into force over the coming year. Together, they add impetus to and extend the reforms that have already been in train.

While progress to date is positive, and a pragmatic fit with the current state of EV and V2G penetration, increasing penetration of V2G (and stationary batteries) will drive a need for further evolution.

This is because batteries (and hence smart charging and V2G) are very flexible and responsive technologies.

While EV penetration is low, and charging is mostly managed passively, time-of-use charging is fit for purpose. This is because it:

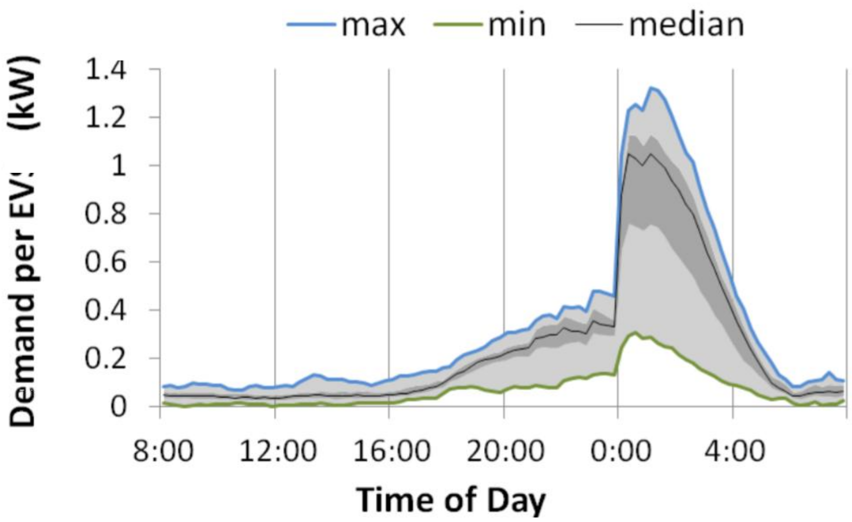
- encourages owners to prefer off-peak charging, which will tend to moderate the impact of EVs on peak demand
- cost-reflectively lowers the cost of EV charging, helping encourage efficient EV uptake.

However, time-of-use is not a durable solution and nor is negative pricing for injection.

Even without V2G, as penetration grows, managed or passive EV charging is likely to create a secondary peak at the start of the off-peak period – ie, as vehicles delay charging until the off-peak period, losing the natural arrival time diversity that otherwise softens EV charging peaks.

This effect has been observed in trials – for example, Figure 7 shows the pronounced midnight charging peak observed in a trial carried out by Pacific Gas & Electric in San Francisco.

Figure 7: Weekday EV charging demand in PG&E trial



Note: The x-axis starts at 8am

Our 2018 "Driving Change report"[9] presents quantitative analysis demonstrating that large-scale EV uptake with simple time-of-use pricing and smart charging would likely result in higher peaks than flat prices and uncontrolled charging.

This problem is most likely to emerge in "pockets" initially – eg, in streets or suburbs with high EV ownership, or in holiday spots during peak season (when EV numbers swell). As EV penetration grows, the problem is likely to extend across networks.

We have extended our earlier analysis to test how V2G may add to the problems with time-of-use pricing. We simulated outcomes from the following scenario:

- EVs have 7.4 kW chargers, managed V2G, and are plugged in overnight
- the network has time-of-use network tariffs, with injection paid at the same rate as peak period consumption charges (13.4 c/kWh ex GST)
- households have an average after-diversity peak demand of 2.5 kW (excluding EV demand).

We simulated behaviour with charging optimised to respond to the tariff (while preserving enough charge for daily travel needs). We found that:

- the EV *earns* $1,500 per year from network tariffs, plus an additional $50 from energy (ie, from buying at low spot prices and selling at higher prices, on average)
- the earnings would pay for the cost of a V2G charger in less than three years (compared to around 14 years for a stationary battery)
- if just 3% of households use V2G to respond time-of-use tariffs in this way, the secondary peak is more than 25% higher than the current evening peak.

This clearly illustrates that current (and soon to be introduced) mass market network tariff settings will not be durable as smart bidirectional charging matures.

The 'shelf life' for time-of-use pricing could potentially be extended by measures such as:

- reducing injection payment rates as V2G penetration increases – 'activated' V2G is relatively insensitive to the injection rate, but reducing the rate would slow enrolment (by extending the payback for V2G chargers)
- introducing injection capacity bands (eg, escalating fixed daily charges for injection above various kW limits). This could be used to provide a soft 'throttle' on injection levels and to soften the volume of replenishment demand.

While these modifications could extend longevity, they do not provide enduring solutions.

Notably, other traditional tariff types are similarly undermined by the responsiveness of controlled V2G. For example:

- locational marginal pricing within distribution networks would not mitigate 'battery dumping' risk unless combined with enforceable system limits down to LV level
- coincident peak demand charges (where charges are based on consumption that occurred at a connection point when the network was at its peak demand level) would prompt batteries to 'hunt' the peak and exacerbate the (already poor) consumer unfriendliness of such tariffs.

[9] *"Driving change – Issues and options to maximise the opportunities from large-scale electric vehicle uptake in New Zealand"*, Prepared for Orion, Unison, and Powerco, 7 March 2018. Available for download at https://www.concept.co.nz/updates.html

Ultimately, it seems the best solution for V2G is to adopt 'type of use' (or 'appliance') pricing. This is where the pricing for a specific use is decoupled from pricing for the balance of the property.

This approach has been used by many distributors for ripple controlled hot water cylinders, but an evolution of the basic approach would be beneficial when extended to cover both V2G and next-generation hot water control.

Ripple control of hot water remains very beneficial for reducing network peaks but should eventually be replaced with a more sophisticated technical platform that provides more fine-grained control and a platform for broader services (including consumer-facing services, and energy cost management).

Key features of next-generation type-of-use pricing for controllable demand could include:

- usage charged at (or near) the off-peak rate at all times. This reflects that controllable demand does not add to peak demand. This can apply equally to controlled hot water, EVs and stationary batteries
- tariff is open to devices controlled by any control platform and service provider that can meet eligibility criteria – eg, reasonably reliable response to curtailment commands at network peak, secondary peak mitigation, participation tracking and acceptable estimation of consumption volumes
- provider-estimated consumption volumes are netted off total connection point consumption – ie, so controlled devices do not need to be wired to dedicated registers on revenue-grade meters.

This approach signals the distribution network value of controllability, while enabling service providers to bundle this value with energy cost management and other consumer-facing features. It also supports contestability and, helps contain the cost of participation.

Distributors could take a similar approach to injection pricing. For example, with pricing that:

- offers more generous capacity allocation (eg, operating envelopes or injection bands) than uncontrolled injection – recognising that injection can be throttled on demand to manage injection peaks
- is open to any devices signed up with an eligible controllability provider (using an eligible control platform)
- allows use of provider-supplied injection volumes for billing (if the property has controlled and uncontrolled injection devices)
- also offers negative pricing if device is in a network location where injection is called on to manage demand peaks.

This approach would complement use of:

- capacity bands for injection – ie, where injection pays escalating fixed charges for injecting at higher rates. This is a price-based method for managing injection-driven network upgrade pressures
- operating envelopes – ie, where a distributor communicates injection limits to devices (either static limits, or limits that vary with network conditions). This is a non-price based method, though could be complemented with pricing mechanisms (such as higher charges for less restrictive envelopes).

There may be other pricing approaches that could work for V2G as well, but key points are:

- current arrangements will no longer be fit-for-purpose as V2G matures
- new arrangements need to accommodate competing platforms and service providers to enable energy cost benefits to be captured alongside network benefits, and to activate V2G participation

- accordingly, there is value in consistency across New Zealand to support platform and service investment, and V2G deployment
- a consistent approach can be adopted across EVs, hot water control and stationary batteries
- there is value to ensuring hot water control resources are not lost in the transition to new arrangements – ie, a temporary dip in controllability could prompt regretful investment in network capacity.

5.3 Network payments

Network tariffs provide a powerful tool for recruiting V2G and shaping its routine usage.

However, network tariffs are better suited to signalling averaged (across an area and over time) values rather than acute values – eg, where extra response in a specific location could help:

- defer a (relatively) near-term investment in new network capacity
- manage short-term capacity stress – eg, due to network damage, construction delay, or unexpected growth.

For these uses, payments from networks to service providers for 'deeper' response can complement tariffs.

This approach to network management becomes increasingly plausible as the penetration of enrolled controllable resources increases – ie, when service providers have already enrolled sizeable pools of potential response that can be deployed relatively quickly (in weeks, months or quarters).

To support the potential for this approach to function in future:

- the amount of response potential 'reserved' via type-of-use eligibility criteria should be small, and (within reason) relatively consistent across New Zealand. This leaves more room for non-network use as well as for deeper response
- a centralised 'flexibility register' and trading platform would help distributors assess available resource potential and test pricing with service providers.

5.4 Transmission benefits

Our earlier analysis suggests that, on average, the avoidable cost of transmission capacity is smaller than the value available from reducing demand for distribution network or generation capacity.

Intuitively, this reflects that a large share of transmission investment would be needed to enable energy growth even without growth in peak demand.

However, transmission deferral benefits can be high at certain times (ahead of an investment) and locations (downstream of a constraint).

There are two 'channels' by which transmission benefits are conveyed:

- spot prices – energy is priced in real-time at hundreds of points on the grid. Overall prices move up and down to reflect generation conditions, and local prices (at a node or across a region) vary to reflect transmission usage costs. These 'usage' signals are conveyed directly to energy purchasers (typically retailers)
- transmission charges – Transpower allocates the cost of each new investment to the customers predicted to benefit from that investment. For most energy users, costs are allocated to distributors who then bundle transmission charges into their monthly lines charges.

The usage signal conveyed by spot prices is readily actionable but does not capture the full transmission benefit. Transmission takes time to build and capacity is added in large increments. This means Transpower has to add capacity ahead of demand, which tends to dampen congestion and suppress spot price signals.

The signal provided by transmission charges (specifically benefit-based charge component of transmission charges) is less readily actionable. It involves:

- acting ahead of Transpower committing to build an upgrade
- anticipating how beneficiaries will be assessed (and hence who will have to pay for the upgrade)
- a party (ie, an 'agent') choosing to act on this information to coordinate a response that will defer the investment.

Retailers are not a suitable agent for this response, because avoided transmission charges benefit all consumers on a network (not just their own). This means they cannot capture the benefit and hence cannot fund the response.

The other potential agents are Transpower, and distributors.

In theory, Transpower can recover the costs of paying for actions that enable it to defer investment – so-called non-transmission solutions. This is practically challenging where Transpower cannot:

- be confident at the time it chooses not to invest (which may be years ahead of projected need) that the actions will be effective
- determine how much it needs to pay to produce the desired response.

Both of these impediments could reduce as V2G (and next generation hot water control) matures – ie, as the pool of enrolled EVs grows and information about the depth of response elicited by differing payment levels becomes clearer. In addition, Transpower's motivation to pursue this type of option may well strengthen as its work programme grows.

The pathway toward Transpower adopting this type of approach could potentially also be eased by updating grid reliability standards (or GRS).

The GRS is a planning standard that plays a key role in determining how much capacity and redundancy Transpower must build into the grid. The GRS has not been reviewed for 20 years and could potentially be refined to make it easier for Transpower to adopt non-traditional solutions.

In theory, distributors could also act as agents. There are two ways a distributor could do this:

1. price signal – a distributor could structure its tariffs to signal (its estimate of) the future cost of a grid upgrade. This would increase the payoff from actions that help defer the upgrade
2. payments – a distributor could pay for actions that push back a grid upgrade (and hence its transmission charges).

Neither option is straightforward or without challenges, such as:

- translating Transpower's grid investment plans into projections of future transmission charges, and then into distribution pricing signals, is a complex and uncertain exercise for which the distributor receives no direct benefit[10]
- transmission charges are a 'pass through' cost for non-exempt distributors, whereas paying for a response may not always be a recoverable cost. In other words, it can be easier for a distributor to recover tangible transmission charges than to recover the costs of paying for actions that *may* reduce future charges.

[10] This is less challenge for a distributor's own grid connection, as they are directly involved in Transpower's planning and directly exposed to the costs.

These are relatively complex issues to resolve, however the viability of V2G does not depend on being able to realise transmission benefits and as V2G matures the ability to leverage it for transmission deferral should grow.

5.5 Flexibility register

As the penetration of remotely controllable devices increases, there is increasing value in recording information about:

- the location and properties of controllable devices
- the existence and properties of 'flexibility units' – that is, collections of resources in a given location with common control arrangements in place.

These are distinct information sets, which both have value.

Information about devices (such as a controllable hot water cylinder, V2G charger or stationary battery) provides 'raw' information about demand and injection that could potentially:

- cause network or system operation risks if uncontrolled (or poorly controlled)
- be recruited into flexibility units.

Information about flexibility units provides another layer of visibility – indicating how collections of devices have been aggregated into controllable resources. This provides richer information about behaviour and accessible response potential, which in turn depends on factors such as:

- technical potential (eg, aggregate size of EV batteries and capacity of chargers)
- contracted service levels (eg, how much the V2G service provider is able to draw on the controlled resources)
- behavioural effects (eg, expected portion of vehicles plugged in and available to respond).

Both of these information sets are useful for network planning (ie, projecting future demand to inform sizing and timing of investments) and operation (eg, scheduling outages and balancing loads).

Device-level information is potentially useful for service providers (or potential service providers) wanting to assess the potential size of the un-contracted resource.

Flexibility unit information may also be useful for distributors or Transpower (or retailers) seeking to contract for flexibility services. It provides richer information on how much capacity may be contractable in practice.

For more on commercial arrangements, refer **Appendix D**:

For case studies, refer **Appendix E**:

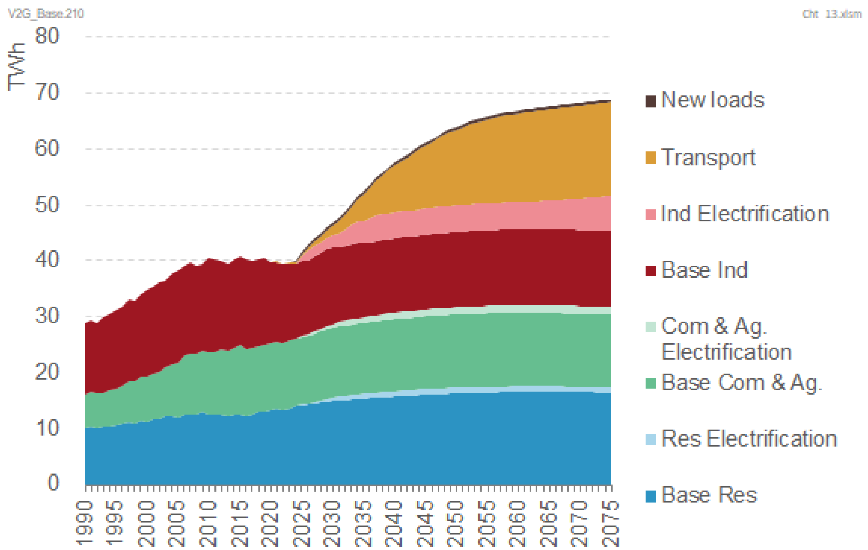
Appendix A. Value Opportunity

Appendix A provides more detail to support Chapter 2, which discusses value opportunity associated with V2G. It covers the following analyses:

A1. Electricity demand projections

The most significant element driving electricity demand growth from decarbonising New Zealand's economy is the uptake of EVs. Below, Figure 8 illustrates this significant energy increase from the uptake of EVs.

Figure 8: Base electricity demand projection



That said, there is a material degree of uncertainty about how quickly EV uptake will occur due to uncertainty over policies affecting EV uptake and over future changes in the relative costs of EVs and ICE vehicles. These uncertainties, when combined with uncertainty over factors such as population growth, results in a material range in EV-driven demand growth outcomes. However, as Figure 9 below shows, even in the low scenarios of EV demand growth, the extent of demand growth is still going to be significant.

Figure 9: Demand growth scenarios

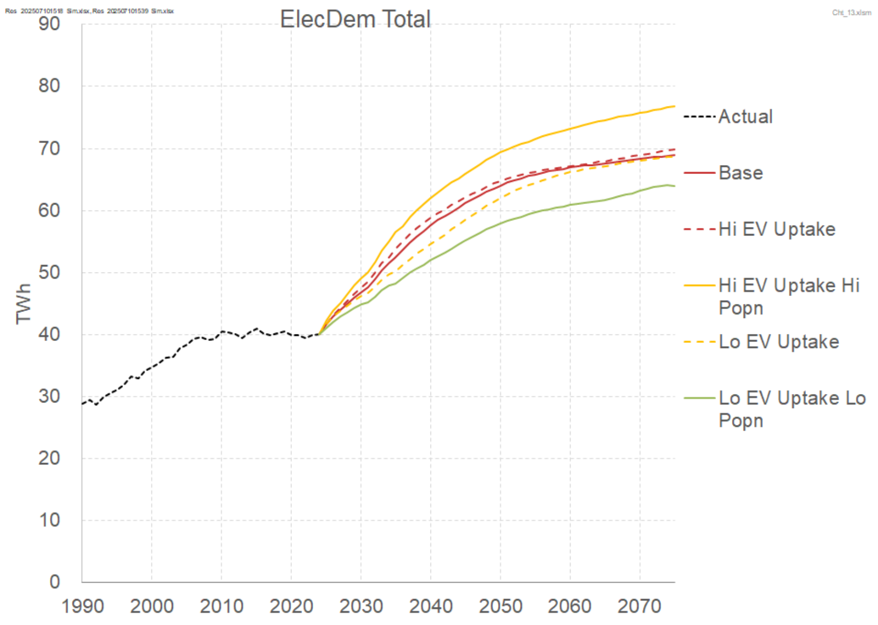
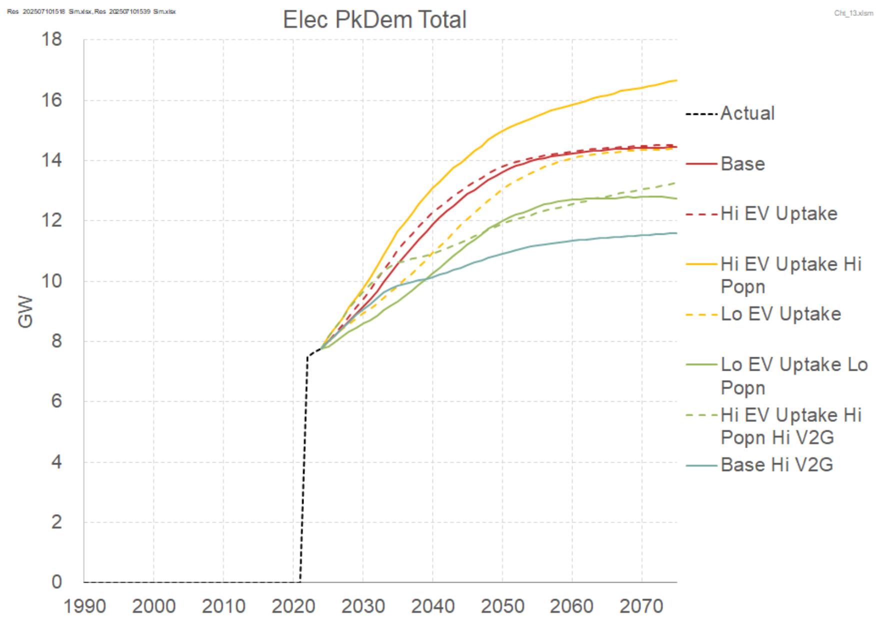


Figure 10 shows that the extent of peak MW demand growth is even more uncertain – in large part due to uncertainty over the extent to which V1G and V2G will increase peak demand.

We have a greater range of uncertainty in peak demand as there is additional uncertainty over the extent to which policies and other market arrangements will result in various appliances operating in a way that reduces peak demand – whether that be EVs via V1G or V2G, or other appliances such as hot water cylinders, heat pumps, and refrigerators, that can turn off for short periods of time during periods of high electricity prices.

The scenarios with a 'V2G' suffix have a low EV contribution to peak demand due to some combination of V1G and V2G, with the other scenarios having a high contribution to peak demand due to relatively 'dumb' EV charging without any material V2G.

Figure 10: Peak Demand Growth Scenarios

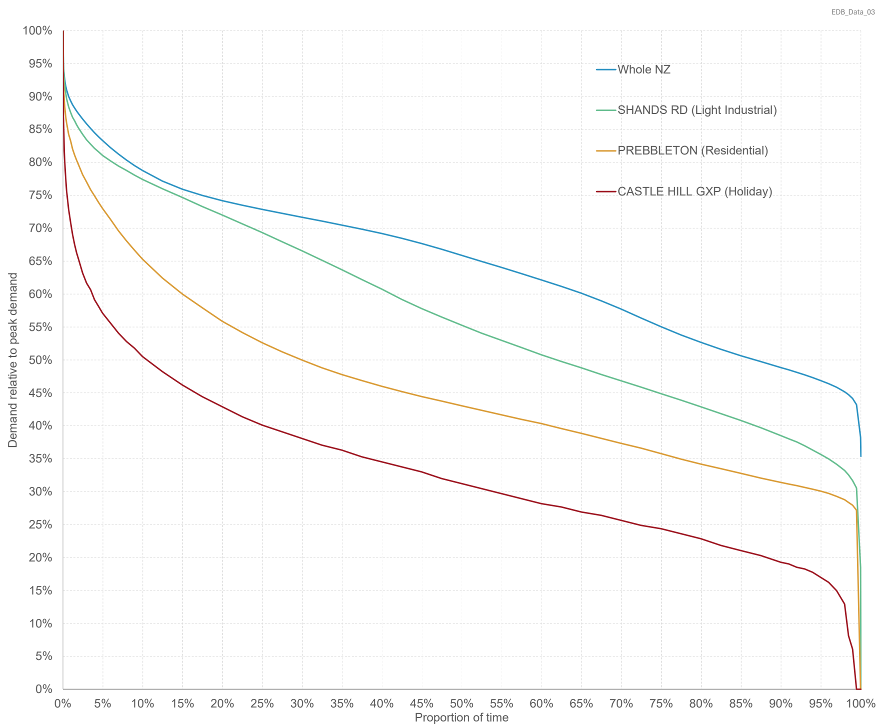


As can be seen, the analysis indicates that a future without smart V1G charging and V2G could have peak demand some 3 GW higher (approximately 40% of current peak demand!) than a future with such dynamic EV approaches.

Peak demand matters because a significant proportion of the cost of providing electricity relates to the costs of having sufficient supply capacity (both generation and network) to meet the relatively small periods of time of peak demand.

Figure 11 shows duration curves[11] of demand on a whole-of-NZ basis, and for three zone substations[12] on Orion's distribution network. On a national basis, almost 25% of generation capacity is required only 15% of the time, and demand sees more peak on a local basis. For a typical residential network, 40% of the capacity is only required for 15% of the time, and for a part of the network which has a very seasonal pattern of demand (eg, a holiday location), 55% of capacity is only required 15% of the time.

Figure 11: Demand duration curves



A2. Current fuel use and cost

According to oil statistics published by Ministry of Business, Innovation and Employment (2025), land transport fuel consumption in January 2024 totalled 187 petajoules (PJ). Petrol accounted for 83 PJ, with 60 PJ from regular petrol and 24 PJ from premium

11 A duration curve orders every demand from highest to lowest, with the x-axis showing the proportion of time that demand is higher than the demand at that point.

12 A zone substation is a transformer substation on a distribution network which takes very high voltage power and steps it down to a lower voltage to feed into the various homes and businesses located in that part of the distribution network.

grades, while diesel use was higher at 104 PJ. LPG contributed only a marginal 0.1 PJ.

The 187 PJ of liquid fuels consumed equates to an import cost of about NZD 4.4 billion. To obtain this figure we took the average international crude oil price in 2024 (around US $81 per barrel[13]), converting it into energy units (about 6.1 GJ per barrel). At an exchange rate of roughly 0.60 USD/NZD, this works out to about NZD 23 million per PJ, which multiplied by 187 PJ gives the reported value of approximately NZD 4.4 billion.

A3. Per-vehicle values

Our analyses has considered the benefits for different vehicle use cases, noting that the times when a vehicle is driven and when it is back at its base (home or business premises) will determine how much it can provide V2G services to the electricity system. We considered four very different use cases to understand the extent to which such variations in use would affect the V2G value:

- commuter car – a car that is used to commute to/from work during weekdays and is also used to travel for recreation and other activities at the weekends. The battery was assumed to have 60% of its usable capacity left on returning from its travels in the early evening[14]
- weekend-only car – a car that is parked at home during weekdays, and is only used to travel for recreation and other activities at the weekends
- delivery truck – a vehicle that is used extensively on weekdays – albeit returning earlier in the evening than the commuter car, but with 20% of useable capacity left – but is parked at the business premises during the weekends
- milk tanker – a vehicle whose within-year pattern of operation follows that of milk production on diary farms. All-day use on weekdays and weekends during peak milking periods (returning with 10% usable capacity left), falling to morning-only use on weekdays and weekends during ‘shoulder’ milking periods (returning with 55% usable capacity), and not being used at all during low milking periods.

Table 5.1 details the summary results of the value different vehicle use cases could achieve, *prior to assessing the potential effects of stationary batteries* – more on which later.

We have measured the electricity system value in $/kW/yr. This enabled comparison between use cases on a like-for-like basis.

The two right-hand columns have assumed typical kW injection capacities for the different vehicles which, when multiplied by the total $/kW/yr electricity system value, gives a total annual electricity system $ value from V2G expressed in dollars per year.

This shows the value is significant, ranging from almost $2,200 per year for a typical commuter car, to $25,000 per year for a milk tanker.

13 https://www.eia.gov/todayinenergy/detail.php?id=64304
14 Because battery manufacturers recommend that batteries are generally only charged to 80% of their nameplate capacity, and that batteries aren’t drained to below 10%, we define usable capacity as being 70% of nameplate capacity.

Table 5.1: Electricity system value from V2G - prior to stationary batteries[15]

	Electricity system value ($/kW/yr) Energy	IR	Networks	Total	Injection capacity (kW)	Value ($/yr)
Commuter car	130	15	150	295	7.4	2,175
Weekend car	210	15	150	375	7.4	2,775
Delivery truck	85	15	130	230	50	11,500
Dairy tanker	135	15	100	250	100	25,000

V2G_Misc_01

The value of providing V2G should, absent the effect of stationary batteries, outweigh the costs of equipment necessary to enable V2G:

- the cost of an AC charger for a light vehicle that has a grid-compatible on-board converter is approximately $1.5k – less than the projected annual electricity system benefit from V2G – and for a light vehicle that needs a DC charger, the DC charger cost is equal to about two-and-half years' worth of electricity system benefits
- for heavy vehicles such as trucks that will anyway need a DC charger, the incremental costs of a DC charger that is V2G compatible is low – potentially zero going forward as DC chargers are made fully V2G compatible as a matter of course.

Other insights include that the V2G value will vary between vehicle use cases, driven by:

- the pattern of operation of the vehicle – particularly when it is likely to be plugged-in at its base (home or business premises) and how full its battery is likely to be when it returns from its travel. In short, vehicles that are likely to be plugged-in during evening peak periods (particularly during winter weekdays) with a battery that is not too empty will deliver the greatest electricity system value from V2G
- whether the vehicle's base is a home or small business that is connected at the Low Voltage (LV) level, or a large factory that is connected at the High Voltage (HV) level. A vehicle connected at the LV level can potentially avoid greater network costs than one that is connected at the HV level.

The emergence of stationary batteries will likely reduce the revenue available for V2G – and vice versa!

The qualification above around "prior to stationary batteries", is because permanently installed batteries connected to the grid will perform fundamentally the same service as V2G. Such stationary batteries include:

- small household batteries, eg, the Tesla Powerwall with 13.5 kWh of storage
- EDB-owned pole mounted batteries connected to the LV networks with approximately 100 kWh of storage
- very large transmission-connected batteries, such as the 200 MWh batteries being developed by Contact, Genesis, and Meridian.

We estimated the current cost of grid-scale stationary batteries with two hours of storage capacity as approximately $750 per kWh of storage capacity and $1,500 per kW of injection capacity.[16] For household batteries, our estimate of current cost was approximately

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15 The wholesale value is the average value over the three years modelled (2028, 2037, and 2047) and assuming a vehicle can discharge for up to four hours if required – subject to the limitations of its use case as to the extent to which the battery is empty on returning from its travel.

16 Based on the $150m quoted cost for Genesis' 200 MWh / 100 MW battery. https://www.genesisenergy.co.nz/about/news/genesis-kicks-off-battery-construction-at-huntly-power-station

1.8 times as much on both a per kWh and per kW basis.[17] No cost estimates have been found for pole-mounted EDB batteries, but we assumed they were approximately mid-way between the two.

Table 5.2 below shows the annualised costs of these batteries – being the amount of annual revenue the batteries will need to earn to recover their costs – both now, and into the future assuming an average 2% per annum rate of cost reduction.[18]

Table 5.2: Estimated current and future stationary battery costs

	Storage ($/kWh/yr)			Capacity ($/kW/yr)		
	2025	2035	2045	2025	2035	2045
Grid-scale	100	82	67	200	163	134
Pole-mounted	140	115	94	281	229	187
Household	181	148	121	361	295	241

V2G_Misc_01

Table 5.3 below shows the potential value of stationary batteries calculated on the same basis as for the value of V2G shown earlier.

Table 5.3: Electricity system value of stationary batteries

	Electricity system value ($/kW/yr)			
	Wholesale	IR	Networks	Total
Grid-scale	135	15	20	170
Pole-mounted	135	15	130	280
Household	135	15	150	300

V2G_Misc_01

The significant difference in the network value between the different stationary batteries relates to where in the network they are connected.

Transmission-grid connected batteries can't avoid any distribution network costs, whereas pole-mounted and household batteries connected at the LV level can help avoid transmission costs and distribution costs.

One of the most significant takeaways from comparing the battery cost columns (on a capacity basis) in Table 5.2 with the electricity system values calculated on a capacity basis in Table 5.3, is that stationary batteries are very close to being cost-competitive today – i.e., the 2025 battery cost estimate is close to the electricity system value estimate.

With the projected reduction in battery costs, the cost of stationary batteries should be substantially less than the projected electricity system value. Thus by 2045, the cost of the batteries is projected to be $35/kW/yr less than the electricity system value for grid-scale batteries, $95/kW/yr less for pole-mounted batteries, and $60/kW/yr less for household batteries.

Therefore, batteries will become the marginal resource to perform the peaking service currently provided by other supply assets – the consequence of which is that the electricity system value of reducing peak demand through services such as V2G will fall to the level of the marginal cost of batteries.

Given that pole-mounted EDB-owned batteries appear to be the most cost-effective type of stationary batteries, this should reduce the value of providing V2G services set out in Table 5.1 by up to $95/kW/yr – i.e., by approximately 30 to 40%.

17 Based on a quote of $19,000 for a Tesla Powerwall 3, with 13.5 kWh of storage and 10 kW of injection capacity and factoring the cost of an expansion pack (without an extra inverter) to produce a similar 2-hour capability as grid-connected batteries.

18 The annualisation calculation assumes capital cost-recovery over 15 years using a pre-tax real WACC of 7%, plus annual opex equivalent to 2.5% of initial capex.

We expect this to manifest through changes to the wholesale energy and instantaneous reserves (IR) prices – i.e., a reduction in the within-day peakiness of energy prices and a potential complete collapse of non-peak IR prices. A complex relationship between wholesale and network prices arises as the avoided network costs will start to be the avoided costs of stationary batteries – less any wholesale arbitrage value.

Furthermore, we say "up to" $95/kW/yr because there is likely to be an additional dynamic that, as batteries start to shave peaks, the need to deliver additional capacity value will require batteries of progressively longer duration storage – i.e., moving from two hours to three, then four, etc. On a cost per kW basis, a four-hour battery is almost double the cost of a two-hour battery.[19]

While this will reduce the value which V2G could achieve, the low incremental cost of V2G means it should still be very cost-competitive against stationary batteries.

Indeed, the most likely factor determining the value that V2G can achieve is the extent of uptake of V2G itself! With low incremental cost and the potential for very large-scale uptake, V2G has the potential to completely displace stationary batteries – at least for the provision of wholesale energy and IR services, and potentially also for network services relatively 'high-up' in the voltage network. Sufficient diversity across EVs should provide the after-diversity confidence required by network operators that V2G will deliver the response required to meet peak capacity requirements.

A4. Household-level analysis

To understand the potential for V2G, it is useful to analyse the potential impact on household demand profiles of two key energy storage technologies – hot water cylinders, and EV batteries.

To consider this, we have analysed two points in time:

- 'Today', being a breakdown of electricity consumption between end-uses as per EECA's Energy End-Use Database[20]
- 'Electric 2050', being our modelling of the increase in average per household electricity consumption by 2050 assuming the broad degree of electrification proposed by the Climate Change Commission.

Key assumptions for the Electric 2050 are:

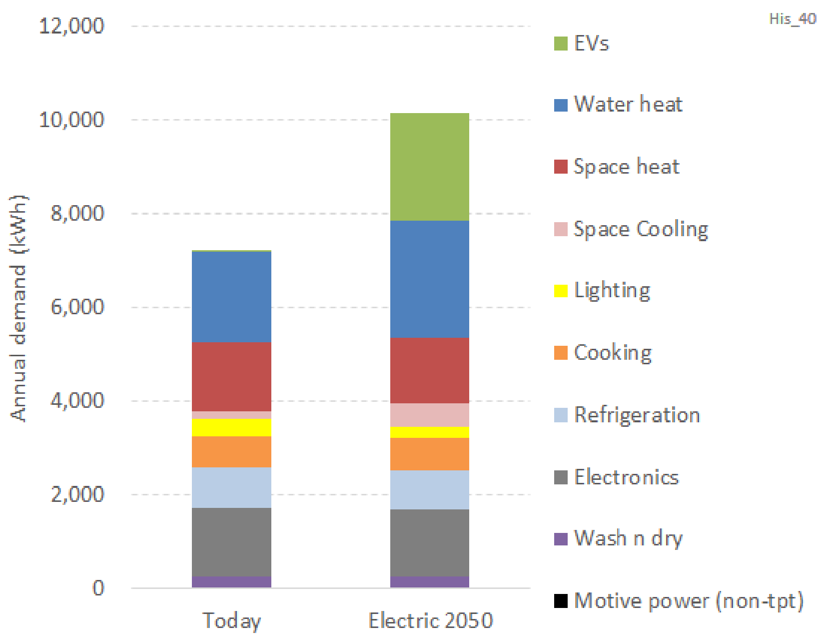
- household vehicles are all fully electric, and 30% of today's travel kms undertaken by private vehicles shift to active or public transport
- 90% of natural gas and LPG space heating load switches to heat pump electric, with the remaining 10% switching to resistance electric
- water heating all switches to electric, with 15% using heat pump cylinders (and the balance using resistive heating)
- gas and LPG cooking is all switched to electric; and

[19] Given savings in inverter costs, the four-hour battery is estimated to be approximately 1.85 times the cost of the two-hour battery.
[20] https://tools.eeca.govt.nz/energy-end-use-database/

- there are energy efficiency improvements across lighting (25%), space heating (15%), water heating (5%) and appliances (2.5%).[21]

Figure 12 shows the breakdown of average annual electricity consumption.

Figure 12: Breakdown of average household annual electricity consumption



Note: Residential 'Motive power (non-tpt)' is classed as 'recreational marine' in the EEUD. We have excluded this from the analysis of household energy demand

Figure 11 shows that by 2050, average per household annual electricity consumption could increase by 42% - from 7,170 kWh per household today to 10,160 kWh in 2050. The main contributors are from households switching from internal combustion energy vehicles (ICEs) to EVs, and the switch from gas and LPG to electric water heating.

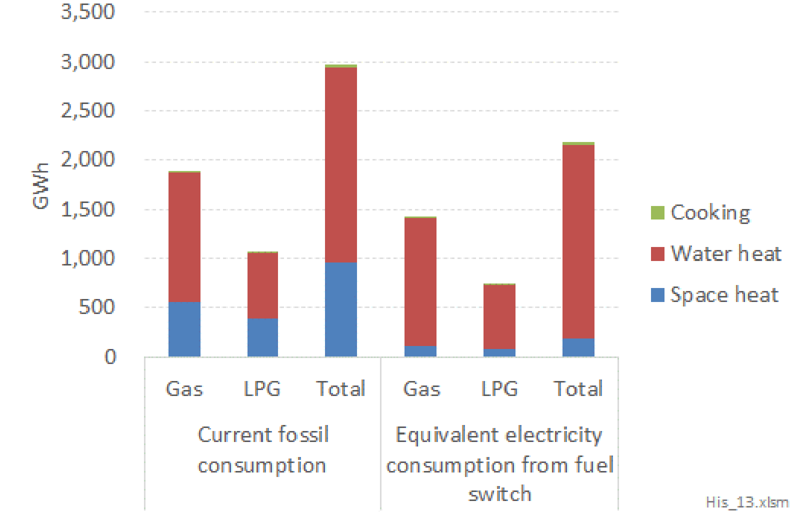
Box 1: Why is there no increase in space heating consumption?

Unlike the fuel switch for water heating, the switch from gas and LPG space heating does not cause a material increase in electricity consumption because, as shown in Figure 13 below, there is currently much less fossil-supplied space heating than water heating, and space heating heat pumps have very high

21 The space and water heating efficiency improvements are due to a combination of: improved insulation; heat pump efficiency improvements; and some switching from resistance electric to heat pump electric heating. These are likely to improve significantly faster for space heating than for water heating, in large part due to the significantly greater potential for insulation improvements. We have assumed an average annual rate of improvement in energy efficiency for space heating of just under 0.6%, and just under 0.2% for water heating. We understand these are consistent with the assumptions used by the Climate Change Commission for its projections.

efficiencies.[22] In addition, as detailed in footnote 21, it is assumed that efficiency improvements are likely to be much more significant for space heating efficiency than for water heating.

Figure 13: Current residential fossil gas consumption and electricity equivalent if fuel-switched by 2050



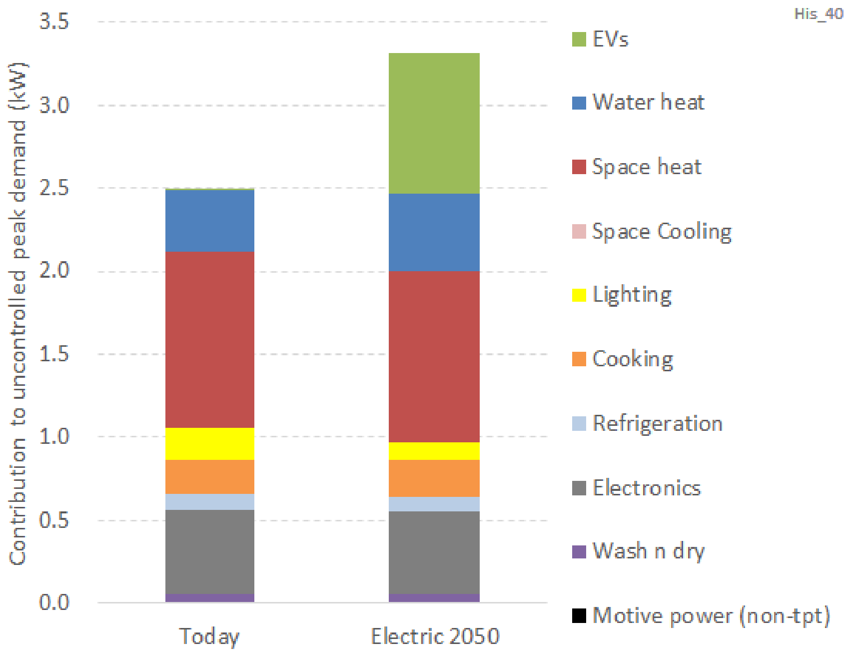
While the increased annual consumption shown in Figure 12 will certainly drive a need for more *energy* generation production, just as significant a cost driver is whether it also drives a need for more network and generation *capacity*. We will only see this if the increased consumption contributes to peak demand, as the peak demand is a significant driver of network and generations

Figure 14 shows our estimated breakdown of average per household contribution to peak demand *without* any demand management – i.e., prior to any appliance control or action by consumers to shift when they use an appliance.[23]

22 EECA's EEUD analysis assume space heating heat pumps have a coefficient of performance (COP) of 380% (i.e. for every 1 kWh of electricity they consume, they deliver 3.8 kWh of useful heat), compared with 78% for gas heaters. For our analysis, we have used a heat pump COP of 350%.

23 The estimates have been derived from within-year patterns of consumption from the BRANZ Household Energy End-use Project (HEEP) (https://www.branz.co.nz/environment-zero-carbon-research/heep/), combined with Concept estimates of within-day patterns of consumption informed by, amongst other things, an EECA-funded University of Otago hourly appliance monitoring study (https://cfsotago.github.io/GREENGridEECA/)

Figure 14: Breakdown of average per household contribution to peak demand prior to any appliance demand management



As can be seen, 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 we estimate that, if households have no incentive to manage when they charge their EVs, un-managed peak per household demand will increase by 37% - largely from EVs, with some increased contribution from water heating and small offsets from other uses. In total, EVs would represent 26% of un-managed peak per household demand.

Our estimate of EV-driven peak demand is based on modelling we undertook for a 2018 study on electric vehicle uptake.[24] We developed this from observed household within-day travel patterns and the distribution of journey distances. The 2018 report goes into the detail of the analysis, but the key take-away is that, despite people generally arriving home in the evening, there is significant diversity in:

- when they come home – this is typically spread over a period of many hours from the early afternoon to late evening; and
- how far their vehicle travelled during the day.

These sources of diversity mean that, despite EVs being charged at home at rates of between 2.3 and 7.9 kW[25], unmanaged EV charging will 'only' increase average the after-diversity household contribution to system peak demand in 2050 by about 0.9 kW. Our theoretical modelling was borne out in practice by the likes of Vector and Wellington Electricity in studies of actual home-charging behaviour.

But if consumers can be incentivised to charge their vehicle in a 'smart' fashion that largely avoids charging during system peak periods, this increase in peak demand and associated costs need not occur.

However, the potential to manage demand isn't limited to electric vehicles. In theory, consumers could potentially also manage when they use other end-use appliances. If the potential for demand

24 *"Driving change" – Issues and options to maximise the opportunities from large-scale electric vehicle uptake in New Zealand*, Concept Consulting, March 2018. Available for download here: https://www.concept.co.nz/updates.html

25 2.3 kW charging can be done via a standard 3-pin plug. 7.9 kW charging would require the installation of a fast-charging connection.

management is widely spread across all end-uses, it would suggest that whole-of-property tariff approaches (ToU or CPD) could be most appropriate for incentivising consumer demand management. However, if the potential for demand management is concentrated in just one or two end uses, it would suggest that 'type of use' or managed appliance tariffs could be most appropriate.

The extent to which different end-use appliances can contribute to peak demand management depends on:

- the size of the end-use's unmanaged contribution to peak demand – as set out in Figure 14 above
- the extent to which the demand is time critical.

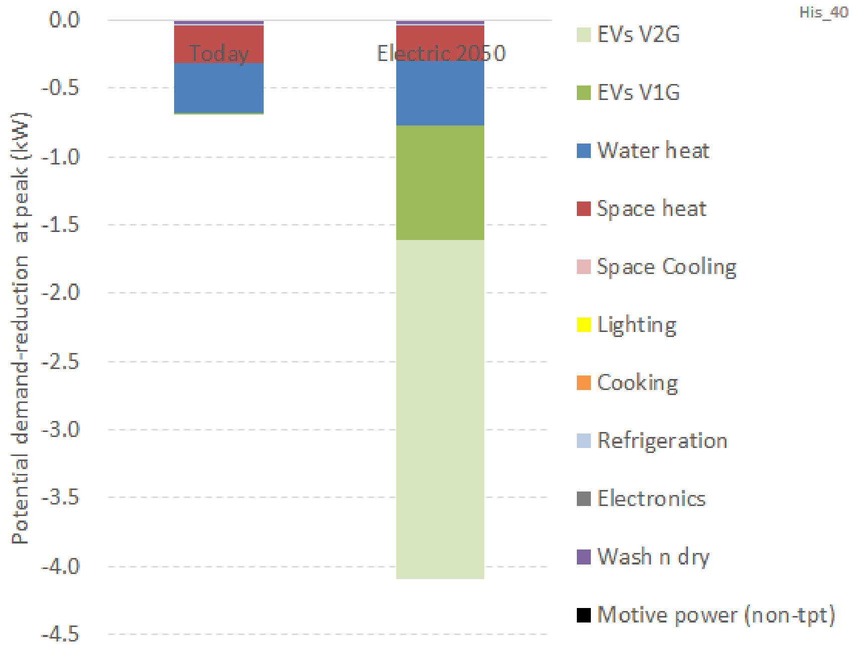
With regards to this latter point (ie, how easily the demand can be time-shifted away from peak periods):

- storage technologies (ie, hot water and EVs) have significant potential for demand to be reduced during peak periods, without materially affecting the energy service
- space heating and refrigeration have some limited potential, using the thermal mass of the house or fridge as the 'storage' mechanism. However, there are limits to the duration of such a reduction before the quality of service starts to be severely degraded – ie, the house starts to get too cold or the fridge too warm. Poorly insulated houses and fridges are particularly ill-suited to such load management
- wash 'n dry technologies (laundry and dishwashers) can be postponed to after peak periods to a certain extent
- other uses have very limited ability to interrupt / postpone without severely degrading the service (lighting, cooking, electronics).

In addition, EVs also offer the potential for the energy stored in the battery to be injected back *into* the grid through V2G.

Figure 15 shows an estimated breakdown of the potential for demand management, taking all these factors into account.

Figure 15: Breakdown of average household potential for appliance demand management during peak demand



The key takeaway is that EVs offer by far the greatest potential for load management, followed by water heating:

- Both technologies are large loads and are storage technologies. Therefore, they both can avoid charging during peak periods allowing for significant peak demand management – with this aspect for EVs being classed as V1G in Figure 15

- EVs also have the potential to inject power back into the grid – V2G in Figure 15. Crucially, electricity supply companies can call on this in times of system scarcity meaning diversity effects the drive peak demand don't affect the kW capacity of delivering The main limiting factor is whether a vehicle will be plugged-in at the time. For the analysis in Figure 15 we have conservatively assumed that only 20% of vehicles will be at their base and have a V2G capable charger during winter evening peaks. We have also assumed that the average V2G charger capability is 7.4 kW

Together, EVs and hot water account for over 90% of our assessed potential for flexibility from consumer appliances.

Space heating has much less potential due to constraints on the ability to turn off, or even turn down, the appliance without starting to materially affect the heating service. These constraints are particularly for periods longer than an hour, seen on our coldest days. The sustained load management for this drives network capacity requirements. For the analysis shown in Figure 15 we have assumed that dynamic demand management could result in a 25% reduction in space heating's contribution to system peak demand. We suspect this could be optimistic.

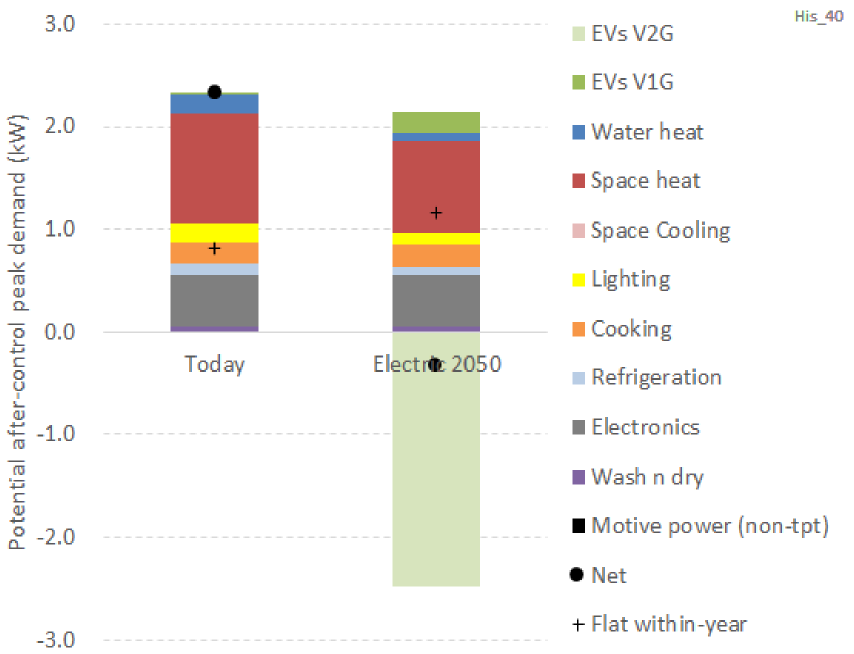
Refrigeration's potential is very small. In large part this is because, as shown in Figure 14 previously, it is not a big driver of peak demand. Thus, although refrigeration's annual consumption is roughly half that of space heating, its contribution to peak demand is only 8% that of space heating. This is because space heating demand is heavily concentrated in peak periods, whereas refrigeration demand is basically 'flat' throughout the year. Further, like space heating, refrigeration is likely to suffer constraints on the ability to control load for a sustained period on the coldest days that drive network capacity requirements.

A significant proportion of washing and drying peak demand could potentially be avoided by delaying turning on such appliances until after peak demand periods – we have assumed 40% reduction for Figure 15. However, their absolute contribution to demand reduction is relatively limited because the appliances are not large contributors to uncontrolled peak demand.

There is little or no ability to control lighting, cooking, and home electronics without causing significant disruption and inconvenience to households.

In Figure 16, we combine our analysis and demand growth and controllability to show a breakdown of peak demand with the maximum potential for load management utilised.

Figure 16: Breakdown of average per household after-demand management contribution to peak demand



On a simple analysis, it may appear that using the full potential of demand management and V2G could reduce the average household contribution to peak demand from around 2.2kW to *negative* 0.3kW. However, this is less than the 1.2kW demand that would occur if household energy use were completely flat across the year. As such, such outcomes at peak will not occur. Rather, the analysis indicates there is considerable potential to reduce peak demand to significantly flatten the overall shape of demand.

Furthermore, the analysis does clearly highlight that the potential for demand management is dominated by just two technologies: EVs and hot water control. Taken together, these would more than satisfy the need for peak demand management, without needing to call on other technologies.

What about household solar and batteries?

The analysis above doesn't consider the potential contribution from household solar and batteries.

In theory, these could make significant contributions to altered household demand and provision of flexibility. However, we note the following points:

- residential rooftop solar can reduce average annual net consumption, but makes no contribution to flexibility because system demand peaks occur on the coldest winter evenings when solar output is effectively zero
- our evaluation is that residential rooftop solar is fundamentally uneconomic because it is significantly more expensive than utility-scale solar, which benefits from:
  - significant economies of scale
  - a far superior ability to use axis tracking or optimised angles of inclination to optimise scheme output to periods of greatest value.
- also, solar (whether residential or utility) has the potential to become a cost *driver* independent of the traditional demand drivers if penetration becomes high enough to reverse electricity flows (and therefore causing stress on the network, requiring upgrades)
- our evaluation is that household-scale static batteries are also less economic than utility-scale batteries, which benefit from:
  - economies of scale
  - the ability to locate (and relocate) relatively small quantities of utility batteries in locations that optimise network investment deferral benefits
- also, well-managed EVs and hot water can deliver the same benefit as static batteries (whether household or utility-scale) at much lower incremental cost.

Taken together, it is difficult to estimate the potential from technologies that are uneconomic relative to alternatives.

That said, the uptake of these technologies is indicative of the need for tariff reform, as the traditional tariff structures incentivise households investing in uneconomic solar plus (in some cases) batteries.

This is not a good outcome from both an economic and environmental perspective, as the type of non-cost-reflective tariffs which incentivise household solar uptake will *dis*-incentivise EV uptake. This situation is being resolved as distributors transition toward tariffs with a higher fixed component and very low (or zero) off-peak usage components.

A5. Power system benefits analysis

The generation supply/demand balance can vary significantly across a day and year due to:

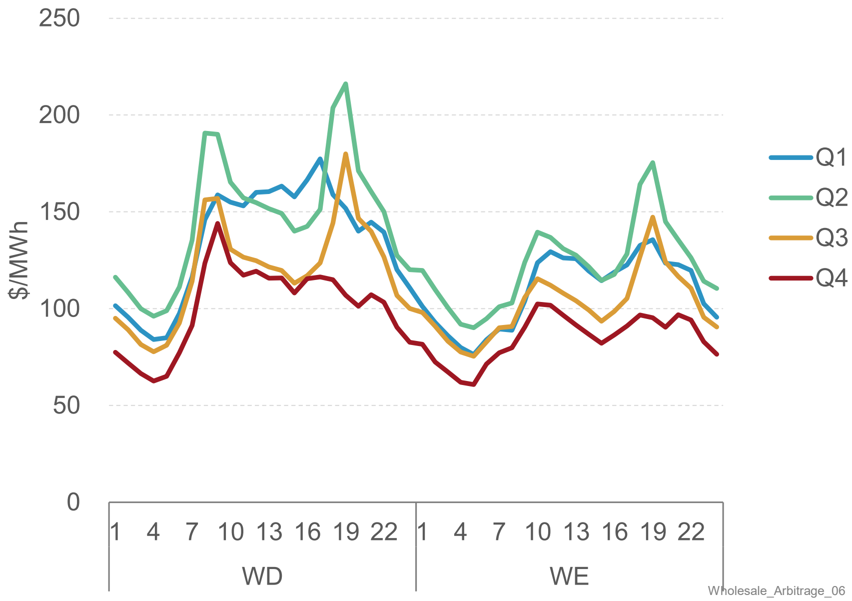
- variations in demand

- variations in supply – particularly variations in renewable output from hydro, wind, and solar.

At times when demand is relatively high compared to supply, there is a need to call upon more expensive sources of generation, and vice versa when there is a relative surplus in the supply / demand balance. This variation in the costs of generators needing to be called upon flows through to variations in prices.

As well as there being a general seasonal pattern to prices (higher in winter, lower in summer), there is also a general diurnal pattern to prices (lower overnight, highest in morning and evening times, lower in weekends (WE) than weekdays (WD)). This is illustrated in Figure 17, which shows average within-day prices at the reference Otahuhu node in Auckland for each of the four quarters for the period 2000 to 2024, inclusive.

Figure 17: Average historical prices (Real, $2024)



The within-day variation in prices creates an arbitrage opportunity for EVs: seeking to charge in predominantly lower-priced periods and injecting back (V2G) at higher-priced periods.

Modelling was undertaken which explored the net revenue a vehicle with V2G capability might earn from operating in the energy market.

The model considered how a vehicle with V2G capability might operate for different potential future days.

Each day was represented by a 24 hr time series of prices.

For a given day, the model calculated the value from injecting power in the top 'x' hours of the day, and the subsequent increase in cost from having to re-charge in the following hours – additional to the re-charging the vehicle would anyway have to do having been driven during the day. The model assumes that any V2G injection will have to be re-charged by 6am the following day.

Different vehicle operating patterns were considered, as represented by:

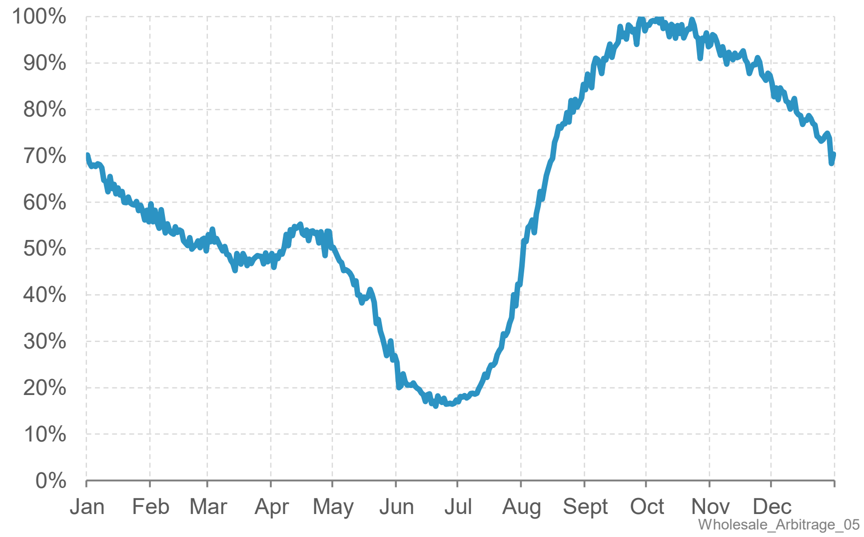
- the time of day when the vehicle returns to its 'base' (home or business premises) after a day's travel. Thus, V2G can't occur before this time.
- the amount of remaining battery charge when it returns to base – which then determines how long the vehicle can inject power into the grid, as well as how much charging it needs to do just to return the vehicle to full battery prior to any V2G.

Distinction was made between weekday and weekends, to enable consideration of vehicles such as commercial vehicles that may have very different patterns of travel between these two-day types.

A number of different vehicle use cases were considered:

1) 'Commuter car' where the vehicle returns at 6pm on weekdays with a 60% full 'usable' battery capacity.[26] At weekends it returns at 4pm, also with 60% remaining of its usable battery capacity
2) 'Weekend car' where the vehicle is assumed to not be used during weekdays (ie, has 100% of its usable capacity that can be used for injection at any hour of the day). At weekends it returns at 4pm, with 60% remaining of its usable capacity
3) 'Delivery truck' which returns to base at 4pm on weekdays with 20% remaining of its usable capacity, and is not used at all at weekends (ie, has 100% of its usable capacity that can be used for injection at any hour of the day)
4) 'Milk Tanker' where the time of day when the vehicle returned to base and the amount of remaining battery charge varied according to the pattern of milk production throughout the year. Thus, at times of very low milk production the vehicles are assumed not to be driven at all, enabling batteries to be employed for V2G opportunities at all times of the day. At times of high milk production, the vehicles are assumed to return to base relatively late in the day (6pm), and only have 10% usable capacity when they return. During 'moderate' levels of milk production, the vehicles are assumed to return to base at 1pm and have 55% usable capacity on their return. Figure 18 shows the assumed within-year pattern of milk production.
5) 'Stationary battery' which is not a vehicle at all but, for comparison purposes, shows the revenue that could be earned by a stationary battery which is plugged into the grid constantly.

Figure 18: Modelled pattern of milk production[27]



For each of the different V2G use cases, we modelled potential different approaches to V2G operation:

- specifying a maximum number of hours that V2G could operate in a day. We looked at the effect of allowing 1 hour V2G operation in a day up to 4 hours V2G operation in a day –

26 Because charging a battery regularly to 100% of capacity can degrade its performance, vehicle manufacturers recommend only charging up to 80% of a battery's capacity for the majority of the time. Likewise, they recommend not letting the battery fall below 10% of charge if it can be helped. Accordingly, we define a battery's usable capacity as being between 10% and 80% of its nameplate capacity – ie, 70% in total.

27 The pattern was based on the average within-year gas demand for Fonterra's milk processing sites for the period 2018 to 2024, inclusive.

subject to having sufficient remaining battery charge after returning to base. The number of hours of operation is a function of the kWh capacity of the battery versus the kW injection capacity. For example, an Ioniq 5 has a 63 kWh battery. If the usable capacity is 70% of this value (44.1 kWh), and a wall charger has a capacity of 7.4kW, the battery could discharge for a maximum of 6 hours in a day if the battery was charged to the maximum of its usable capacity. If it was only at 60% of its usable capacity (26.5 kWh) it could only discharge for a maximum of 3.6 hours in a day

- only calling upon V2G if prices rise above a threshold value, with the threshold being specified in terms of the Xth percentile of all prices in the price series. This is to consider the extent to which value is reduced if operation is limited to the top 'x' hours of high prices.

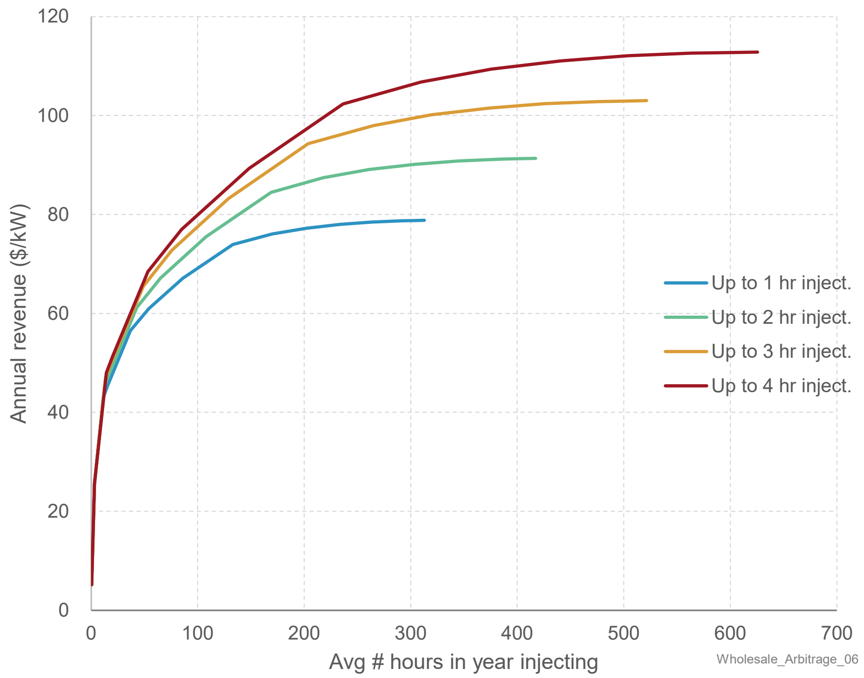
We modelled the operation of these vehicles across the full range of expected prices ,because there is considerable variation in prices on a within-day, within year (due to seasonal and weekday/weekend effects), and year-to-year (due to dry/wet year dynamics) basis. Accordingly, a given 'year' isn't just represented by 8,760 hours, but a greater number reflecting the range of possible 'weather years'.

For future years, we have drawn upon the projected price series produced by Concept's proprietary electricity market forecasting model, ORC.[28] ORC models each future year across 43 weather years – giving a total of 376,680 hours modelled for a given future year. We modelled different future years to reflect variations arising from factors such as increasing proportions of renewables in future years, and increasing EV demand, which is expected to significantly increase evening demand.

Additionally, we modelled a price array of the historical prices that have been experienced for the period 2000 to 2024 inclusive – all inflated by the relevant CPI to be in $2024.

Figure 19 shows a graphical representation of the results for one vehicle use case (Delivery truck) for one future wholesale price series (2037). The value is expressed in $/kW/yr. Thus, if a value is 100 $/kW/yr, and a Delivery Truck has an ability to inject 20 kW into the grid for the number of hours specified, it could earn $2,000/yr.

Figure 19: Variation in V2G revenue with different modes of operation for Delivery Truck pattern of operation using modelled 2037 wholesale price series



28 Details of our electricity price forecasting service can be found here: https://www.concept.co.nz/electricity-price-forecasts.html

One of the key takeaways from this analysis is that a significant proportion of the value is in the top few hours of operation each year. This results in diminishing returns from injecting for progressively greater numbers of hours each year – as reflected by the reducing gradient of each of the lines, and by the reducing incremental value by moving from up to 1hr injection to up to 2hr injection, and from up to 2 hr injection to up to three hour.

This is further illustrated by Figure 20 which shows how the daily revenue from V2G varies between the 365 days in an 'average' year, with the subsequent figure, Figure 21, 'zooming in' on the left-hand side of Figure 20's x-axis to only show the top 5 days in a year.

Thus, the vast majority of days earn nothing from V2G, but a few earn much greater amounts, with the peak day earning $16/kW.

Figure 20: Variation in daily V2G revenue across an 'average' year

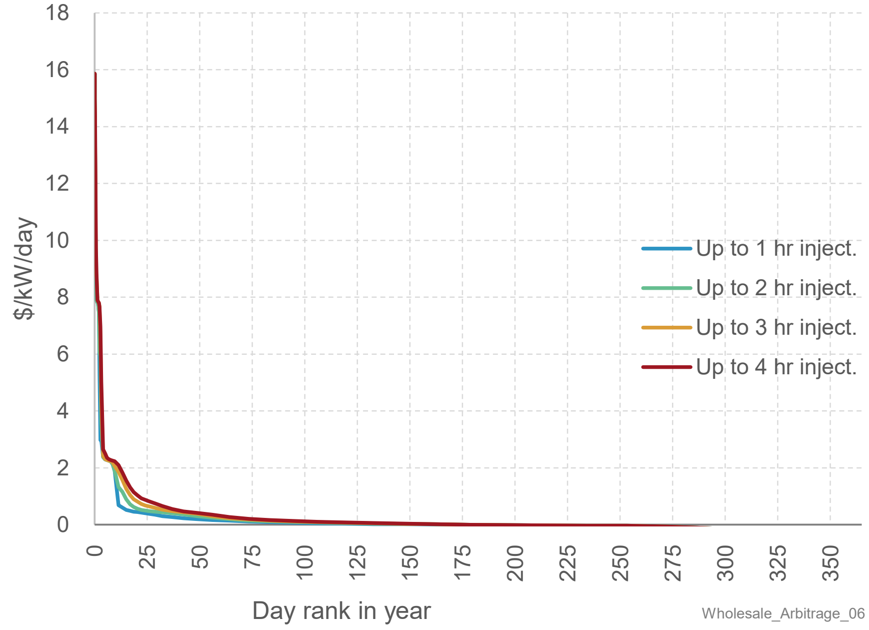
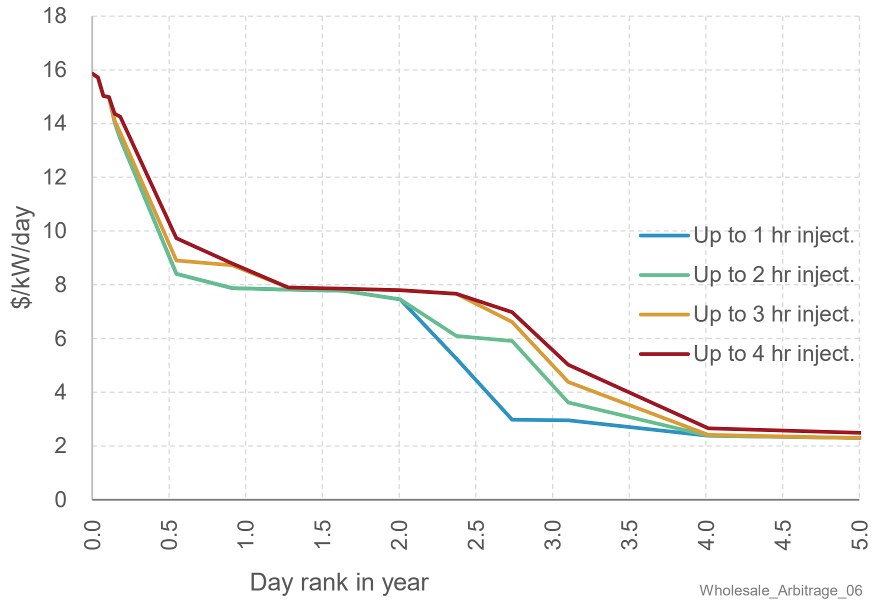


Figure 21: Variation in daily V2G revenue across top 5 days in an 'average' year



The emphasis of the word 'average' is because there is significant year-to-year variation between years. Figure 20 indicates that a lot of the value is in the top 0.2 'days' in a year.

Thus, the value from V2G is principally from a relatively small number of days where the market is experiencing significant price stress due to exceptional supply/demand imbalances. These won't occur to the same extent every year but will be due to extreme weather events (e.g., extremely dry conditions coinciding with periods of non-windy weather) or other supply interruptions (e.g., as has happened with gas supply interruptions, or the failure of a major thermal power station).

This dynamic of value being concentrated in a relatively small amount of time is further illustrated in Figure 22 which shows the market price duration curve across several different wholesale price projections.

Figure 22: Price duration curves – LOG SCALE (Real, $2024)

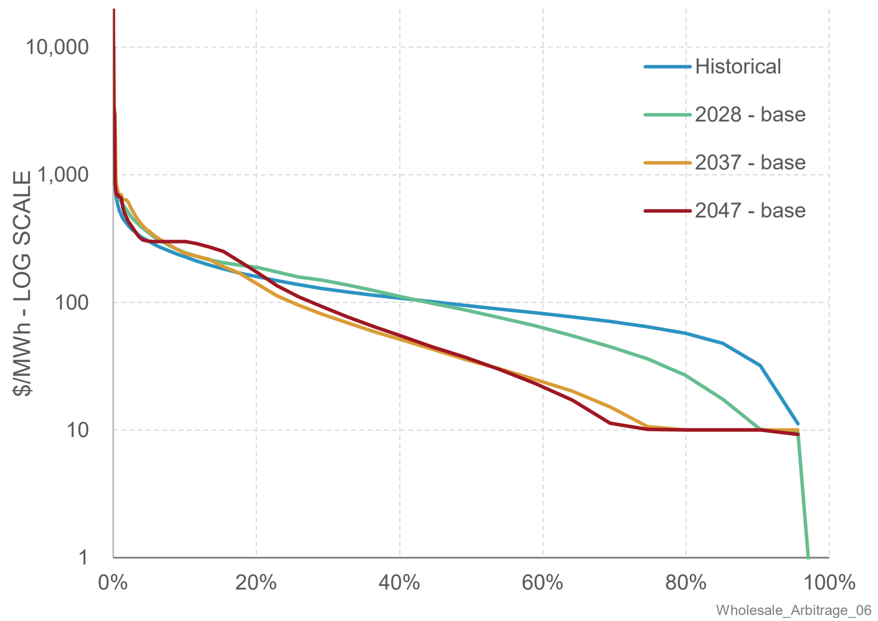


Figure 23 illustrates this further, showing the duration curve just for 2037 plus showing the cumulative value across the prices. This shows that approximately 58% of the value will come from just 10% of the time periods.

Figure 23: Price duration curve for 2037 - base scenario

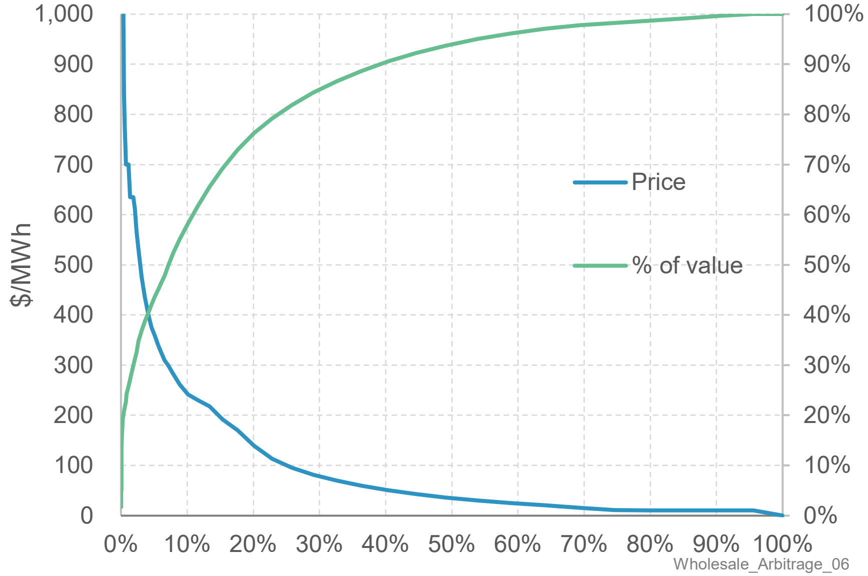
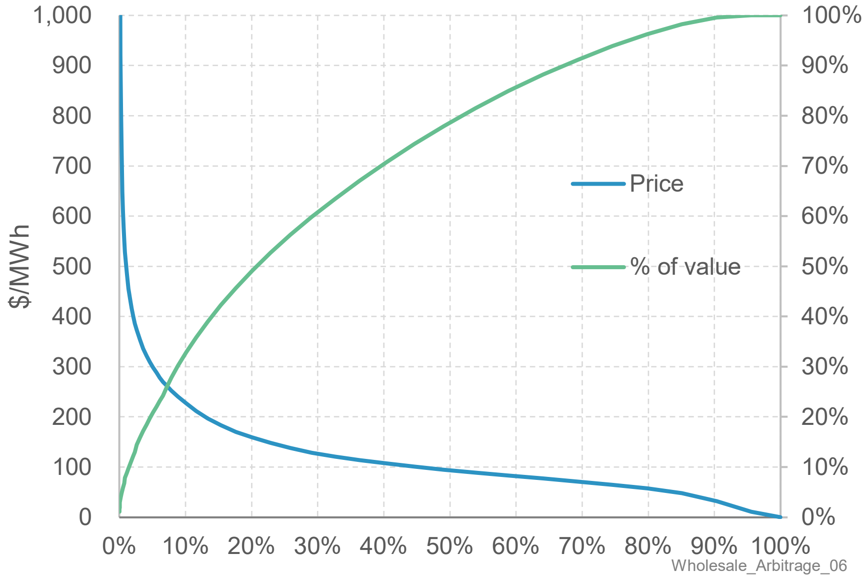


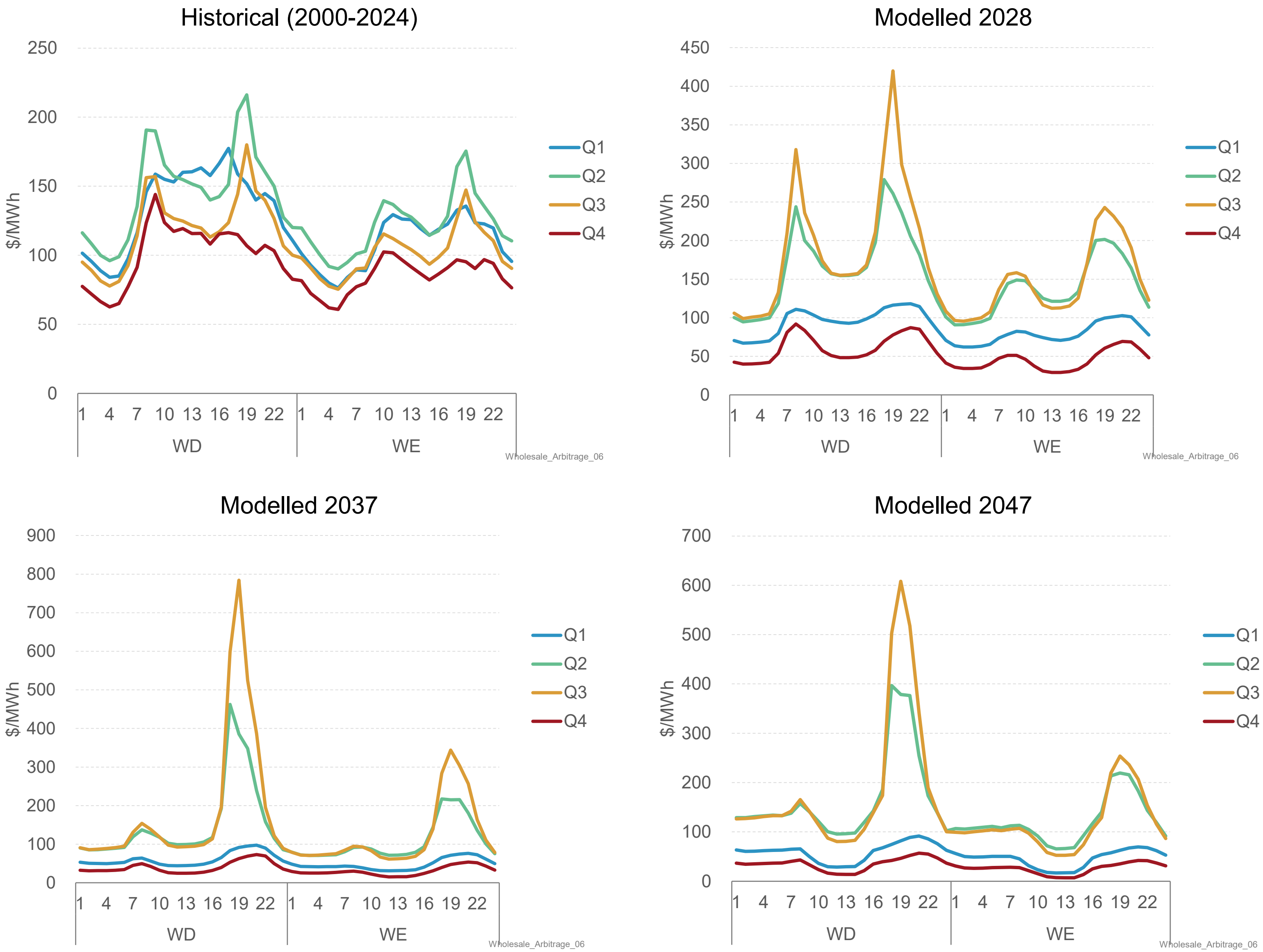
Figure 24: Historical price duration curve for 2000-2024 (Real, $2024)



Comparing Figure 22 and 23 shows us that future prices are projected to be significantly peakier than the historical price series.

Figure 24 also illustrates this idea through showing the average within-day and within-year shape of prices for different price series.

Figure 25: Within-day and within-year shapes of prices



The projected change in price shape is due to two factors:

- greater proportions of solar on the system. This will tend to suppress mid-day prices and summer prices relative to other time periods
- significant growth in EV demand. Given that most vehicles will return to their base at mid-afternoon / early evening, the re-charging demand will be most heavily concentrated in the subsequent evening periods, giving rise to much higher demands in these periods – at a time when solar, which is projected to grow significantly on the system, is not generating.

It should be noted that our modelling of electricity prices does allow for a reasonable amount of smart EV outcomes (shifting charging away from peak periods), and for batteries to be built to arbitrage the within-day variation in prices. Nonetheless, we are still projecting a significant growth in evening peak prices in the winter months.

The peakier prices for 2028 relative to history is because the system is projected to still be short of capacity relative to the more balanced supply / demand situation that was experienced for the majority of 2000-2024.

Table 5.4 on the next page shows the final results for all the different wholesale price scenarios, and V2G use case scenarios (vehicle type, and different limits on how often V2G is used).

The results are shown in $ per kW of injection capacity. This is to allow for comparison between use cases on a normalised basis.

These $/kW/yr values should be multiplied by the injection capacity of the vehicle to calculate the expected annual wholesale revenue from providing V2G.

For example, using the 2037 wholesale price array in Table 5.4, a commuter car with an injection capacity of 7.4 kW could earn ≈ $1,300 a year (175 $/kW/yr x 7.4 kW), whereas a milk tanker with a capacity of 100 kW, could potentially earn ≈ $17,000 a year.

The value for vehicles with higher or lower injection capacities will scale linearly with the injection capacity – noting that higher injection capacities will reduce the total number of hours the vehicle can inject in a day.

Table 5.4: Modelled V2G value for different scenarios ($/kW/yr)

		Limit to top 50 hrs in yr				Limit to top 200 hrs in yr				No limit			
Price scen	Use case	Up to 1 hr/day	Up to 2 hr/day	Up to 3 hr/day	Up to 4 hr/day	Up to 1 hr/day	Up to 2 hr/day	Up to 3 hr/day	Up to 4 hr/day	Up to 1 hr/day	Up to 2 hr/day	Up to 3 hr/day	Up to 4 hr/day
Historical	Commuter car	12	14	14	14	19	24	24	24	19	30	32	32
	Weekend car	20	25	27	28	30	42	47	51	30	51	65	76
	Delivery truck	12	14	14	15	20	23	24	26	18	24	27	31
	Dairy tanker	14	18	18	19	24	28	31	33	19	31	35	38
	Static battery	20	26	28	29	31	46	51	54	32	55	72	87
2028 - base	Commuter car	24	28	28	28	41	51	54	54	46	78	89	89
	Weekend car	31	36	37	38	49	63	71	74	55	94	125	148
	Delivery truck	21	22	22	22	35	39	41	42	38	47	55	61
	Dairy tanker	25	30	32	33	38	50	56	60	40	64	79	89
	Static battery	31	37	38	38	50	65	73	76	57	98	135	164
2037 - base	Commuter car	70	93	97	97	90	132	140	140	93	156	175	175
	Weekend car	72	95	108	116	95	138	164	179	98	166	220	258
	Delivery truck	60	63	66	67	77	86	94	97	79	91	103	113
	Dairy tanker	61	82	89	93	76	113	130	138	77	125	152	170
	Static battery	72	95	109	117	97	141	168	184	101	171	233	281
2047 - base	Commuter car	45	69	77	77	63	92	100	100	65	113	131	131
	Weekend car	49	72	94	102	72	104	128	137	76	134	187	217
	Delivery truck	39	41	43	44	56	64	69	71	57	69	79	86
	Dairy tanker	41	63	79	85	56	90	108	114	57	99	130	145
	Static battery	50	73	95	103	76	108	133	142	80	143	204	242

Wholesale_Arbitrage_06

Modelling validation and sanity-checks

The stationary battery results allow for a sanity check of the modelling. This is because our price forecasting model allows for optimal planting of stationary batteries (along with optimal planting of generation) to meet projected demand in a least-cost fashion. It does this for the period from 2032 onwards. The optimisation predominantly plants two-hour batteries – but limited to 1.5 cycles a day, with a required cost recovery of approximately $145/kW/yr in 2037 and $120/kW/yr in 2047. This is broadly consistent with the above results for the stationary batteries for between 1-2 hours operation a day, indicating the V2G modelling approach is reasonable.

This also enables consideration of another way of thinking about the likely future value to be achieved from V2G. The cost of the marginal resource that could perform such within-day flexibility will likely set the upper limit for what can be earned by other resources that can perform this within-day arbitrage.

In this respect, if static grid batteries can earn significant revenue from avoided network upgrades, their required earnings from the wholesale market will be less – noting that our price forecasting planting model doesn't currently assume material network cost avoidance revenue in determining their wholesale revenue recovery requirement.

For example, if such batteries being built in 2037 can earn $50/kW/yr, say, from avoided network costs, their wholesale market revenue recovery requirement will fall to $95/kW/yr. The subsequent increase in the number of batteries relative to a world where they can't achieve material revenue from avoided network costs, will act to progressively reduce the within-day price differentials until, on average, the differentials will be at a level that support a battery with a $95/kW/yr revenue requirement.

Furthermore, if V2G becomes relatively cheap to implement and ubiquitous, - noting that the scale of forecast capacity indicates a huge potential collective 'NZ battery on wheels' - the price differentials will collapse further.

To the extent that such futures eventuate, the achievable earnings for all the different vehicle types and V2G use cases in Table 5.4 should all fall proportionately to the reduction in earnings achieved by the stationary battery.

Another sanity check is that it should be noted that our price forecasting model also builds new gas-fired peakers, even though the carrying cost of such peakers ($140/kW/yr) is greater than the cost recovery of batteries (≈$120/kW/yr in 2047). This is because the gas-fired peakers are performing different flexibility duties to batteries – in particular longer-duration flexibility ranging from within-week, to seasonal, to year-to-year.

A notable quirk of the analysis is that the Commuter Car use case does not earn any additional revenue when the available V2G window is extended from 3 to 4 hours per day. This occurs because the scenario assumes vehicles retain only 60% of usable capacity at the end of each travel day, which in practice limits V2G availability to around 2.4 hours.

A6. Distribution network benefits

The demand-driven component of distribution network costs principally relates to having sufficient network capacity to meet periods of peak demand.

From the analysis set out below, we have estimated the demand-driven costs of distribution networks to be approximately $132/kW/yr.

In other words, in the long run, the costs of each extra MW of peak demand on a distribution network will result in an increase in costs of: 1 MW x $132/kW/yr = $132,000/yr.

This represents the value that could be achieved if V2G were able to reduce the average peak MW demand on a sustained basis.

The derivation of this $132/kW/yr value is as follows.

The annual Commerce-Commission reported non-Opex revenue requirement was summed across all EDBs for each year from 2013 to 2024, inclusive. Ie, the annual revenue for a year less the Opex spend for that year.

This covers the return on capital, return of capital (ie, depreciation) and tax cost for a distributor's asset base. Depreciation reduces the asset base, while capital expenditure adds to the asset base. The asset base is revalued annually for inflation, with an offsetting adjustment to revenue. This captures the accumulated impact of all capital spend not recouped through up-front contributions (ie, capital or in-kind contributions), including:

- the portion of new connection costs not recovered up-front
- building new network capacity to meet system growth, including due to connection growth or growth in per-connection peak demand
- renewing / replacing existing network assets that have reached the end of their economic life
- other capital investments, including re-locating network assets, reliability/safety/environment costs, and non-network assets

For each historical year the values were adjusted for CPI so that all values are in 2024-dollar terms.

These annual capital costs were divided by the sum across all EDBs of the reported peak demand values for each year. The average across the resultant $/kW values for each of the twelve historical years is approximately $240/kW/yr.

This represents a reasonable first-order estimate of the annualised capital costs of an 'average NZ' distribution network built to meet current levels of average consumer peak demand.

However, not all of the costs of building a network are driven by the level of demand. A significant proportion of the costs are independent of demand.

For example, the costs of poles or trenches are driven by the km of coverage, not by the MW capacity of the lines run along such poles or trenches.

Likewise, there are fixed costs associated with transformers and lines, such that the costs of such assets do not scale directly in proportion to their MW capacity plus, in the case of lines, km coverage is also a significant driver.

In this respect, $/kW is just one metric to consider the costs of electricity networks. Equally, $/km is another useful metric, or $/ICP. All are useful metrics, but none are complete explanatory metrics of the drivers of network costs.

Orion has undertaken analysis[29] estimating that approximately 55% of the capital costs of their network are driven by peak demand

[29] Taken from Table 24 of 2025 pricing methodology found here: https://www.oriongroup.co.nz/assets/Our-story/Pricing/Orion-pricing-methodology-2025.pdf

(39% system peak demand, and 16% local peak demand for individual LV networks).

Assuming this 55% is broadly representative of the extent to which NZ distribution networks are driven by demand, multiplying the $240/kW/yr figure by 55% gives a value of $132/kW/yr.

A couple of cross-checks have been performed to determine whether this value is likely to be broadly representative.

1) the equivalent value for Orion's network is $140/kW/yr. This takes their quoted $102/kW/yr for system peak-driven long-run costs, and scales this up to account for the local peak-driven costs quoted by Orion
2) the annualised $240/kW/yr cost was converted into an up-front cost of $3,704/kW. This 'de-annualisation' assumed that average network capital costs were annualised over a 45-year life using a 6% real discount rate (giving a 6.5% annualization factor). This $3,704/kW compares with a quoted replacement cost per kVA of $3,228 from Orion.

These cross-checks suggest that the value is broadly representative.

It should be noted that the cost of building a network is likely to be different for different network situations. Thus, relatively higher levels of network undergrounding, or relatively fewer ICPs per km of network, is likely to increase the cost of building a network to meet the average per kW demand for that network.

Conversely, networks that have lower levels of undergrounding, or more ICPs per km of network, will tend to have lower $/kW costs. This is illustrated by Figure 26 and Figure 27 showing the variation between networks of the average non-opex revenue on a per peak kW and per km basis, respectively.

Figure 26: Average non-Opex revenue per peak kW

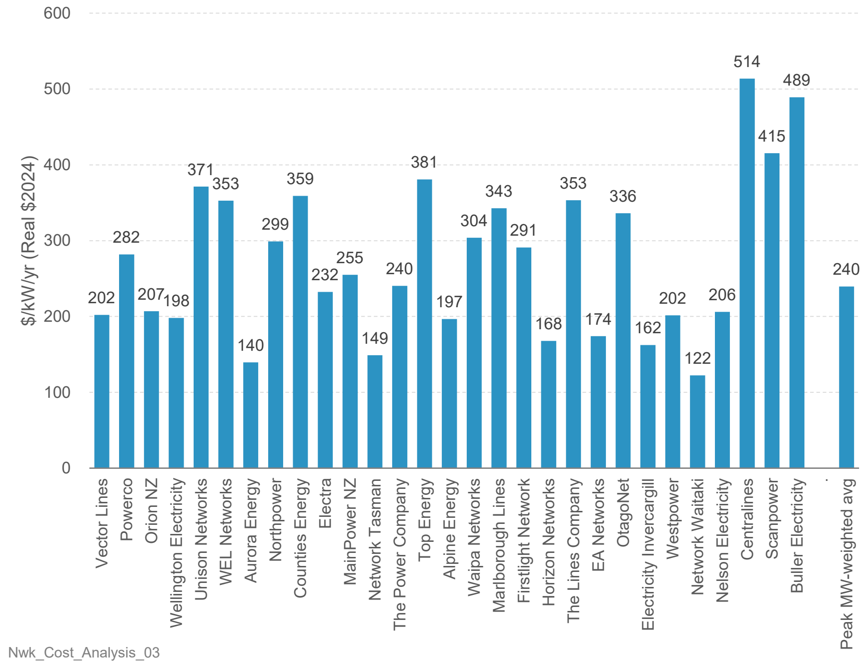
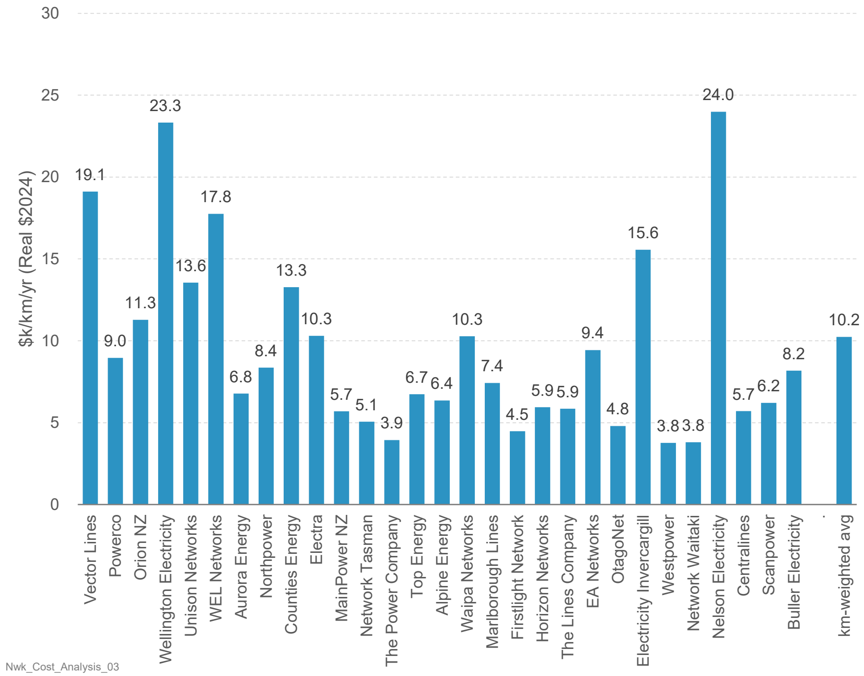


Figure 27: Average non-Opex revenue per km



The variation seen between networks is driven by their particular circumstance. The *demand-driven* components of such costs may not vary by as much. In other words, a dense network with relatively little undergrounding may have the *proportion* of costs driven by demand being higher than 55%, whereas a sparse network or one with higher levels of undergrounding may have the *proportion* of demand driven costs being lower than 55%, but the *$/kW* value of the demand-driven component of costs may be much more similar between networks.

This is because the demand-driven component of costs principally relates to the sizing of transformers and the capacity of lines, the variation of which with size is broadly the same across networks, whereas the costs of the infrastructure in which to install these assets varies much more significantly across network situations.

Based on all of the above, it is considered that $132/kW/yr is a reasonable estimate of the average distribution network costs of peak demand.

A7. Transmission network benefits

A similar exercise has been undertaken to evaluate the likely costs of peak demand on the transmission network. Thus, for the ten years of Information Disclosures by Transpower from 2015 to 2024:

- the non-opex revenue requirement was calculated, factored by the relevant CPI escalator to be in $2024.
- this was factored by the proportion allocated to distribution networks for 2024 (approximately 75%). This is intended to only consider Transpower's costs driven by EDBs, as opposed to Generators or Directly-Connected large industrial consumers.
- this was divided by the Maximum Peak demand (MW) from EDB offtake GXPs

The average of this value was $97/kW/yr – in contrast to the $240/kW/yr estimated for EDBs.

However, as with EDBs, not all of the costs of building the transmission network are driven by peak demand. Indeed, whereas a value of 55% was used for EDBs, it is considered that a significantly smaller percentage of Transpower costs are driven by peak demand. This is for two main reasons:

- firstly, a significant amount of the capital costs of the transmission network are driven by the need to build assets to connect and transport the power from all the various generators (hydro, wind, solar, geothermal, thermal) that are built around the country. Thus, there is a considerable annual *GWh* driver, rather than peak MW, to this aspect of demand-driven transmission cost drivers. This is different to distribution networks. For example, consider a scenario where annual GWh demand were to grow by 50%, say, but smart demand management meant that peak MW demand did not grow

  – there would still be a significant capital expenditure requirement for Transpower to build assets to connect and transport the power from all the new generators that would need to be built to meet this demand
  – in contrast, there would be little demand-driven requirements to invest to upgrade distribution networks.

  As a working assumption, we have assumed this GWh demand driver will halve the peak MW component of the transmission network demand driver compared to distribution networks.

- secondly, the capital costs of the system operator more than doubles the proportion of non-network capital expenditure for Transpower compared to the EDBs – ie, it is 19% compared to 8% for EDBs.

Taken together, this results in the proportion of transmission costs driven by peak demand falling from 55% to 22%. The resulting average peak demand-driven costs of transmission is $21/kW/yr, compared with $132/kW/yr for distribution networks.

A8. Ancillary services benefits

In addition to the energy market, the wholesale electricity market also procures ancillary services from generators and other resources to enable the system to be operated in a stable and secure fashion.

Currently[30], these services (excluding black start) are:

- Instantaneous Reserves (IR). Fast IR (FIR) and Sustained IR (SIR) are resources that are procured to sit on ‘stand-by’ so that they can be called upon at short notice (seconds) in the event of an unexpected loss of supply (eg, a generator tripping)
- Frequency Keeping. Supply sources that can second-by-second increase or decrease output to ensure that the frequency of the grid remains close to 50Hz
- Voltage support. Providing supply in specific grid locations to keep voltage within operating thresholds.

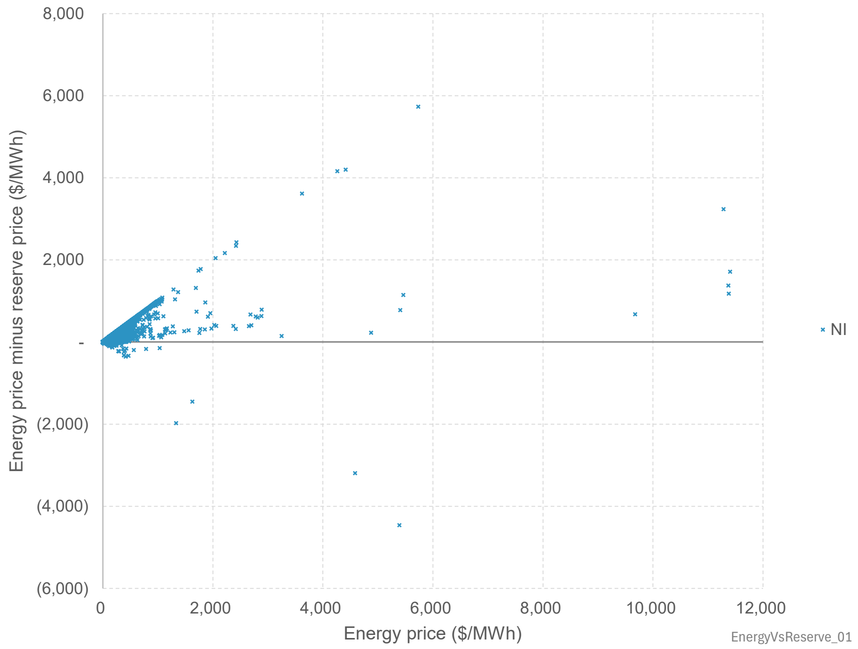
We see little opportunity for V2G to provide frequency keeping and voltage support services. The sizes of the markets are very small relative to energy (indeed, the System Operator currently procures no voltage support services and has not done so for many years), and the costs of overcoming the technical challenges of implementing V2G to provide such services seems unlikely to justify the potential benefit.

V2G could provide Instantaneous Reserves. However, it is not possible to provide energy from injecting power and Instantaneous Reserves at the same time. Accordingly, the greatest value is likely to be from providing V2G capability into the market which offers the highest prices.

Figure 28 shows a comparison of Energy prices (along the x-axis) with the difference between energy and reserve prices on the y-axis for every half hour for the ten years starting 1-Jan-2014. Points above the line correspond to periods where energy is more valuable than reserves, and points below the line are when reserves are more valuable than energy.

30 In the future, additional ancillary services may be introduced to manage emerging system needs (such as those resulting from an increasingly high renewables power system) but it is too early to speculate on what these might be, the extent to which V2G may be able to participate, and the value of such markets.

Figure 28: Comparison of Energy and Reserve prices

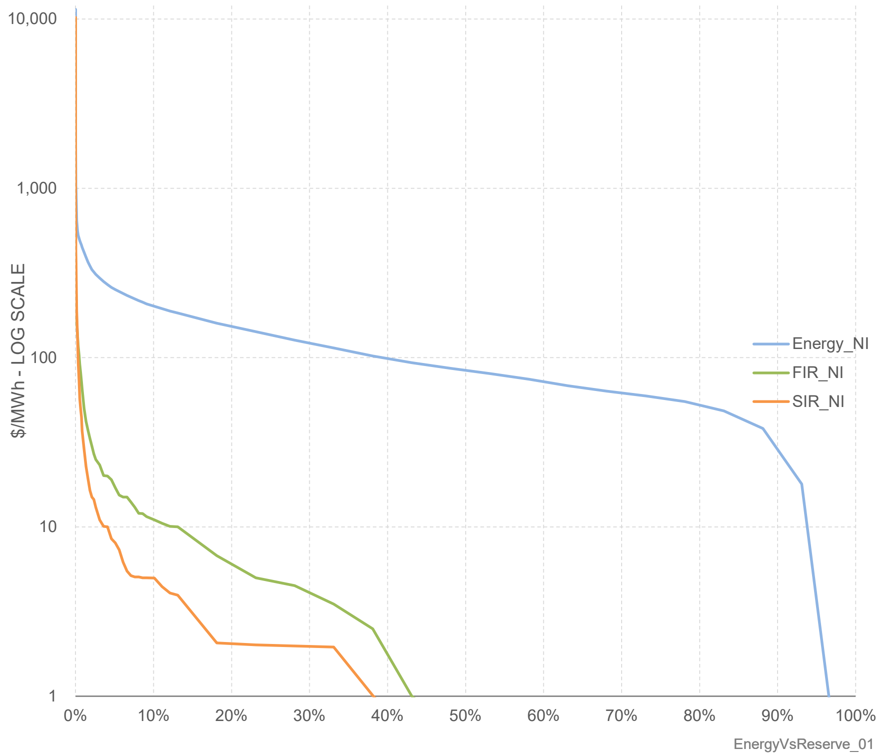


As can be seen, there were only four half-hour periods in the entire ten years where reserve prices were materially greater than energy prices.

A large part of the time, as indicated by the cluster of points along the 45-degree line, reserve prices are at or close to zero while energy prices are positive – sometimes reserves are at a very low price even when energy is at a very high price.

This is also illustrated in the following price duration curves for the same period.

Figure 29: Energy and Reserve price duration curves – LOG SCALE



For this reason, we see that by far the biggest value opportunity for V2G is in injecting power into the energy market at times of high energy prices.

That said, there should be some opportunity for vehicles to offer V2G capability into the IR markets at times when energy prices aren't high enough to justify injecting power into the grid. However, the level of prices achieved from this is likely to be relatively low.

For example, the average of FIR + SIR prices for 2014-2023 for periods when energy prices were below the 95th percentile level was approximately $7.8/MWh (all in real $2024).[31]

This potential revenue would need to be factored by the amount of time that the vehicle is plugged in to a charger that can facilitate V2G.

If it were plugged in for 50% of the time, this equates to approximately $34/kW/yr.

That said, the fact that batteries are emerging that can provide these reserve services at very low cost is likely to further depress reserve prices at these non-peak-energy-price times. This effect has already happened in Australia where the development of batteries has massively reduced the revenue that could be earned from providing FCAS ancillary services.

Because of this, we believe a reasonable estimate would be to halve this historic value.

A9. Cost of V2G

There are three potential areas where V2G may impose costs:

- more expensive Electric Vehicle Supply Equipment (EVSE) chargers
- more expensive vehicles
- battery degradation

EVSE charger costs

For a vehicle to export power to the grid, it must be connected to an external EVSE charger.

For light vehicles (cars, vans, and some light trucks) that would typically be charged via AC charging when at their base, the costs of the charger will depend on whether the vehicle has an on-board converter (OBC) that can inject grid-compatible power that meets the applicable power quality standards.

To date, almost all EVs in New Zealand don't have such grid-compatible OBCs[32], thereby requiring the external charger to have its own converter – ie, be DC charged.

EV manufacturers are now starting to produce EVs which have grid-compatible OBCs. While relatively few models currently have this capability, it is expected that within three to four years, an increasing number of new EV models will have grid-compatible OBCs.

Such EVs can therefore use a cheaper AC charger that doesn't have its own converter.

Vehicle costs

EV manufacturers are starting to produce vehicles with bidirectional charging capability:

- some vehicles using the CCS2 charging standard produced after 2022 are capable of bidirectional DC charging. However, it should be noted that globally only a few of the most recent CCS2 vehicles that have bidirectional OBCs that can potentially undertake V2G without the need for an external DC charger

31 FIR must be provided within six seconds of a contingency (and sustained for at least 60 seconds) to arrest a sudden fall in power system frequency. SIR must be provided within sixty seconds and sustained for up to 15 minutes to restore the power system frequency to normal levels. It is possible that some vehicles and/or V2G chargers may not be capable of the fast response required for FIR.

32 Potentially, only the Polestar 4 is the only vehicle model in New Zealand that currently has a grid-compatible OBC.

- all vehicles using the CHAdeMO charging standard are capable of bidirectional charging. However, all CHAdeMO vehicles require an external DC charger for V2G. Accordingly, this is not an area where V2G will result in significant cost savings. It should also be noted that there are very few V2G-capable CHAdeMO DC chargers in the global market, and that these CHAdeMO DC chargers can't be used to charge CCS2 vehicles. Using an existing V2G-capable DC charger with CHAdeMO vehicles is not a straightforward process
- Heavy vehicles using the MegaWatt Charging Standard (MCS) should be able to undertake V2G as a matter of course when using MCS charge points (provided the charge points fully meet the MCS specifications, meaning they should have bidirectional power converters and appropriate software).

Battery degradation

V2G has been shown to have a negligible impact on battery life in contemporary EVs. Indeed, as detailed in section E8 in Appendix E, some researchers have concluded that EV battery life can be *improved* through managed bidirectional V2G charging by keeping the EV battery at a more optimal state of charge while it is not in use and managing battery temperature.

Appendix B. Consumer choice

Appendix B looks at V2G technology from the consumer perspective, for households and for fleet owners of both light and heavy electric vehicles.

It also considers the perspective and importance of new vehicle importers/OEM representatives as a critical part of orchestrating V2G in New Zealand.

It suggests key messages for these different sectors and channels for communicating these key messages.

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B1. Household consumer perspective

2025 research by EECA, which surveyed private EV owners, reveals that around 50% of EV owners now have a fixed EV charger at home (not a 3-pin IC-CPD). EV owners with a fixed EV charger at home also tend to have newer EVs.

Cost savings and new technology are important motivators for many EV owners, EECA's research shows, and V2G ticks both these boxes.

The impact of V2G on the longevity of their EV's battery is likely to be a key concern for EV owners.

EV owners need to be able to capture a high proportion of the value of V2G to the electricity system, a potential of around $2,000 per EV per year, in order for them to consider making the switch.

The process is likely to need to be low-touch for EV owners to make the decision to implement and use V2G. A bundled service of EVSE installation and approvals, attractive tariffs, EV battery warranty for V2G and the ability to opt out for emergency/non-regular EV use being likely key components of a successful offering. While EV owners using V2G will need to establish the habit of regularly plugging in whenever they are at home, beyond this a "set and forget" approach to V2G will likely work best.

There will a few very early adopters who are prepared to go through all the steps needed to implement V2G themselves, but these should not be considered representative of the wider EV owning population. V2G technology is likely to appeal to EV owners who also have solar PV at home as they are already focused on investing in technology to reduce home energy costs, become more energy independent and/or be more sustainable.

Even with excellent V2G offerings to household consumers, V2G is unlikely to be a mass-uptake technology in the next decade, despite growth in EV uptake. This results not only from the anticipated EV owner behaviour perspective but also from the fact that the financial benefits of V2G to an individual EV owner will decline as the technology uptake grows. However, mass-uptake is not needed for significant benefits of V2G to be realised for the New Zealand economy.

B2. Communicating V2G to household consumers

According to EECA, online searches, YouTube videos and Facebook are where private EV owners are likely to look for information about V2G.

Key messages are:

- V2G can deliver an economic benefit of up to $2,000 per car each year
- EV owners can capture a sizeable portion of this economic benefit as cost savings
- the right EV and the right home charger is needed for V2G
- when buying an EV or EV charger, ask if it is capable of V2G and ask if the EV battery warranty covers V2G
- reputable companies with smart charging offers to EV owners with V2G chargers will start to become available.

B3. Light fleet operator perspective

The majority of new light passenger and commercial vehicles, including EVs, are purchased by fleets, including business, government and rental cars.

Many fleet vehicles are only used during business hours and are returned to car parks and depots before the evening, plugging in so that they are charged overnight if needed using connected smart charging.

Total Cost of Ownership (TCO) of fleet vehicles is an important part of a fleet manager’s vehicle selection criteria. Fleet operators have the potential to capture the value of these electric fleet vehicles when at their premises during the evening electricity peak, recharging overnight when electricity prices are low.

This is a potential of around $2,000 per year, contributing to lowering the TCO of electric fleet vehicles and influencing EV uptake in fleets.

For rental vehicle companies, having EVs in their fleet can provide benefits on the days when these vehicles are not rented out, including during the winter when rental vehicle demand from tourism is lower.

B4. Communicating V2G to fleet vehicle owners

While some organisations with light vehicle fleets have a dedicated Fleet Manager role, in smaller companies this role may be covered part-time by staff members in human resources or accounting.

Providing information about V2G directly to fleet leasing and management companies such as CustomFleet, FleetPartners, and SGFleet will be important, as well as to fleet managers directly through the fleet arms of vehicle importers/OEMs.

Using EV industry association Drive Electric events and fleet events such as EROAD Fleet Day will also be useful channels, along with trade publications such as New Zealand Company Vehicle.

For government fleets, working with New Zealand Government Procurement who manage the All of Government vehicle catalogue[33] to include information about V2G capability will be critical.

EECA provides information to business on fleet management and vehicle selection, including via their online Total Cost of Ownership tool which compares detailed specifications and costs of all new vehicle models available in the New Zealand market.[34] This could be adapted to include the option of V2G benefits.

Key messages for light vehicle fleet owners are:

- V2G can deliver an economic benefit of up to $2,000 per car each year
- EV owners can capture a sizeable portion of the economic benefit as cost savings
- EVs owned by fleets can capture a sizeable portion of the economic benefit a cost savings using V2G charging when parked and connected in the evening and overnight
- the right EVs and the right chargers are needed for V2G charging
- when procuring EVs or EV charging infrastructure, include criteria or questions about V2G capability and EV battery warranties covering V2G charging.

B5. Heavy vehicle operator perspective

Electrification of trucks has lagged behind that of light vehicles and buses both globally and in New Zealand.

As the capital costs of electric trucks continue to fall, a tipping point is approaching which will see the Total Cost of Ownership (TCO) of electric trucks become lower than that of diesel trucks in an increasing number of use cases, as the operating costs of electric trucks are significantly lower than for diesel trucks.

TCO of trucks is a principal consideration for the freight industry in selecting vehicles for their fleets.

EECA's Low Emission Heavy Vehicle Fund, which provides grants of up to 25% of the capital cost of zero-emission trucks, incentivises electric truck purchase by reducing TCO of electric trucks in comparison with diesel trucks.

If truck owners are able to capture a high proportion of the value of V2G to the electricity system, this is potential of around $10,000 per electric truck per year. This sum is significant in further reducing the TCO for electric trucks, increasing electric truck uptake.

Electric trucks that return to a depot in the late afternoon or early evening and do not need to go out again until the morning are excellent candidates for V2G. These include trucks undertaking waste collection, delivering fresh food to supermarkets and restaurants, delivering retail goods to shops, concrete trucks and trucks delivering other construction materials to work sites.

The use of V2G with electric milk tankers, which have a seasonal demand pattern where the tankers are off the road during the winter electricity peak demand months, provides even greater potential value to electric truck owners. It also ensures that batteries do not sit unused, which is not good for battery health, such as during the months when the milk tankers are off the road.

Electric public transport buses are less likely to be able to benefit from V2G than trucks as most are operating on the roads during the early evening electricity peak periods. However, there may be exceptions for applications such as school buses (although buses with shorter operating hours are less likely to be electrified).

[33] https://www.procurement.govt.nz/contracts/motor-vehicles/
[34] https://www.genless.govt.nz/for-business/vehicles-and-transport/vehicle-total-cost-of-ownership-calculator/

The use of electric coaches in the tourism sector has a seasonal variation which sees lower use in the winter months, echoing the use case for electric milk tankers.

Heavy vehicle operators considering V2G will be concerned with the impact of additional charge/discharge cycles on battery life and whether their vehicles will be fully charged by the start of every working day. The challenge of electrifying depots is unfamiliar to them, so they may see V2G as additional complexity that is too difficult.

B6. Communicating V2G to heavy vehicle owners

Heavy vehicle owners will want technical information directly from the New Zealand representatives of the truck Original Equipment Manufacturers (OEMs), including about battery warranties.

They will also look for information from the various organisations representing heavy vehicle owners in New Zealand such as:

- Ia Ara Aotearoa Transporting New Zealand
- National Road Carriers Association
- New Zealand Trucking Association
- Bus and Coach Association

Industry publications such as NZ Trucking and opportunities for face-to-face discussions such as trucking industry trade shows are other methods likely to be successful for communicating V2G.

V2G could be included in as an option in Total Cost of Ownership tools such as https://natroad.co.nz/cost-model/.

Heavy vehicle owners will likely want to see evidence from similar operators to their use case using V2G before investing in and deploying V2G technology themselves, so communicating with real-world, New Zealand case studies will be persuasive, particularly if about their competitors.

Key messages for the heavy vehicle owners are:

- V2G can deliver an economic benefit of up to $10,000 per heavy EV each year, or $25,000 for EVs that are off the road or driven less in winter months, such as milk tankers
- EV owners can capture a sizeable portion of the economic benefit
- the right electric trucks/buses and the right depot-based charging infrastructure is needed for V2G charging
- V2G charging can be set up so that electric trucks and buses are always fully charged for the following morning shift
- when tendering for an electric truck/bus or EV charging infrastructure, include questions about V2G charging capability and whether EV battery warranties cover V2G charging.

B7. Motor industry perspective

The potential significant savings from V2G for light and heavy electric vehicles owners is a new sales tool for EVs that are V2G-capable and have a battery warranty which allows for V2G operation.

Some OEMs are going down the AC V2G route where the EV has a bidirectional on-board charger and can use an AC charger, whereas other OEMs will select DC V2G where a more expensive DC charger with a bidirectional power converter is used. The vehicle charging communication standard ISO15118-20 is an important component of V2G compatibility for all vehicles with CCS2 charging.

New Zealand representatives of light and heavy OEMs may be competing against other countries to obtain V2G compatible electric vehicles, if there is local consumer demand for them. However, Australia and New Zealand are frequently viewed by OEMs as one market, so Australian actions and policies supporting V2G uptake that see V2G-compatible EV models available there may see the same EVs also being available in the New Zealand market.

Partnerships between OEMs/vehicle distributors and electricity sector entities or third parties to create offerings which make it easier for light and heavy EV customers to implement V2G can help vehicle distributors navigate this market opportunity.

The large number of electricity distribution companies in New Zealand may suggest to the motor industry that V2G will be difficult here, especially as different regional branches may have had to approach different electricity distribution companies to install EV charging at dealerships and workshops and experienced different processes, costs and lead times for this.

B8. Communicating V2G to the motor industry

The Motor Industry Association (MIA) is the industry body representing OEMs, both light and heavy. The MIA will be a key route in providing V2G information to representatives/importers of new vehicles. Drive Electric, which represents business operating in the EV space, including OEMS and EVSE manufacturers, are another key route to communicating V2G information. Articles in automotive trade publications and websites, such as Autotalk, Autocar and Autofile, are other channels for information.

Key messages for the motor industry are:

- V2G has the potential to generate significant savings for light and heavy EV owners in New Zealand, creating a new sales tool for EVs
- light EVs can deliver an economic benefit of around $2,000 per year and heavy vehicles that return to a depot in the early evening can deliver around $10,000 per year
- find out from your parent OEMs what their plans are for V2G in the Australasian market and any potential impact on traction battery warranties
- investigate partnerships with electricity market players and EV charging equipment manufacturers to provide a bundled offering for customers to make V2G easy for them with sales benefits for the company.

B9. Communicating the V2G value proposition

As described above, there are potentially thousands and tens of thousands of dollars in value (per annum, per vehicle) that light EV and heavy EV owners (respectively) could deliver to the electricity system through V2G.

Much of the value discussed in this report is available from offsetting demand at the premises (V2H or V2P) – ie, the biggest shift is from one-way to two-way charging, but to levels which don't exceed the premises' demand.

Another increment of value will sometimes be available if the property also injects back to the local network, but this can come with another layer of complexity and cost and is often unnecessary or secondary in terms of the value V2P can deliver. In any event, whether a property actually reinjects power to the network is not particularly salient to most consumers and the choices they make regarding their EV, their charger, and their smart charging service provider.

Without smart, remote management that optimises charging, V2G-enabled equipment is of limited value to the power system (and as penetration grows, is likely to become a cost-driver as EVs 'dump' power into peak tariff periods).

Savings or earnings?

Most consumers will not receive a payment into their bank account from providing V2G services. Instead, they'll enjoy a (potentially very material) reduction in the power bill, or their vehicle lease costs.

This is because most of the value transfer to consumers for V2G services comes for reductions in network charges and energy purchase costs. For example:

- lower network charges due to lower net demand at peak
- eligibility for lower cost ‘type of use’ network charges
- lower average energy costs from avoiding periods when wholesale electricity prices are high.

Revenue from V2G is possible too, from:

- ‘negative pricing’ credits that offset daily lines charges
- energy arbitrage profits that partially offset month energy purchase costs.

However, for context:

- the average household power bill in Auckland is currently $2,700 per year
- our estimated value for a light vehicle is around $2,000
- some portion of the value must go toward equipment and service costs.

As such, it may be generally preferable to talk about ‘savings’ from two-way smart charging, rather than earnings – unless a particular service for a particular vehicle type actually generates payments for the consumer. The precise language will require some thought to ensure the message is understood by consumers without being misleading.

How much?

The figures used in this report provide a guide to the value available on average from representative vehicle types. However, care should be taken not to over-promise.

In particular:

- value transfer depends on cost-reflective tariffs, which are not yet widely available
- the underlying value available varies through time and by location. Some areas at some times will have higher avoidable costs, and some will have lower
- the ‘raw’ values we have identified will be higher than realisable values
- the realisable value must also fund equipment and services, including a return on investment for service providers.

As such, the figures in this report – such as $2,000 per light vehicle – are appropriate for communicating the ‘value’ or economic benefit of V2G, but not potential savings for consumers.

For consumer savings, it is more appropriate to claim that consumers could capture a ‘sizeable portion’ of the economic benefit.

Electricity sector mindset

Traditionally the electricity sector has relied on tariffs (and adjacent price-based mechanisms as described in Section C7) to incentivise consumer behaviours. Whilst some consumers find these mechanisms engaging – e.g., technically minded “prosumers” or customer segments like students (that are cost-conscious but time “rich”) – others will crave low-touch (but still compelling) offerings.

As Ron Ben-David (Professorial Fellow, Monash Business School) argues, the electricity system has viewed consumers in electricity market and regulatory design in three distinct phases:[35]

- Initially, the industry largely "conceived of consumers as disinterested and passive takers of electricity," as seen in flat variable rate billing structures that tended to dominate vertically integrated utilities of yesteryear, with negligible choice for most consumers to switch to different tariffs.
- Then, as electricity sectors worldwide were undergoing deregulation, and retail competition was being encouraged, consumers were increasingly seen as "active and discerning shoppers of electricity." Consumers were expected to find the best deals for themselves and consider different tariff structures offered to them by competing retailers, some of whom would often offer more complex multi-part/time-of-use pricing.
- Much more recently, coinciding with the prospect of burgeoning consumer energy resources (CER) and the potential to promote sector-wide efficiencies in deferred investments across centralised generation, transmission and distribution, consumers are increasingly seen "as 'market participants' [or traders even] who are interested, willing and capable of trading the shape of their load, the volume and timing of their electricity exports, and access to their storage assets (including EVs)."

Ben-David argues that this evolution is not necessarily the natural order of things, and that the electricity industry today is a product of its past and "regulatory narrative[s] about the relationship between energy consumers, markets and regulation."

So, in today's world view of consumers as active "market participants," there is a very real risk that:

> "the only consumers who can make it to "the centre" [of the industry's gaze] are the ones who proficiently participate in the ways presumed in the market's design. For other consumers, the regulatory ideal rings hollow [or could prove financial damaging or a disengaging experience]."

Thus, Ben-David exhorts the industry to adopt a new regulatory objective focussed on "upholding consumer confidence during the energy transition." In other words, "avoid exposing consumers to risks they are ill-equipped to understand, manage or price."

35 It's time to rethink how we think about the consumer energy market

Appendix C. Technology platforms

Appendix C provides more detail to support Chapter 4, which discusses the technical platform for V2G. The appendix covers:

C1. Next-generation consumer energy resources

From an electricity sector perspective, V2G is a source of flexibility – ie, a resource that can help with managing capacity constraints, and with real-time matching of supply to demand.

In that sense, it sits alongside technologies such as hydro and thermal generation and large flexible industrial processes. In contrast with those technologies, (most) V2G involves coordinated response of many small resources connected at the low-voltage fringes of the power system.

This type of flexibility is sometimes referred to a 'distributed energy resources' or DER. Another distinguishing feature is that V2G involve control of resources owned by end consumers. As such, the term 'consumer energy resources' or CER may also be used.

Ripple-based hot water cylinder control (R-HWC) is a well-established CER in New Zealand that has (and continues to) deliver significant value in managing demand peaks.

Next generation (NG-CER) technologies that could deliver material value in future include:

- next-generation hot-water cylinder control (NG-HWC) – ie, digital communications and control systems for hot water systems that enable each cylinder to be monitored and controlled individually
- smart charging (V1G) – EV charging that can be remotely throttled or paused
- V2G – EV smart charging that can also draw power from the EV to offset demand or inject back into the local network
- stationary batteries – batteries at a home or business that can operate in the same manner as V2G. Typically, lower capacity and higher cost than V2G, but always available. Commonly installed in conjunction with solar (to convert low-value daytime production into higher-value evening production).

Remote communications and control can also be used with CERs such as heat pumps and household appliances, but these are much less valuable in terms of their ability to help manage demand peaks.

Our analysis indicates that HWC and V1G alone are enough to enable households to meet all their energy needs with electricity without contributing to the need for any increase in peak capacity. V2G adds more value – helping offset peak demand growth from households without CER and from non-household growth.

To enable these technologies to reach their potential, the electricity sector needs to work through and resolve a number of matters:

1. ensuring suitability of devices for safe connection and operation
2. recording device locations and capabilities
3. ensuring suitability of communications and control systems
4. establishing parameters for safe and effective control
5. incentivising productive use.

For R-HWC, these matters have largely been a concern of each separate distribution network. For NG-CER, there is a stronger need to ensure arrangements:

- support the existence of a common Trans-Tasman market for EVs and EV chargers
- enable NG-CERs to be deployed for network, generation and direct consumer (eg, household backup) purposes
- enable interoperability of diverse communications and control systems
- support the existence of a single nationwide market for control services.

In addition, the potential scale of V2G means it will become important for the System Operator to have operational awareness (as a minimum) and emergency recourse (eventually).

Because V2G (and stationary batteries) can also involve net injections into local networks, it will also become important to have arrangements in place for protecting networks from injection overload.

Overall, there is a stronger benefit for NG-CER to national consistency of approach than has been the case for RC-HWC.

C2. EV charging

All electricity grids around the world operate on an Alternating Current (AC) basis. However, the battery within electric vehicles operate on a Direct Current (DC) basis. Therefore, to charge an EV from the grid it is necessary to convert the AC grid electricity to DC to charge the battery. How this happens varies between types of Electric Vehicle Supply Equipment (EVSE) or “charger”:

- When an EV “fast charges” using a “DC charger” (Mode 4 charging), the EVSE provides DC power directly to the EV battery. For DC charging, the EVSE contains a power converter (rectifier) to change the AC from the external electricity system to DC for the car battery.
- When an EV “slow charges” using an“AC charger” (Mode 3 charging), the EVSE provides AC power to the EV and an on-board power converter in the EV converts the AC to DC for the battery. Not having a power converter is one of the reasons that AC chargers are much cheaper than DC chargers.

The term Vehicle-in-Grid (V1G) is used to describe one-way smart charging where communication between the grid and the EVSE is used to control the timing or power of EV charging to manage costs, loads and/or overall emissions. Standards NZ Publicly Available Specifications for EV charging require that smart charging supports OCPP 1.6 or above.

Bi-directional charging is when electricity can also flow back from the EV battery to an external electricity system. Types of bidirectional charging include:

- vehicle-to-load (V2L): This is when the EV’s on-board power converter is bidirectional and can also convert DC back to AC to power an external load such as an appliance, *that is not connected to the grid or a building’s circuits*. This provides electricity for activities such as operating power tools at remote work sites and running appliances when camping. There are a number of new EV models in New Zealand that provide V2L capability today including from BYD, Ford, Geely, Hyundai, Kia, MG, Polestar and Smart, at up to 3.6 kW. Some of these EV models proved themselves during Cyclone Gabrielle providing electricity for essential equipment[36]

- vehicle-to-home (V2H) or vehicle-to-building (V2B) or (more generically) vehicle-to-premises (V2P): This is when an EV can be integrated into a house or building's switchboard, similarly to a stationary household battery used with a solar photovoltaic (PV) system but injects to a level that never exceeds the property's demand. This allows the EV battery to charge off-peak when electricity prices are low and supply it back to the house when electricity prices are high, or store excess power generated by solar PV panels during the day and provide this back in the evening. For V2H there is just one electricity customer, the householder. For V2B there may be multiple electricity customers and there may be a fleet of EVs. A V2P system can also provide the home or building with some electricity during a power-cut. With a V2P system there is no flow of electricity back to the electricity network
- vehicle-to-grid (V2G): V2G is fundamentally the same as V2P except that the EV injects power to a level that exceeds the property's demand, such that the EV battery and building system supplies electricity back to the electricity network, similar to exporting electricity from a solar PV system or other distributed generation. As for V2P, there is potential for energy arbitrage, but V2G can also provide ancillary services to the local electricity network. For AC V2G charging, the vehicle's on-board power converter needs to be V2G compatible and comply with local standards.

Together these different types of bidirectional charging are often colloquially called "vehicle-to-everything" (V2X).

As V2L is commonly available in New Zealand already and faces no significant barriers to uptake, it is not covered further in this report.

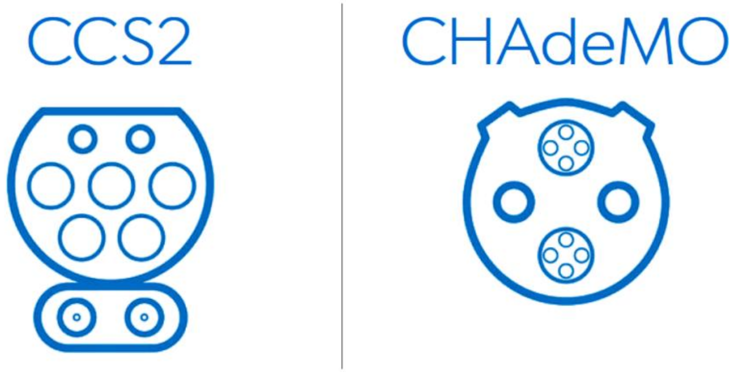
V2P and V2G has the potential for the greatest value to New Zealand.

C3. Charging connector standards

There are two DC electric vehicle charging connector standards recommended in Waka Kotahi NZTA Guidelines[37] - Combined Charging System Combo 2 (CCS2) and CHAdeMO.

CCS2 is the connector type now used for all NZ new light and heavy EVs, and the upper part of the CCS2 port also accepts a "Type 2" AC charging connector, as shown in Figure 30.

Figure 30: CCS2 combined AC and DC charging connector and CHAdeMO DC charging connector



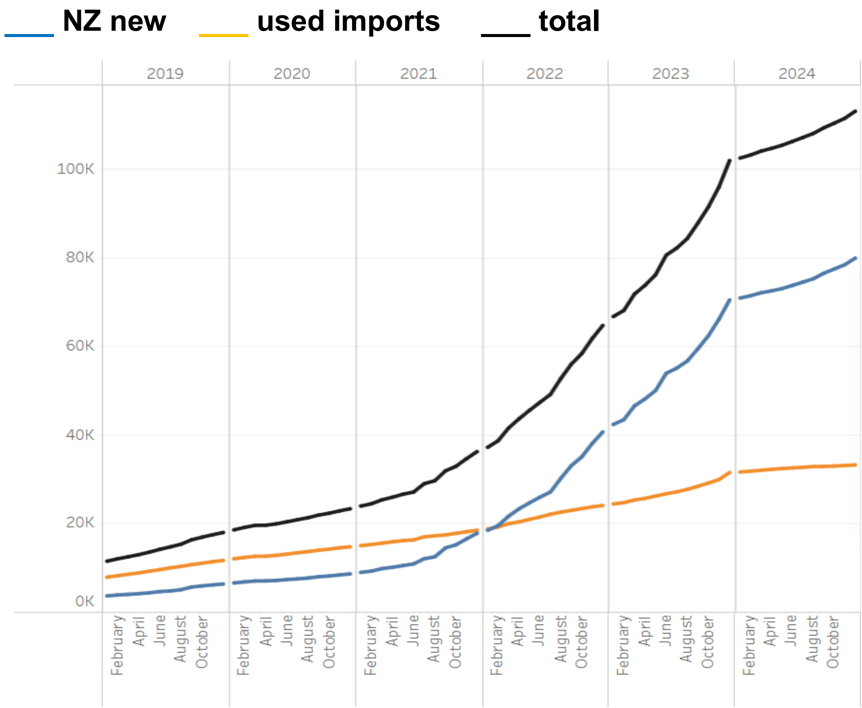
36 https://www.autocar.co.nz/evs-being-used-to-power-homes-following-cyclone/
37 https://www.nzta.govt.nz/planning-and-investment/planning/transport-planning/planning-for-electric-vehicles/national-guidance-for-public-electric-vehicle-charging-infrastructure/charging-point-connectors-and-socket-outlets/

CHAdeMO is the DC connector type widely used in Japan and is present in most used-import EVs from Japan. Japanese used-import EVs also have a separate port for a “Type 1” AC charging connector.

New Zealand is relatively unique amongst OECD countries in permitting Japanese used-vehicle imports without any import taxes or customs duty. Around half of all passenger cars entering the New Zealand fleet are used imports from Japan. However, the proportion of registrations of used EVs from Japan has been falling as a proportion of total new EV entrants to the national fleet from around 70% in early 2019 to less than 20% in early 2025[38], as shown in the Ministry of Transport graph in Figure 2. “EVs” includes plug-in hybrid electric vehicles (PHEV) as well as 100% electric Battery Electric Vehicles (BEV).

The number of CCS2 EVs overtook CHAdeMO EVs at the start of 2022 and CCS2 is now the dominant charger system in New Zealand. Newer vehicles with CCS2 charging also tend to have larger batteries than older Japanese imports.

Figure 31: EV fleet size by import status



Source: Ministry of Transport

Mazda and Honda have announced that in the future they will be using the North American Charging System (NACS)/SAE J3400 connector in Japan, a standardised version of Tesla’s proprietary connector that is already in use in Japan with Tesla vehicles and chargers (NZ new Tesla vehicles now use CCS2).

In North America, NACS uses the ISO15118 communication protocol between the vehicle and the charger. However, the NACS connector form is agnostic to communication protocol, and (at the

38 https://www.transport.govt.nz/statistics-and-insights/fleet-statistics/monthly-mv-fleet/

time of writing) it is yet to be seen what protocol will be used with NACS for Japanese domestic vehicles, that may be imported as used vehicles into New Zealand in the future.

If Japanese vehicles with NACS use a protocol other than ISO15118 then there will be interoperability issues in New Zealand even if using an OEM-provided adaptor between NACS and CCS2.

The CCS2 connector is used in New Zealand for heavy vehicles – buses and trucks – as well as mobile machinery such as wheel loaders and the Wellington electric ferry. Most heavy EVs can only DC charge, although some smaller urban truck models can also AC charge and some after-market truck conversions to battery electric can only AC charge.

There are some early electric public transport buses operating from an Auckland depot that were imported with the Chinese GB/T connector and still use this for depot charging. However, the NZTA Requirements for Urban Buses[39] now specifies that all public transport buses use the CCS2 connector, and the NZTA charging connector guidelines also apply to heavy vehicles.

C4. EV communication protocols and standards

EVs with CCS2 charging use the ISO 15118 communication protocol between the EV and the EVSE (external charger), while EVs with CHAdeMO charging use the communication protocol defined in IEC 61851-23 ANNEX BB and JIS/TSD0007.

The ISO 15118-2 communication protocol was supplemented in 2022 with ISO15118-20, with more charging features, including bidirectional charging feature. Table 1 shows charging features related to these two connector standards.

As at mid-2025, ISO 15118-20 is functional for DC V2G and there is an upcoming revision to complete the protocol for AC V2G. This may take a couple of years to flow through to AC V2G-capable EVs.

Some existing EVs with the ISO 15118-2 communication protocol can use DC V2G with some external chargers. For full interoperability for V2G, EVs and EVSE both need ISO 15118-20.

Table 1: Selected features of charging system standards

Charging system	CHAdeMO	CCS2	
Comms protocol	**IEC 61851-23/24**	**ISO 15118-2 (2014)**	**ISO 15118-20 (2022)**
DC	Y	Y	Y
AC	N	Y	Y
Transport layer security	N	Y	Y
Plug and charge	N	Y	Y
Smart charging	N	Y	Y
Bidirectional charging	Y	N	Y
Automatic connection	N	N	Y

Transport Layer Security (TLS) ensures that communications between the vehicle and charger are secure. CHAdeMO does not have TLS and so is at greater risk of hacking.

Vehicles later than 2022 with CCS2 charging and upgraded to use the ISO 15118-20 protocol have the potential to use a two-way DC charger to send power back to the grid. Emerging vehicles using CCS2 and ISO15118-20 can use a two-way AC charger if the EV also has a V2G compatible on-board power converter (inverter) that

[39] Requirements for urban buses in New Zealand (the 'RUB') | NZ Transport Agency Waka Kotahi

complies with local network standards. The V2G compatible power converter must discharge an AC wave form that is synchronised with that of the electricity network.

CHAdeMO supports bidirectional charging but can only supply DC power. Consequently, for CHAdeMO vehicles the EVSE must be a DC charger that contains a suitable power converter and appropriate software for V2G. There are very few of these types of CHAdeMO V2G DC charger in the global market. DC V2G chargers for light vehicles for domestic use cost at least five times more than AC V2G chargers, due to the power conversion devices they require,[40] although this premium is likely to reduce over time as market volumes, technology and competition continues to develop.

A CCS2 compatible DC V2G charger cannot be used with CHAdeMO vehicles (and vice versa) as the two charging systems are not interoperable.

The Open Charge Point Protocol (OCPP), which is maintained and published by the Open Charge Alliance, is a communication protocol between charging infrastructure and Charge Point Operators or other platforms that manage EVSE and is the de-facto standard,[41] including in Australia and New Zealand.

OCPP 1.6 was released in 2015 and is in widespread use. OCPP 2.0.1 was released in 2020. OCPP 2.0.1 ed3 was published as an IEC standard (IEC63584) in 2024 and includes smart grid support. OCPP 2.1 was released in January 2025, is also an IEC standard and supports V2G natively with ISO15118-20 and enhanced integration with distributed energy resources (DER)[42].

MegaWatt Charging System (MCS)

A new charging connector for heavy vehicles is being introduced globally during 2025 – MegaWatt Charging System (MCS). This is capable of charging rates up to 3.75 MW. The MCS specifications were developed by the same organisation, CharIN, that developed CCS2, and MCS also uses the ISO15118 communications protocol.

Many large trucks are likely to feature both CCS2 ports for DC depot charging and MCS ports for DC journey charging. MCS uses the ISO15118-20 communications protocol.

MCS supports V2G capability, so EVs that have MCS charging and MCS EVSE can be natively V2G capable and use the ISO15118-20 communications protocol, if certified to the standard.

The first deployment of “MCS” connectors in New Zealand is likely to be for the Auckland electric ferries, with up to 3 MW charging being installed in mid-2025 by Auckland Transport for sea trials for the first four electric ferries to be used in Auckland’s public transport ferry network. The charging infrastructure is being installed in the Downtown Ferry Terminal in central Auckland, Half-Moon Bay and Hobsonville. As this charging infrastructure was designed and procured before the MCS standards were finalised, the charging infrastructure for the ferries is not V2G capable but can be retrofitted.

Two-way power equipment

To allow V2G, the following hardware and software components are required in EVs and EVSE, all of which operate using ISO15118-20.

40 (PDF) A Grid-Friendly Electric Vehicle Infrastructure: The Korean Approach
41 https://www.ffe.de/en/publications/normenlandschaft_fuer_die_elektromobilitaet/
42 https://openchargealliance.org/ocpp-2-1-is-now-available/

Table 5.5: Components required in EVs and EVSE for V2G

	EV	EVSE
AC V2G	Bi-directional on-board charger Grid code functionality	Bi-directional metering Grid code feature
DC V2G	Bi-directional control in the battery management system (BMS)	Bi-directional power converter Grid code feature

EVs that can charge with an AC EVSE have on-board chargers (OBCs). These have generally been one-way OBCs to date. Two-way OBC are now being used in some EV models globally, allowing a V2G configuration using a low-cost external AC EVSE.

Bidirectional OBCs have a converter that can convert DC from the battery to grid-compatible AC. This involves synchronising the AC wave form with the electricity network and correcting 'power factor' to avoid impairing power quality.

For light EVs, while DC V2G chargers are significantly more expensive than AC V2G chargers, many existing EVs can use this technology so it is quicker to implement.

While AC V2G chargers have the potential to be significantly lower cost, the challenge is that different countries and electricity networks have different grid standards – including frequency and voltage settings. Accordingly, vehicles must be configured for different markets and need the ability to have updates (either 'over-the-air' or via servicing at a garage) to maintain compatibility.

Countries like New Zealand, with a small EV market size potentially have a more challenging path to AC V2G charging.

C5. Device standards

Device-level standards are necessary for DER (including EV chargers) so they can safely interact with the power system and contribute to its efficient operation.

Relevant standards for V2G chargers include:

- **Inverter standards** such as AS/NZS 4777.1 and 4777.2 specifying safety and installation requirements for inverter energy systems, expected performance and behaviour of inverters at low voltages
- **Grid interconnection standards** such as IEEE 1547 outlining criteria and requirements for interconnection of DER with power systems and covers AS/NZS 4777 functionality also
- **Mandatory "smart" functionality** to ensure devices are capable of being flexed "out of the box" and/or are configurable to operate on a timer. This concept is currently being consulted upon by MBIE,[43] alongside voluntary or mandatory labelling to help consumers identify smart chargers. Smart chargers also offer an added benefit of usually being capable of "over-the-air" software updates to allow for evolving standards related to V2G capability. Cybersecurity is also a consideration for smart chargers and ISO15118-2 and -20 provides this with the Transport Layer Security feature
- **Electrical safety** as outlined by WorkSafe's guidelines[44], which in turn refer to several AS/NZ standards, IEC standards and other requirements to ensure safety in design, specification, supply, installation and operation of EV charging equipment.

43 Proposals to support the uptake of smart electric vehicle charging
44 Guidelines for safe electric vehicle charging | WorkSafe

One challenge for the uptake of emerging technology like V2G in New Zealand is the fact that some official standards referred to in regulations are part of legislation that cannot be readily updated to keep pace with new standards and new versions of existing standards. For example, the Electricity (Safety) Regulations 2010 reference AS/NZ 4777.1:2005, which does not contemplate V2G charging, although the 2024 version does.

Fortunately, regulatory change is underway to streamline New Zealand's process:

- through the Regulatory Systems (Immigration and Workforce) Act, changes have been made to the Electricity Act 1992 so that instead of the current regulations process, WorkSafe will be able to create "safety instruments" which can set out what standards need to be used
- new/updated safety instruments would be approved through agreement from the Minister for Energy, a power which could also be delegated to WorkSafe
- with the primary legislation having been passed – i.e., The Regulatory Systems (Immigration and Workforce) Act – the Electricity Safety Regulations 2010 will now need to be amended to enable the new safety instruments process

C6. Device registration and network connection

Device registration

Visibility over flexible resources available to the power system is invaluable for:

- informing transmission and distribution network investment planning and operations – so that the transmission grid owner and distribution network owners can identify opportunities to defer traditional "poles and wires" investments through flexibility
- informing power system operations and associated planning at both the distribution and transmission level – so that the transmission system operator and future distribution system operators can forecast and plan for demand patterns more readily, as well as identifying opportunities to procure services from flexibility to promote more secure and efficient system operations
- building interest and confidence amongst potential flexibility procurers (e.g. networks, retailers, and aggregators) – so that they know what flexibility potential exists (and where) to be procured
- building interest and confidence amongst potential flexibility controllers (e.g. aggregators), and resource holders (e.g. households, businesses, small generators) – so that these parties may know what flexibility potential exists (and where) that they can harness and/or contribute to.

Information about distributed generation and batteries able to inject power into the grid is already available due to Part 6 of the Code governing distributed generation connection and the related processes undertaken by distributors.

The obligations set out in Part 6 result in distributors' connection agreements requiring customers wanting to inject into the network to notify the distributor. The distributor then records this information against the relevant Installation Control Point (ICP) in the electricity registry.[45]

However, information at ICP level is *not* readily available regarding:

- demand response resources – i.e. appliances or devices that can be signalled remotely and/or controlled locally to reduce demand
- non-injecting generation and storage – i.e. resources that are embedded behind load and the ICP's meter and never result in net injection from the ICP onto the grid
- flexibility rights – i.e. technical and commercial arrangements that allow a party to control a group of flexibility resources.

This lack of information about potentially significant sources of flexibility will hinder good decision making for planning and operation of the system.

In response to this lack of information, some distributors are starting to mandate information submission on non-generation flexible resources. For example, Vector's network connection standard requires a certificate of compliance and ICP information to be submitted to Vector in relation to EV chargers.[46] However, such EDB initiatives are resulting in EDB-specific systems and processes for storing and publishing such data, with likely variations in what is collected and published.

We therefore see value in Code changes to require:

- implementing a centralised flexibility register that would be maintained and overseen by a market operation service provider like the registry manager,[47] or even the registry manager itself
- establishing 'flexibility controllers' (e.g., aggregators, generators, retailers, and/or distributors with control rights over various resources) as a class of participant
- requiring flexibility controllers to record information about 'flexibility units' in the register. These are groups of controllable resources with similar technical characteristics and control rights. Information would relate to the aggregate capability of the flexibility unit – eg, it's likely (P50) and low (P5) capability in terms of power (kW), duration and restoration
- linking flexibility unit information to individual ICPs in the registry (ie, so the registry record for each ICP will identify if the ICP is part of a flexibility unit)
- providing tailored flexibility information retrieval rights for some participants (e.g., distributors, Transpower, regulators and so on)
- providing open access to reporting on aggregate information.

Collection, storage and dissemination of information about "flexibility units" could have implications under the Privacy Act 2020 should some information fall under the definition of "personal information." The flexibility register would then need to be designed around the Act's 13 privacy principles – e.g., storage and security, corrections, use of information in line with the purpose(s) for which it was collected, appropriate disclosure and so on.

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45 The electricity registry is New Zealand's central record for ICP information. It records connection, metering and network pricing information, as well as listing the wholesale market participant ("trader") responsible for the ICP. It is primarily used for retailers switching customers in and out. More information about the electricity registry can be found at Electricity registry (ea.govt.nz) and in the Functional Specification document, which can be downloaded at Registry Logon (electricityregistry.co.nz).

46 Refer: Electric Vehicle Charger Compliance | Vector Limited.

47 Market operation service providers | Electricity Authority

The flexibility register would best exist as a separate system from the existing electricity registry because:

- it is organised around flexibility units, not ICPs. Flexibility units have aggregate properties (such as after-diversity capacity)[48] that are not meaningful at ICP level
- the flexibility register will have a different set of users to the electricity registry, albeit with significant overlap
- the flexibility register will have a comparatively low volume of information exchange, and high rate of change and development as flexibility arrangements mature. This contrasts with the electricity registry, whose architecture is comparatively stable and handles large data volumes.

While a flexibility register would likely help with harnessing V2G (and flexibility in general), some challenges will remain:

- flexibility controllers may not always update the flexibility register with complete or accurate information, as is apparently the case (anecdotally) with rooftop solar information in the registry and other forms of distributed generation
- developing standardised ways of characterising the aggregate capability of flexibility units will take time. They depend on the underlying technology (eg, EV battery and charger), end user behaviour (eg, when EVs are plugged in) and the contractual arrangements for control (eg, service levels).

Broader industry developments

The benefits from a flexibility register may also be limited unless other, broader industry developments occur in tandem. For example:

- mandatory "smart" functionality to ensure EV chargers (and other flexible devices) are capable of being flexed "out of the box" and/or are configurable to operate on a timer. This concept is currently being consulted upon by MBIE for EV chargers,[49] alongside voluntary or mandatory labelling to help consumers identify smart charging devices
- enabling Multiple Trading Relationships (MTR) so a consumer at a single ICP may engage multiple retailers (currently this is limited in the Code to one-to-one relationships) or electricity service providers (No specific limit exists on the latter, but third-party service providers may face obstacles in promptly obtaining data such as the consumer's consumption patterns.) MTR has the potential to spur innovation and competition by, for example, allowing aggregators to work with consumers independently of their retailer to derive benefits from flexibility (eg, an aggregator could contract independently with consumers to deliver contracted flexibility to a distributor and share the benefits with those consumers.) The Electricity Authority has recently consulted on this topic[50]
- standardised flexibility products and flexibility marketplaces are a logical extension of a flexibility register. In other words, once flexible assets are registered according to common definitions, they can then be readily "put to work" for the benefit of consumers and the wider power system if standardised flexibility

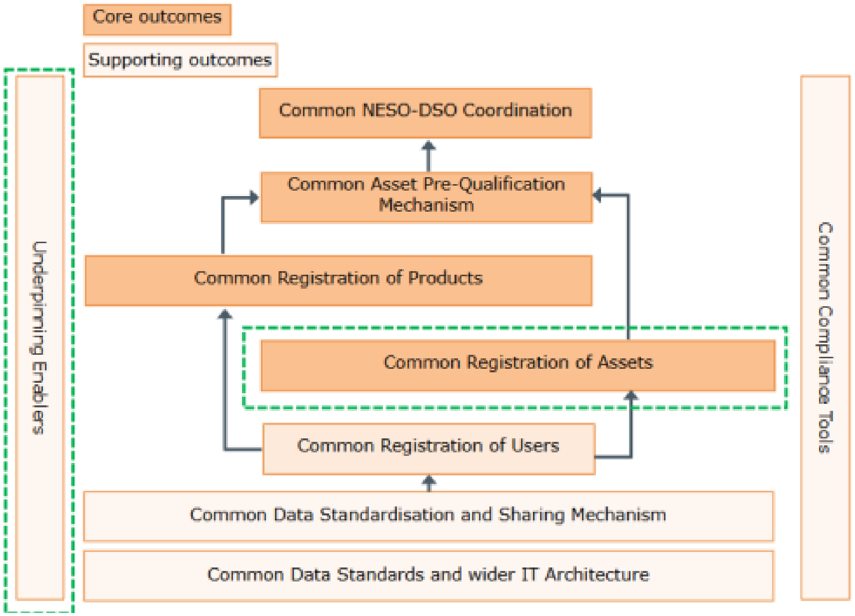
48 After-diversity capacity describes the phenomenon where the maximum capacity of an aggregated unit is less than the sum of the maximum capacities of each individual resource. This is due to the different behaviour of individual resources – i.e. they are not all used/able to be used at the same time.

49 Proposals to support the uptake of smart electric vehicle charging

50 Multiple trading relationships | Our consultations | Our projects | Electricity Authority

products can be traded within flexibility marketplaces. These concepts form part of Ofgem's vision for "Flexibility Digital Infrastructure" in the United Kingdom – common asset registration, common product registration and thus common asset pre-qualification for certain use cases and markets

Figure 32: Ofgem's Flexibility Digital Infrastructure



- miscellaneous Code and regulatory changes to facilitate consumers and other industry participants benefitting from flexibility. For example, sale of V2G export power to parties other than the consumer's own retailer may be impeded if consumers are captured by the Code's definition of a traditional retailer and/or other onerous (e.g., tax) regulation.

C7. Network connection

Generation connection processes and V2G

The key factor that sets V2G apart from many other forms of flexibility is that it is capable of injecting power into the network rather than just modifying consumption.

This means that V2G, if it results in net injection onto the transmission grid or distribution network, is likely to meet the definition of "generating plant" in the Code ("equipment collectively used for generating electricity") and thus subject to processes governing the connection of generation under Part 6 of the Code governing distributed generation (if connecting at distribution level) or Transpower-specified processes (as grid owner and system operator if a V2G-capable site is connecting at the transmission level).[51]

Connection and operation standards

Distributors set connection and operation standards per Part 6 of the Code governing distributed generation, which would encompass V2G but not all flexible DER.

Notwithstanding the above, distributors have always set certain requirements for loads. For example, on the Orion network, residential customers must have hot water cylinders configured for ripple control and can opt-out of routine ripple control but not emergency control. Participation in ripple control entitles the resident to a discounted, "controlled" tariff.

[51] Transpower processes may be relevant for high-capacity V2G-capable EV charging sites with tens of megawatts of capacity (eg, a large public charging site with dozens of Megawatt Charging Standard sockets for trucks) or a large transmission-connected *load* site that hosts V2G-capable EV chargers, such as a dairy processing plant with V2G chargers for milk trucks.

Standards impose costs on connecting parties and can lead to ongoing costs for the distributor – for example, to verify compliance and ongoing availability. However, standards can ensure properties have readiness built in and can reduce the transaction cost for accessing flexibility – including by reducing the difficulty and the lag involved in recruiting customers.

Vector's network connection standard requires EV chargers connected to the network to comply with SNZ PAS 6011:2021 and SNZ PAS 6010:2021 (standards for residential and commercial EV charging respectively that contemplate signals from electricity suppliers for managed charging) with the aim of ensuring "that customers [and indeed the network] will be able to benefit from load management, should it become available to them in future."

Standards can also be platform-specific as opposed to appliance-specific. Appliance-specific standards refer to specific requirements on devices like hot water cylinders, EV chargers and so on as described above. Platform-specific standards may capture flexible devices by requiring them be enrolled for monitoring and management via a particular platform or technology – ripple relays or Distributed Energy Resource Management Systems (DERMS) for instance.

A distributor could even allow consumers to select from a range of approved third-party control platforms or only require provisioning of controllability (without requiring connection to a platform).

Where standards do require participation in a platform, this can be on an "opt out" basis or partial opt out (eg, opt out of routine control but not emergency control) as seen in the example of Orion's hot water cylinder control.

"Standardising the standards" in relation to connecting flexibility across distribution networks would likely be beneficial for consumers and flexibility controllers (eg, aggregators and retailers) alike.

Dynamic Operating Envelopes

Network connection and operation standards may also set capacity limits, which may differ from physical capacity.

As an alternative to setting very low limits (or denying access) for new solar in countries with high uptake (eg, Australia), some networks are trialling a more flexible approach with tailored capacity limits – either static (agreed in advance) or dynamic (adjusted depending on network conditions). The latter is sometimes referred to as a Dynamic Operating Envelope (DOE).

Some distributors are exploring DOE approaches for load technologies. For example, a distributor could alter their connection standards to deny connection of EV wall chargers unless the charger is able to be managed via a DOE.

DOEs can be communicated to smart devices enrolled with a DERMS, using standards like IEEE 2030.5[52] and the Common Smart Inverter Profile – Australia (CSIP-AUS).[53] For instance, Vector's (optional) DERMS connection standard[54] contemplates the DERMS connection providing "a forecasted dynamic operating limit based on network conditions." The customer enrolled in Vector's DERMs is then potentially entitled to take advantage of improved commercial arrangements, be they capital contributions, connection fees, tariffs and/or direct payments.

52 However, for EV charging, OCPP is also commonly used.
53 https://arena.gov.au/knowledge-bank/common-smart-inverter-profile-australia/
54 https://www.vector.co.nz/kentico_content/assets/017af66a-0f21-433a-804d-0093aae44848/ESS900_DERMS_Connection_Standard.pdf

C8. Communications and control

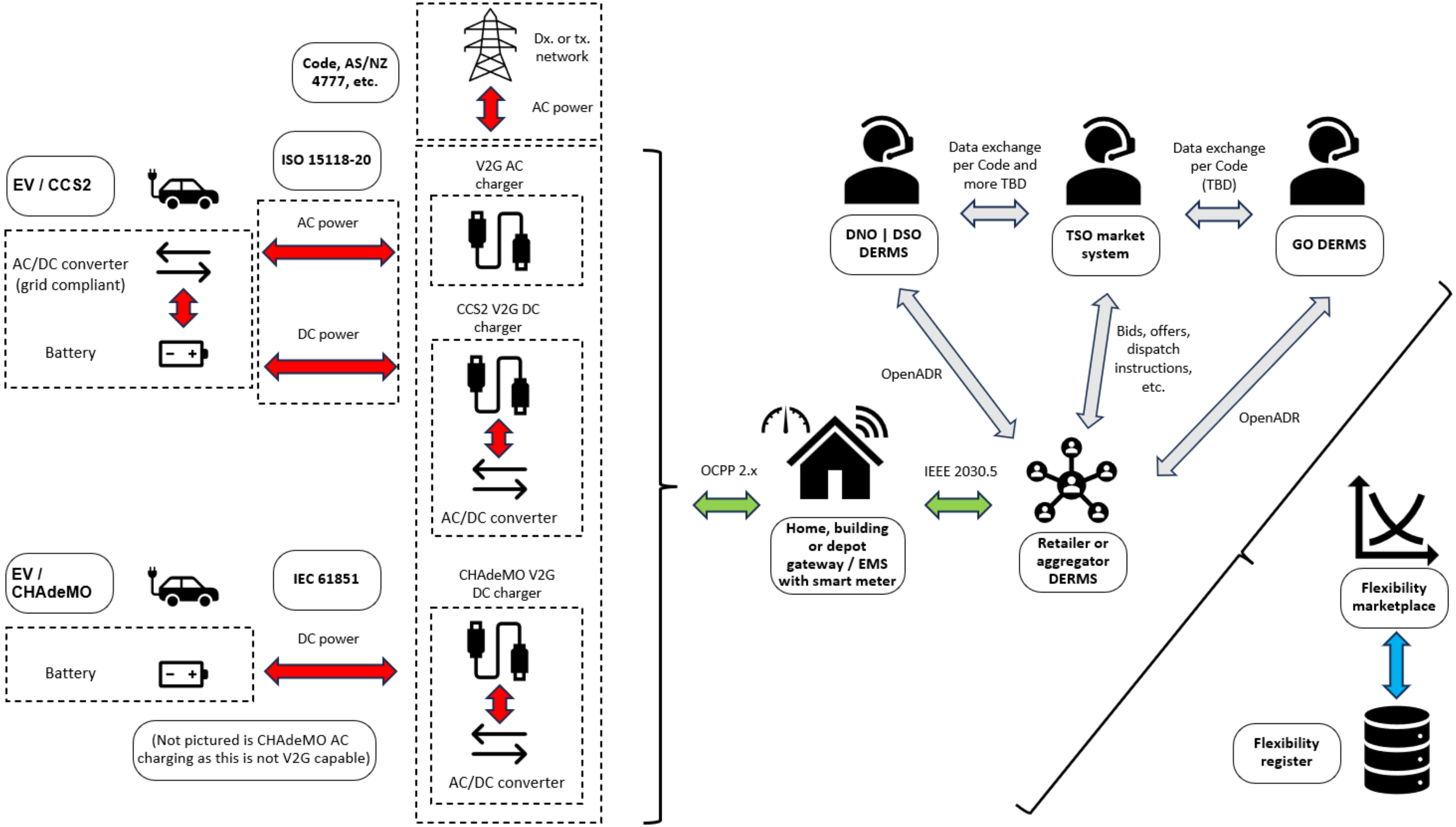
Sections C5 and C6 have thus far focussed on devices being registered, connected safely and incentivised to operate in ways that support efficient network operations and investment.

There (by necessity) has been a significant focus on the preferences and needs of distribution networks. However, once connected, flexibility from DER like V1G and V2G can deliver benefits to a variety of participants in the electricity industry value chain:

- **Transpower as grid owner** – to aid in network deferral through reductions in demand
- **Transpower as system operator** – to manage congestion and bolster ancillary services within the wholesale market through demand response
- **retailers, energy traders and aggregators** – managing their wholesale market position and responding to wholesale market signals in the spot market and ancillary service markets
- **distributors** – to aid in network deferral, congestion management and power quality.

This means numerous parties will have an interest in accessing flexibility from V2G as shown in Figure 33.

Figure 33: V2G configurations



We indicate that distributors, the grid owner and the system operator are likely to access V2G flexibility through retailers and/or aggregators since the latter two parties currently hold and/or are oriented towards building end consumer relationships at scale.

However, it is likely that some parties (as already seen with some distributors enrolling flexible resources into distributor DERMS and Transpower's past demand response trials) will also seek to access consumer flexibility "directly."

The guiding light for such interactions should be for flexibility to be delivered to the highest value use cases within the power system as often as practicable, subject to consumer preferences and network constraints being respected. What is necessary for this to occur are:

- interoperability of communications and control
- suitable (and effective) contractual arrangements.

C9. Communications and control interoperability

Open standards and interoperability from the end consumer's flexible devices (EV and V2G charger) through to upstream parties calling on or coordinating flexibility at scale are essential to preventing inefficient "lock-in" of flexible resources to one use or one user or "lockout" of resources from closed ecosystems.

Interoperability based on common standards also reduces the risk of inefficiencies stemming from numerous and potentially geographically disparate actors (eg, multiple retailers, distributors, aggregators and so on) being unable to coordinate systems, processes and data exchange without bespoke modifications, if at all.

As illustrated in Figure 33 above, some of the relevant standards are:

- **EV and V2G charger** – ISO 15118-20 (for two-way charging of CCS2 vehicles) and IEC 61851 (for CHAdeMO vehicles). ISO 15118-2 may be sufficient for DC two-way charging of some CCS2 vehicles).
- **V2G charger and gateway device** – eg, OCPP 2.x or IEEE 2030.5.
  - *OCPP* is a communication protocol between charging infrastructure and Charge Point Operators or other platforms that manage EVSEs
  - *IEEE 2030.5* is commonly used as a way to control smart inverters, EV chargers and other behind-the-meter assets
  - many homes, businesses and/or Charge Point Operators will not have V2G chargers communicating directly with electricity industry participants upstream. A site gateway (eg, a smart home hub) will instead act as an intermediary for communication between the site's devices and flexibility coordinators further upstream.
- **Gateway device and retailer/aggregator DERMS** – e.g., IEEE 2030.5 or OpenADR.
  - *IEEE 2030.5*-compliant Instructions issued by a DERMS can in some cases be passed through to individual devices via a compliant gateway
  - *OpenADR* is a demand response protocol, favoured by utilities and aggregators to trigger events at sites where flexible devices exist. The gateway device may then coordinate individual assets using IEEE 2030.5 or OCPP and so on. OpenADR has been investigated and demonstrated in New Zealand through the Electricity Engineers' Association's FlexTalk programme.[55]

[55] The EEA leads FlexTalk in partnership with the Energy Efficiency and Conservation Authority and industry. Read reports from the initial trial.

- **Retailer/aggregator DERMS and distributors/system operator/grid owner/etc.** – eg, OpenADR
  - parties like distributors operating their own DERMS could communicate with retailer/aggregator DERMS using OpenADR
  - conversely, retailers and aggregators wishing to interact with the wholesale market will most likely be required to work with the Wholesale Information and Trading System (WITS) and/or the system operator's dispatch web service. This is the standard in New Zealand today for dispatchable generators, loads and ancillary service market (eg, reserves/interruptible load) participants.

Confidence in suitable standards also reduces or removes the need for flexibility market stakeholders (be they regulators, consumers, distributors, retailers, aggregators, etc.) to expend effort in vetting and "whitelisting" specific approved devices and systems.

"Practical" interoperability concerns

A further dimension to interoperability goes beyond mere compliance with communication/control protocols and standards, but "practical, out-of-the-box" interoperability that allows procurers of flexibility to easily ascertain what *power system services* may be deliverable by a particular device.

In other words, the aim is to go beyond assurances that a device will comply with a particular signal using a particular protocol, to a certification of "asset capability" to reliably respond and reach a certain setpoint within a certain time frame.

The Mercury Consortium (an international initiative that is nothing to do with the NZ electricity company) is working on such certifications (using EVSE as a priority class of devices) to provide guidance on what devices might be suitable for particular power system services like fast instantaneous reserves, slower instantaneous reserves and so on.

Figure 34: Examples of Mercury Consortium device certifications[56]

Table 1. Characterization of Mercury levels

LEVEL 1	LEVEL 2	LEVEL 3
• "Super fast frequency" markets • Strict System Operator Regulation	• Fast reserve markets • Strict System Operator Regulation	• "Slower" reserve, Energy markets and DR programs • Low constraint regulation, best business practice
Example program types: FFR, FCR, Dynamic Containment (NGESO), R1/E-Response (RTE), RERT (AEMO), Contingency, Fast FCAS (AUS)	**Example program types:** FRR (ENTSO-E), Terna UVAM, aFRR, DSO Flexibility (UK, DE, IE), Emergency DR (ISO-NE, CAISO), Slow FCAS (AUS)	**Example program types:** mFRR, Day-Ahead/Intraday trading, Capacity Markets, Time-of-Use Shaping, Flex DR (Japan, Korea), Delayed FCAS & Scheduled Lite (AUS)

Table 2. Parameters and requirements of Mercury levels

REQUIREMENT	DEFINITION	MERCURY LEVEL 1	MERCURY LEVEL 2	MERCURY LEVEL 3
Response time	Time from DER-M command acknowledgement by DER to the first updated meter data sent back to the DER-M with an observable change of power	<3 seconds	<20 seconds	<60 seconds
Telemetry time interval	Minimum time interval between consecutive telemetry data transmissions	<1 second	<1 second	<120 seconds
Meter accuracy	Metering data accuracy	2%	2%	2%

Flexibility marketplaces

A flexibility marketplace is a platform for participants to find potential sellers of flexibility – ie, parties who could, for a price, recruit and deploy additional demand response or injection.

In theory, flexibility marketplaces could evolve from:

- bulletin boards – ie, a place for buyers and sellers to advertise
- matching platforms – ie, a bulletin board that also helps match buyers and sellers

56 https://restservice.epri.com/publicattachment/93616

- exchanges – ie, a platform that enable contracts to be formed and executed.

The latter two steps require some degree of standardisation of flexibility products – ie, standards ways to describe the key features of available resource so that bespoke matching is not required.

Examples of such marketplaces include Piclo[57] (operating in Europe, North America and Australia) and Localflex[58] in New Zealand.

In practice, we do not think that flexibility marketplaces are an essential (or high priority) early part of the journey to realising significant value from V2G. The more important early steps are:

- implementing 'type of use' tariffs that create a material payoff (ie, a bill reduction) for enabling V1G and V2P
- ensuring tariff eligibility is open to any service provider and control platform that can deliver required service levels.

This step unlocks enough network and generation value to begin establishing V2P (and NG-HWC) resources at scale. Once enough resources have been recruited, procuring 'deeper' response to target specific network deferral opportunities becomes feasible.

The payoff for deeper response may in turn justify the incremental expense and complexity of going from V2P to V2G.

C10. Respecting network limits

A key issue for V2G at scale is ensuring it operates within safe limits for distribution and transmission networks – including injection limits and demand limits (ie, as resources 'recharge' after injecting).

This issue is less pressing at low penetration, where measures such as capacity band pricing for injection could be sufficient to push back the time when more sophisticated measures are needed.

As penetration grows, additional measure may include:

- improved measurement of power quality and flows at more points within distribution networks – ie, to better understand and monitor network limits and network headroom
- increasing sophistication of 'type-of-use' eligibility criteria to enable closer control of injection 'hot-spots' and rebound peaks (ie, as controlled devices begin recharging post-control)
- implementing enforceable operating envelopes to prevent aggregate demand or injection from overwhelming distribution network limits
- greater communication from distributors to the transmission system operator (SO) regarding local system state and limits – to enable the SO to better understand and manage power system risks.

Transmission system operators (TSOs) have long been managing congestion and ancillary services to maintain power system security on transmission networks in real time.

In contrast, distribution networks have traditionally been built to enable unconstrained usage without any need to manage congestion beyond directly controlling R-HWC. The above steps represent a broadening of the scope of system operation within distribution networks – ie, to manage the increased flexibility (and hence potential for overload) of combined NG-HWC and V2G.

57 https://www.piclo.energy/
58 https://www.ourenergy.co.nz/news/what-localflex-actually-delivers

Appendix D. Commercial platforms

Appendix D provides more detail to support Chapter 5, which discusses commercial arrangements for V2G:

D1. Price structures for V2G

The value from V2G varies significantly on both a temporal and geographic basis:

- temporally, both generation and network value is concentrated in a small number of hours (<1%), with significant weather-driven variability in when those hours occur within-year, and from year-to-year
- geographically, the extent to which peak demand drives network costs varies significantly. Different parts of the network can also have peak demand at different times of the day and year (eg, as between a residential network and a CBD network). Both variations are due to within-network factors such as consumer composition, ICP growth, and network age.[59]

An implication of this is that there needs to be good signalling of when and where V2G is most valuable – to coordinate recruitment of V2G resources and their operation.

Signalling value through pricing structures creates a 'payoff' (in the form of lower bills) that incentivises (and covers the cost of) participation.

This also applies to any other distributed energy resource (DER) that can alter its pattern of demand or injection to meet the flexibility needs of the system.

Efficient and effective price signalling is already achieved for generation through the locational marginal pricing (LMP) operation of the wholesale market, which provides fully-nodal spot prices that vary on a half-hour-by-half-hour basis, and between each of the approximately 200 grid exit points in the transmission network.

However, no such temporally and geographically granular price signalling is currently provided for networks.

In theory, LMP could be extended further to operate at the distribution feeder level. In practice, this is unlikely to be an effective solution, as discussed in Section 94D2.

We think the principal mechanism to incentivise V2G for network purposes is through network tariff design. This section assesses the relative merits of network tariff options in the context of growing V2G (and other flexible resource) penetration.

Other flexible resources include V1G, controlled hot water cylinders, static batteries, and control of other types of appliances (eg, heat pumps or refrigerators). The best tariff design needs to be the best on balance when considering all these resource types.

Although there are many different tariff designs, they can be boiled down to three broad families for addressing the temporal aspect of

[59] Older parts of a network generally have less spare capacity (increasing value) but can also be closer to replacement (reducing value).

network need, and three approaches for addressing the geographic aspect:

1) for temporal signalling, the three key families are:
   a) ***dynamic***, such as coincident peak demand tariffs, that apply a very high charge to demand (and pays a very high price for injection) during the top 'x'% of periods of peak demand on a network for each year. There is no ahead-of-time specification of when these peak demand periods will occur – ie, demand periods are determined dynamically based on actual network conditions
   b) ***static time-of-use*** (ToU) tariffs specify ahead of time when high-priced 'peak' periods will occur, with other 'off-peak' periods having a zero (or near-zero) price. For example, a typical peak period definition is 7-11am and 5-9pm, with variations on whether weekends and summer months are included
   c) ***type of use*** ('TYoU', a.k.a. 'controlled', 'managed' or 'appliance') tariffs provide lower charges for usage by devices that are managed remotely to avoid peaks. The balance of the property's usage is charged using standard tariffs (such as time of use).
2) For geographical signalling, the three key families are:
   a) ***granular network tariffs***, with different prices at different locations based on local capacity headroom and projected upgrade costs
   b) ***pricing areas***, with the same tariffs across broad parts of each network (or an entire network) set at a level that reflects averaged headroom and upgrade costs
   c) ***pricing areas PLUS bespoke top-up procurement***, with the distributor making top-up payments to procure additional response in areas with more imminent (but deferable) need for capacity upgrades.

In deciding on the best approach, there are trade-offs between economic 'purity' and practicality.

We consider the best approach is a combination of:

- type of use (TYoU) tariffs that can be accessed by V1G, V2G, hot water cylinders, and stationary batteries enrolled with eligible service providers to provide a base level of response
- pricing area time of use for other demand
- top-up payments for access to 'deeper' response.

Key considerations in favour of this approach are:

- hot water cylinders (HWCs) and EVs are too flexible to work with time of use pricing (except at low penetration)
- managed HWCs and EVs are flexible enough to eliminate per-household growth in peak demand
- HWCs and EVs are flexible enough to meet network needs while having material residual flexibility to respond to spot prices or provide deeper response to local network investment pressures
- broad pricing areas minimise pricing complexity, while providing a meaningful signal to shape consumer choices
- time-of-use (ToU) is beneficial for avoiding over-signalling the value of off-peak injection, which is particularly relevant to uncontrolled rooftop solar
- the overall pricing 'package' is compatible with a 'just transition'. It does not alter status quo pricing for non-EV households, and for EV households it only allocates additional costs if they opt for unmanaged peak usage (and only makes payments if a

household is helping defer a network investment, which in turn benefits all households)

- dynamic and granular pricing approach, in contrast, produce consumer-unfriendly volatile electricity bills.

Time of use (ToU) pricing

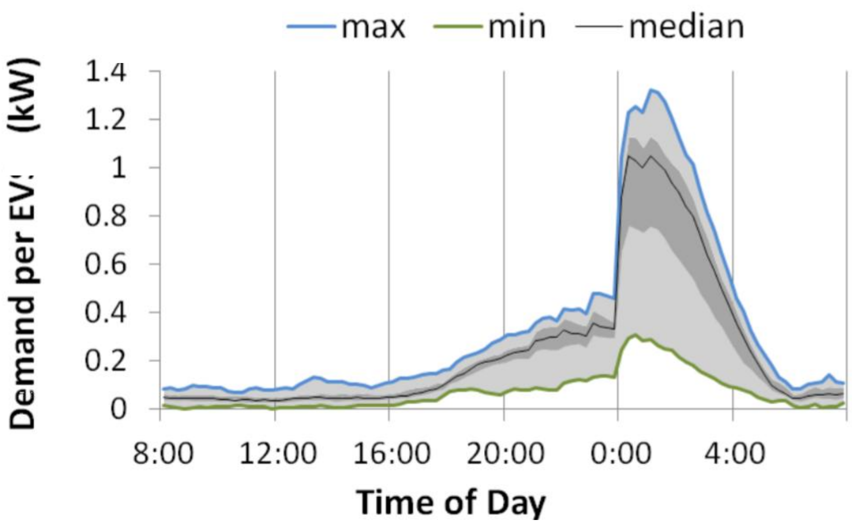
While time of use is probably the best option for encouraging general mass-market consumer behaviour changes (eg, postponing putting the dishwasher or washing machine on until late in the evening) and appliance choices (eg, choosing more efficient light bulbs and heating options, and not over-building rooftop solar) it is inappropriate for delivering good outcomes for storage technologies such as EVs, hot water cylinders, and static batteries.

Ironically, it is the very controllability of storage technologies such as EVs and hot-water cylinders that means ToU is unlikely to be the best long-term solution for these technologies.

There is a very real risk of consumers responding to the price signal of a ToU tariff and using timers (built within the control functionality of every EV, or simple add-ons for hot-water cylinders) to start charging at the start of the off-peak period. In doing so, all the natural diversity of households charging at broadly different times would be lost, and a significant new peak could develop.

Experience with ToU tariffs illustrates such outcomes are likely. This has occurred in New Zealand historically with networks applying ToU pricing for hot water control.[60] It is also illustrated in this example shown in Figure 35 below for San Francisco, where Pacific Gas & Electric offered EV-owning customers a time-of-use price with an off-peak period starting at midnight.

Figure 35: Weekday EV charging demand for San Francisco



Note: The x-axis starts at 8am

We analysed this further in our 2018 "Driving Change report,[61] with quantitative analysis demonstrating that large-scale EV uptake with simple ToU pricing applying to EVs would likely result in higher peaks than if consumers just faced a flat price and had the increased peak demand associated with uncontrolled EV charging.

These previous analyses only considered V1G – ie, altering the pattern of EV charging. V2G super-charges the adverse effects of ToU tariffs with symmetrical rates for paying for injection at peak at the same rate as charging consumption at peak.

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60 For example Orion had ToU rates in the late '90s and early 2000's and experienced localised peaks as hot water cylinders all came on at once.

61 *"Driving change – Issues and options to maximise the opportunities from large-scale electric vehicle uptake in New Zealand"*, Prepared for Orion, Unison, and Powerco, 7 March 2018. Available for download at https://www.concept.co.nz/updates.html

To illustrate this, and as detailed in sub-section D3 later, Concept built a simple model to examine the potential outcomes if vehicles with V2G capability were to respond to a ToU tariff structure.

The modelling illustrates the enormous earnings consumers could achieve from providing V2G in response to a ToU signal, even though most of the time the V2G is not required and the secondary peak that will occur at the end of the evening peak period will rapidly grow to be substantially larger than the current network system peak – in other words, V2G consumers responding to a ToU tariff would be rewarded despite *increasing* peak demand.

As EV uptake starts to really take off, because V2G is so cheap to enable, this points to ToU structures with symmetric injection/consumption charges becoming increasingly problematic.

Based on the problems with coincident peak demand and ToU tariffs, we think type of use (TYoU) tariffs are the best approach for delivering both V2G and V1G.

Type of use (TYoU) tariffs

A type of use tariff provides a lower price for a particular type of usage in return for allowing some level of control.

Type of use tariffs have been a long-standing feature of network and retail pricing in New Zealand. Many distributors (and retailers) have traditionally offered such tariffs for ripple-controlled hot water cylinders, and for night store heaters.

There are two main ways of constructing cost-reflective appliance tariffs:

- zero (or low) peak charge for the controlled appliance
- higher fixed charge for property with uncontrolled appliance

The rationale for the peak charge approach is that a controlled appliance does not add to peak demand at times of network stress – ie, the distributor can ignore the controlled appliance when planning network capacity upgrades. This means the distributor does not need to signal the cost of upgrading the network.

From a consumer point of view, this approach means:

- they can plug-in and consume anytime (including at peak) with no network cost – however, the trade-off is that their usage may be interrupted on some days
- the payoff from opting for a controlled tariff depends on the strength of the signal being sent in the peak charge – ie, it is automatically aligned with the distributor's general peak signal.

To implement the peak charge approach, the distributor needs consumption information for the controlled appliance. Since this is only used for network billing (with the ICP meter still used for energy settlement) a distributor may be happy with EVSE or in-car metering.

The rationale for the fixed charge approach is that a network designed to accommodate uncontrolled at-home faster charging would be designed differently from a traditional residential network and would have higher fixed costs.

This means the lower-bound of the subsidy-free cost recovery range for such a network is higher than the lower-bound for a traditional network. In other words, the revenue per customer may need to be higher to avoid creating a subsidy.

To implement the fixed charge approach, a distributor needs subsidy-free range estimates for each network type (to inform the difference in rates) and then needs suitable tariff assignment processes. For example, the distributor may wish to assign any ICP with a non-controlled 7 kW EVSE to a separate consumer group.

The need for tariff assignment is common to both approaches. This process could include:

- peak tariff assignment as part of the enrolment process for load control – whether the distributor's own control scheme or an acceptable third-party control scheme
- distributor acceptance of metering arrangements as part of its own control scheme, or as part of accepting third-party control schemes
- periodic re-validation of tariff assignment, or obligations to notify when opting out of control scheme
- a requirement for consumers to notify the distributor if installing high-capacity EVSE
- consumer information (at time of notification) regarding options and costs associated with controlled and uncontrolled usage
- fixed tariff assignment on notification (higher tariff) and enrolment (lower tariff).

In each case, distributors should take care to ensure requirements are not unnecessarily onerous. The aim is to achieve broadly cost-reflective signals for most consumers, not to ensure absolute accuracy.

A potential advantage of the discounted peak approach (as opposed to the increased fixed charge) is that it better incentivises consumers (and their retailers) to ensure their distributor allocates them to the correct tariff.

Standardisation

Network pricing structures have relatively light-handed regulatory oversight in New Zealand, which has led to a widely diverging approaches.

The growth of EVs, and the prospect of V2G, strengthens the case for increasing alignment between networks – ie, to better enable nationwide markets for EV (and next-generation hot water) management services.

D2. Distribution LMP

The economically pure approach to signalling the need for, and rewarding the provision of, DER flexibility would be to have dynamic pricing applied at a very geographically granular level – for example at each zone substation, distribution substation, or distribution feeder (in ascending granularity).

There are then two broad approaches:

- market prices – prices are discovered through some form of auction process
- administered prices – prices are determined based on an assessment of the relevant opportunity cost.

Market-based dynamic prices are used to coordinate use of the transmission grid. This involves:

- a centralised auction and dispatch process operated by Transpower's system operator
- a network capacity offer maintained by Transpower's grid operator
- generators with diverse short-run operating costs who actively construct offers that reflect those costs (as well as some load parties who actively bid or otherwise respond to price signals to reduce load at times of high prices)
- an auction engine that optimises use of available grid and energy resources – finding the least-cost, secure dispatch solution that respects grid capacity limits, publishing locational marginal prices (reflecting the cost at each node of adding a unit of demand) and issuing enforceable dispatch instructions

- a grid investment approach that optimises capacity to a level that is consistent with congestion being managed (and access rationed) via the above auction and dispatch arrangements.

This system is more sophisticated and intensive than most electricity systems worldwide, but works and delivers value because:

- participation costs are not too onerous relative to the size of the participating resources
- the real-time energy optimisation task delivers significant value – there is material scope to optimise between dispatchable resources with disparate, time-varying costs
- there is material scope to optimise energy resource investment – influencing the generation technology mix and demand choices
- there is material scope to optimise grid capacity investment – the total system cost of a grid that optimises congestion is significantly lower than the cost of building an uncongested grid.

The nodal prices produced by this system provide a 'heartbeat' that has a pervasive impact coordinating operation and investment in energy resources and grid capacity.

Distribution networks are connected to grid nodes with local (or nearby) prices that provide a granular, real time, transparent signal of the cost of supplying energy at that transmission node location. The signal includes transmission grid cost – ie, all the losses and congestion that impact supply to that node.

Parties with resources located within distribution networks are exposed to the local transmission nodal price and can participate in the price discovery process (if large enough). However, because there are no pricing nodes within distribution networks, the current system cannot optimise distribution network constraints.

In theory, this could be addressed by extending nodes into distribution networks. For example, adding a node at a key zone substation would enable optimisation of congestion in the sub-transmission lines between the grid exit point and that zone substation.

For that to be worthwhile, would require an incremental uplift (compared to alternatives) in optimisation of the sub-transmission line that outweighed the incremental cost of establishing and operating the auction node. The mechanism for this would have to involve:

- more optimal deployment of dispatchable resources
- efficiency-enhancing response by other resources to the price signal – in terms of operation and investment choices
- an ability (and incentive or willingness) of the distributor to defer investment in the capacity of the sub-transmission line.

The last point involves a potentially significant 'leap of faith' on the part of the distributor, since capacity upgrades must be committed (or not) years ahead of projected need.

Even in the transmission system, reliance on price-based rationing as a substitute for prudent capacity investment is limited – all larger grid exit points are part of the 'core grid' and are subject to a deterministic planning standard. This means in practice that:

- planning for capacity investment is based on observed demand, which is in turn influenced by the existence and operation of nodal prices, but
- Transpower is required to invest in capacity at a level that does not rely too heavily on price-based congestion management.

This makes sense when considering the very high cost to consumers when price-based rationing reaches its limit and the operator has to resort to forced demand curtailment (or loss of supply).

Given these unforgiving consequences, and the uncertainty inherent in grid planning timeframes, prudent investment ahead of need is a well-grounded norm. In this context, the main roles of pricing (from a network perspective) are to help:

- condition the structure and level of demand in the lead-up to network investment decision-making – generally pushing back the timing that would be needed if demand were not so conditioned
- provide a useful part of the toolbox for rationing capacity at times of network stress.

It seems unlikely auction-based price discovery at nodes within distribution networks could deliver sufficient incremental benefit to warrant the associated cost and complexity. Compared to grid pricing:

- the incremental benefit would only relate to the value of extra signalling and rationing over and above that provided by the price at the local grid pricing node. Generally, the local grid pricing node will already provide a broadly useful signal for conditioning local demand
- to provide a signal that's different from the local grid node, the distributor would need to elect to defer investment in favour of allowing their network to congest. This is a non-trivial change in asset management and would likely require new regulatory tools (analogous to Transpower) to govern major capacity investment decision making
- to achieve meaningful price discovery, the network would need to have sufficient resources that are flexible, dispatchable, have varying opportunity cost, and a cost-effective method for participating in the auction (which may include via aggregators)
- the scale (and cost) of price-responsive curtailment would need to be large enough to enable cost-effective (and prudent) network investment deferral. This is more challenging to achieve when rationing capacity for load (which has a very high opportunity cost) than for generation access.

The prospect of auction-based price discovery being worthwhile becomes more tenuous deeper into the distribution network, as the flexible resource pools shrink and the (additional) avoidable investment costs reduce.

In contrast, administered dynamic prices:

- bypass the costs associated with the auction process
- replace price discovery with (likely less accurate) opportunity cost estimation.

The key question then is how dynamic prices should be in light of their inherently limited accuracy weighed against the potential to elicit more targeted response.

D3. V2G response to ToU structure

We developed a model to examine likely outcomes if vehicles with V2G capability were to respond to a ToU tariff structure that had a symmetrical pricing approach for paying for injection versus charging for consumption at times of peak.

The model was designed using a typical non-EV residential demand profile as the starting point (specifically, the Rolleston feeder in Christchurch). Initial model assumptions were:

- after-diversity average non-EV residential contribution to peak demand = 2.5 kW
- network LRMC = $150/kW/yr
- peak/off-peak ToU tariff structure with peak being defined as the periods from 7-11am and 5-9pm every day

This resulted in a peak tariff charge of 13.4 c/kWh (excl. GST) and an off-peak charge of 0 c/kWh, and a resulting variable component of a typical non-EV residential bill of $375/yr (excl. GST).

The EV specifications were:

- usable battery storage capacity ≈ 40 kWh (ie, typical of models such as the Hyundai Ioniq 5, factored by not charging above 80% and not letting the battery get lower than 10%)
- EVSE (wall-charger) capacity = 7.4 kW
- average annual km travelled (VKT) requiring charging at home ≈ 14,300 km
- vehicle efficiency = 17.5 kWh/100km
- 'round trip' battery losses (ie, the electricity lost from charging then discharging a battery) = 10%
- time vehicle in garage = 5.30 pm to 8am on Weekdays, 5pm to 10.30am on Weekends

We programmed an operating logic that if the vehicle in the garage, it will charge if the battery is not full, except if it is a peak period – in which case it will inject. Injection will only occur to the extent there is available battery capacity, plus an additional constraint on injection during morning peaks that it will not reduce the battery charge below three times what the vehicle would need for a typical day's travel.

Using the above parameters, the net cost to the consumer from charging the vehicle is that they would *earn* $1,500 from the network tariff, plus earn an additional $50 from wholesale prices[62] – all excl. GST. This result is because all charging occurred in network off-peak periods where the network tariff was zero, and material amounts of injection would occur in peak periods. In effect, the EV battery operates to arbitrage the peak/off-peak price signal, even though for the majority of the time such injection is not required.

The equivalent earnings for a static battery such as the Tesla Powerwall 3 would be $1,200 for network charges and $41 from wholesale.[63]

Earnings of this scale would likely significantly encourage uptake of V2G EVSE chargers. It would deliver 1-year payback for the lower-cost chargers for modern EVs with grid-compatible on-board chargers, and 2 to 3-year payback for chargers for EVs that don't have grid-compatible OBCs. In contrast, it would take ≈13.5 years to payback the cost of a Powerwall purely from network and wholesale tariff arbitrage.[64]

While uptake of V2G capability is a good thing, doing so through ToU tariffs will actually create big problems, in that a new – and much larger – peak will occur at the time the evening ToU peak period ends.

For example, if just 3% of households have an EV and use V2G to respond to a ToU signal, the secondary peak that will be caused at the end of the evening peak period will be approximately 27.5% *higher* than the current evening peak. In contrast, this level of peak demand increase if consumers charged their EV through dumb charging would not occur until almost 25% of consumers have EVs.

62 For this model, wholesale prices were assumed to have the same average within-day and within-year shape as historically.
63 The Powerwall was assumed to have a usable storage capacity of 13.5 kWh and an inverter capacity of 10 kW.
64 Assuming a Powerwall cost of $19,000, incl GST. Source: https://www.mysolarquotes.co.nz/blog/solar-battery-information/tesla-powerwall-3-less-style-but-more-substance/

D4. Coincident peak demand pricing

This involves applying a $/kW rate for consumption during actual periods of system peak demand, whenever they may be. Typically, the Coincident Peak Demand (CPD) rate would be applied during the top 50 or so hours of system peak in the year, although a much tighter period can be used (e.g. the top three half-hours). This compares with 'peak' periods in a typical ToU tariff covering 2,807 hours (4 hours in morning and 4 hours in evening, every day of the year).

Because peak costs are being spread over such a small number of time periods, the effective $/kWh cost of consumption during these peak periods is significantly higher than the $/kWh charge for a typical peak period under a ToU pricing approach. For example, a cost-reflective peak-period ToU price could be of the order of 12 cents/kWh, whereas an equivalent coincident peak charge applied over the top 50 hours of the year would be $2.65/kWh – twenty-two times as much.[65]

The Lines Company (the network company serving the King Country) introduced CPD pricing in 2007. However, following significant public and political disquiet with its consequences, it dropped the approach in 2018. No network company or retailer currently implements CPD pricing in a form that results in mass-market consumers facing such price signals.

The experience from The Lines Company's implementation of CPD pricing highlights consumers find it harder to understand than simpler tariff approaches such as ToU pricing. This difficulty in understanding, coupled with the extreme prices during CPD periods and not knowing in advance which of the 50 or so hours in the year are going to be classed as system peak, can create significant uncertainty and fear among many consumers – as was the experience with The Lines Company.

A pricing approach that is hard to understand is less likely to deliver good consumer decisions – as was evidenced by the Electricity Authority's review of The Lines Company's pricing. And a pricing approach that is mis-trusted or feared by consumers is unlikely to be politically durable – as was evidenced by The Lines Company eventually moving away from CPD pricing.

Further, in terms of trying to positively influence consumer decisions, our past analysis[66] demonstrates that there is little to no difference between CPD and ToU pricing options in terms of the economic price signal regarding:

- what appliances to buy (eg, whether to convert to LED lighting, from gas to electric heating, or from a fossil to electric vehicle)
- what regular patterns of use to encourage.

Options are equivalent for sending a price signal for consumer appliance purchases – but CPD may be practically worse

The price signal for consumers deciding on appliances is equivalent between CPD and ToU pricing. This is because the relative proportions of demand from the different appliances during periods classed as peak in a simple ToU structure are very close to the relative proportions of demand from the different appliances during the periods of absolute peak network demand. This is a key insight and is crucial to appreciating the effectiveness of different options for delivering appliance investment signals.

65 The increase in effective $/kWh price is not simply based on the ratio of the number of hours over which peak is defined for each approach but must also take account of the typical profile of demand during these peak periods. This example was calculated using actual half-hourly consumption data for a network.

66 "*Issues and options for moving towards more cost-reflective network tariffs*", available on request.

The only appliance where CPD is almost always going to send a stronger signal than a ToU structure is space heating. This is because space heating is the activity that is most strongly associated with extreme peak demands. However, this difference in signal between CPD and a ‘reasonably’ structured ToU is one of degree, rather than being fundamentally different.

We consider there are also adverse social consequences (including to human health) of having a tariff that gives rise to some consumers (generally the most vulnerable) being afraid to turn their heating on.

The Electricity Authority’s review of The Lines Company’s experience with CPD pricing also found that many consumers found it confusing resulting in them making the wrong appliance choice.

As for type of use tariffs, these can send an equivalent price signal to ToU or CPD by suppliers setting an appropriate discount for consumption from the managed appliance.

Options are equivalent for encouraging regular patterns of consumption – but CPD may be practically worse

A simple, understandable ToU structure is easy for consumers to develop regular patterns of use around – eg, postponing running the dishwasher till later at night.

Under a managed appliance option, there is no need to encourage patterns of consumption, as the supplier will manage that aspect.

Again, CPD pricing could theoretically encourage regular patterns of consumption. However, if consumers find the pricing hard to understand, they may also be less efficient at developing the best consumption patterns.

For incentivising dynamic response when and where it is required, CPD is theoretically better than ToU, but worse than type-of-use (TYoU) tariffs

The only area where CPD is theoretically better than ToU is in encouraging dynamic load shifting during the few periods of actual peak demand.

However, this requires significant management overhead by consumers to respond to, significantly degrading their effectiveness (while also increasing consumer stress).

Type-of-use tariffs will inherently be far superior to CPD at delivering high levels of appliance response during periods of system stress as service providers will be much better able to coordinate the level of response required at different times and locations rather than rely on individual consumers responding.

In summary, CPD pricing may be theoretically ‘right’, but practically very ‘wrong’

All in all, while CPD pricing may be appropriate for a handful of large industrial consumers who have the resources and expertise to meaningfully respond to such signals, we believe it is completely inappropriate for the vast majority of consumers.

Appendix E. Insights from V2G trials

Appendix E summarises V2G trials from overseas and New Zealand. These include:

E1. Summary

- The greatest opportunities for V2G to start to be offered on a commercial basis (ie, not just experimental trials), are in situations where V2G doesn't require the addition of an external converter, ie:
  - later-generation light vehicles which have on-board chargers that can provide grid-compatible power, thereby enabling low-cost external AC chargers (eg, as offered by Renault in France and the UK for customers buying their later-generation Renault EVs)
  - heavy vehicles that require external DC chargers anyway.
- some heavy trucks use cases seem ideally suited to providing V2G because:
  - most will likely require DC charging
  - they can potentially provide large amounts of power per vehicle
  - many such vehicles will anyway be parked at their base during the critical evening peak periods when electricity systems are under greatest stress eg, rubbish trucks (UK trial).
- V2G has been proven to provide sufficiently fast response for offering Ancillary Services to support the grid (as demonstrated in trials in Australia and South Korea)
- V2G does not materially degrade recent EV batteries, and may actually be beneficial. A real-world trial in South Korea demonstrated that over the typical lifetime of a car in New Zealand (approximately 220,000 km) there is negligible difference in the State of Health of batteries for vehicles engaged in V2G compared to V1G. Indeed, some researchers have concluded that EV battery life can be improved through managed bidirectional V2G charging by keeping the EV battery at a more optimal state of charge while it is not in use and managing battery temperature.

Worldwide, more than 150 V2G projects involving over 12,000 EVSE are recorded in the V2G Hub[67] database. This section of the study highlights some of the more recent significant global V2G projects, including those using AC V2G charging with CCS vehicles, and also summarises the V2G trials that have occurred in New Zealand.

E2. South Korea – KEPCO and Hyundai IONIQ 5

Korea Electric Power Corporation (KEPCO) has developed a bidirectional On-Board Charger (OBC) for use in EVs, with a rating

[67] https://www.v2g-hub.com/insights#graphs

of 11 kW for charging and 5 kW for discharging. This has been installed in Hyundai IONIQ 5 EVs from 2021. KEPCO has also developed an AC V2G EVSE allowing the EV battery to charge at 7 kW and discharge at 5 kW. KEPCO recruited 100 Hyundai IONIQ 5 EVs for a V2G demonstration programme, with around half the participants being private EV owners, and half being car rental companies and other fleet participants. All EVs in the V2G demonstration programme had a firmware upgrade with the draft version of the ISO 15119-20 communication protocol (which at that time was still under development) to enable the V2G functionality, following KEPCOs long term testing of how the EVs and the EVSE worked together[68].

To use distributed EVs to their full potential as a flexibility resource, they need to be able to work together as a single large battery, or virtual power plant. This requires simultaneous control of all chargers and the ability to respond quickly. KEPCO tested the transition time for aggregated control of multiple EVs which showed that the time to switch from charge to discharge or vice versa using ac V2G chargers was approximately 6 seconds.

KEPCO have determined the round-trip efficiency of the AC V2G with an EV as >84% and compared this with their figures for the round-trip efficiency of a stationary Battery Energy Storage System (BESS) at >81%. They also compare this with the round-trip efficiency of the 800 MW Yecheon pumped hydro system in Korea as 72-81%.

E3. Netherlands - Renault 5 E-Tech in Utrecht

We Drive Solar, Renault and MyWheels have commenced a trial that will see 500 Renault car share vehicles with public AC V2G charging in the city of Utrecht. The first 50 car share Renault 5 E-Tech EVs began sending power back to the grid in June 2025 when parked in public areas and plugged into public AC charging as part of their normal car share service operations.[69]

The project uses 7-22kW AC V2G Mobilize Powerbox Verso bi-directional charging stations developed by Renault.[70] The trial will be the first time that the V2G will be used with public charging infrastructure, which in Utrecht is operated by We Drive Solar. While any EV with CCS2 charging can use the charger for AC charging, only EVs with an on-board bidirectional charger such as the Renault 5 EVs used by the Netherland's largest car share operator, MyWheels, can discharge power through the Powerbox Verso. Renault estimates that the 500 bidirectional EVs could provide 10% of the needed flexibility in Utrecht Region to meet peak-hour demand using solar- and wind energy stored in the EV batteries.

The car share operator, MyWheels, sends a signal to the V2G system to let it know when an EV battery needs to be charged by ready for a customer, and the V2G system creates a charging-discharging schedule based on local electricity market prices.

V2G services are now being offered by Renault to the general public in France[71], outside of a V2G trial, with plans to offer the service in the UK next. The integrated offer consists of four components: a Renault EV with an on-board bidirectional charger (such as the Renault 5 E-Tech), a Mobilize Powerbox Verso bidirectional charging station, a Mobilize energy contract, and a mobile phone app for individual control. Mobilize also install the charging station at the vehicle owner's property to ensure full compatibility.

68 https://www.researchgate.net/publication/375176279
69 https://wedrivesolar.com/utrecht-becomes-europes-first-city-with-a-vehicle-to-grid-v2g-car-sharing-service/
70 https://www.mobilize.com/en/wearemobilizers/the-new-connected-charging-point-mobilize-powerbox/
71 https://media.renaultgroup.com/mobilize-powerbox-the-charging-station-produced-in-france-by-lacroix-and-marketed-by-the-renault-network/

E4. Veolia rubbish truck V2B in the UK

The larger batteries of heavy vehicles provide an opportunity to deliver more power back to the grid than light vehicles, making it more cost effective to use DC bidirectional EVSE. Other heavy vehicles which have schedules suited to ideal V2G opportunities include rubbish and recycling collection trucks. These vehicles have been early adopters of EV technology, due to their stop start driving nature and need for quiet operation in the early morning in residential areas.

In the UK, Veolia has successfully demonstrated the return of 110kW for more than two hours from two electric rubbish trucks to a building on the site where they were parked. The electric rubbish trucks were modified for bidirectional charging by Magtec, which produces electric drive trains including for retrofitting buses and trucks to battery electric operation.[72] The trucks were equipped with CCS2 charging ports and the Velox DC bidirectional charger was manufactured by Turbo Power Systems. Veolia now plans to expand the V2B trial to a V2G trial with council rubbish collection trucks operating in Westminster in London.[73]

Veolia estimates that the electrification of its 1,800 vehicle rubbish collection fleet to V2G-capable battery electric vehicles will allow them to provide 200MW of flexible power capacity daily in the UK, the equivalent of the evening peak energy demand of more than 150,000 homes.[74]

E5. Australia - Realising Electric Vehicle-to-Grid Services

In this trial, 51 Nissan Leafs (CHAdeMO) in fleets using 51 Wallbox Quasar 1 DC bidirectional chargers in 11 locations around Canberra and provided response to 6-second, 60-second and 5-minute contingency frequency control ancillary service (FCAS) raise and lower markets during 2021/22.[75]

Each FCAS event required around 10 minutes of discharge, which was only a very small amount of the EV's battery capacity. The total energy exported from EVs was 0.79% of total charging energy as the trial vehicles were rarely called upon to provide FCAS services. Despite this, in they could have earned an average of A$12,000 per vehicle in 2022, with the majority of potential revenue potentially coming from the NSW FCAS (had EVs been legally able to bid in). Since 2022 the market price for FCAS has fallen dramatically because of the addition of several large-scale batteries, so today revenue for FCAS provision would be around 100 times lower[76]. However, the cost of the V2G DC charger used in the trials was around A$10,000, which is significantly higher than a smart AC wall charger at around A$1,000.

The trial findings included that EVs were often fully charged when FCAS were required, so charging behaviours need to be managed to ensure enough headroom to participate in the FCAS lower markets. The trial also found that participation in the contingency FCAS market is unlikely to have significant impact on driver experience and EV battery degradation as, per event, the energy exports were around 2% of the EV's battery capacity.

72 https://www.utilitydive.com/news/electric-refuse-vehicle-to-grid-veolia-win-waste-dsny/710571/
73 https://www.veolia.com/en/our-media/press-releases/veolia-successfully-completes-pioneering-v2g-trial-uk-waste-collection
74 https://www.turbopowersystems.com/helping-to-power-veolias-4-billion-euro-decarbonisation-pledge/
75 https://arena.gov.au/assets/2024/02/ARENA-Vehicle-to-Grid-Insights-Final-Report.pdf
76 https://arena.gov.au/assets/2025/02/National-Bidi-Roadmap-BACKGROUND-PAPER-2025-02-12.pdf

On 13 February 2024, a grid contingency in Victoria saw 16 of the 51 trial vehicles provide a real world response to a grid event.[77] The 16 EVs were all plugged in, with four actively charging and the others idle. Within 60 seconds, the 16 EVs were exporting a combined 107kW, for a total of 10 minutes in line with electricity market rules. This was one of the first times in the world (if not the first) a vehicle-to-grid response to a real grid emergency has been demonstrated.

E6. UK Octopus Energy and BYD initiative

In June 2025, Octopus Energy in the UK announced a bundled V2G package which includes a leased V2G-ready BYD Dolphin, a bi-directional Zaptec Pro charger (including standard installation) and a tariff that provides free home charging over the EV lease provided[78]. Home owners need to plug in for 12 hours a day for 20 days per month and have the ability to override a V2G session and select a minimum State of Charge that the EV does not go below. Home owners need to apply for a grid export licence, which can take up to 3 months to obtain in the UK.

The Octopus "*Power Pack Bundle*" costs £300 a month, equivalent to NZD 675 per month. (Note that BYD in New Zealand has said that the BYD direction for V2G in the future is with using DC chargers only and the BYD vehicles provided to Octopus are unique to this trial only).

E7. V2G trials in New Zealand

There have been a number of small scale V2G/H/B trials in New Zealand, most using Nissan Leafs or Mitsubishi Plug-In Hybrid EVs (PHEVs) with CHAdeMO charging ports. These trials are summarised in Table below.

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77 https://theconversation.com/when-transmission-lines-fell-16-electric-vehicles-fed-power-into-the-grid-it-showed-electric-vehicles-can-provide-the-backup-australia-needs-230673

78 https://octopusev.com/resources/news/octopus-and-byd-make-waves-with-all-inclusive-car-and-v2g-charging-bundle

Table 5.6: NZ V2G trials

Trial lead	Year	Vehicles	Charging	Location	Key findings
Vector	2019	1 x Nissan Leaf (CHAdeMO)	Smart charger + V2H unit	Piha	V2H – *report on project requested from EECA*
Northpower	2020	1 x Nissan Leaf (CHAdeMO)	6kW Nichicon V2G DC charger	2 test sites	V2G worked as intended when power level exceeded the house load to export the excess to the grid. In a power cut V2H worked but the change-over is not automatic and a 12 Volt ancillary supply was needed to initially power up the charger. V2G worked as expected in conjunction with PV generation, with options to either export to the grid once the EV battery was full, or to draw power from the EV when the PV output was less than the house demand.
Counties Energy					The pilot is ongoing and, following a failed trial with a DC V2G EVSE they have pivoted to trialling an AC V2G EVSE
Mitsubishi Motors NZ	2022	1 x Mitsubishi Outlander PHEV (CHAdeMO)	7kW DC Wallbox Quasar	Porirua	V2B – bidirectional charger which required manual used could not work in a power cut as there was no way to prevent flow back from battery to grid with that generation of technology
Octopus Energy			7kW DC Wallbox Quasar		
Meridian Energy	2023	2 x Nissan Leaf (CHAdeMO)	7kW DC Wallbox Quasar	Christchurch	DC charger complied with AU/NZ4777. Network approval was a standard process. Followed the solar connection process which was already familiar to Meridian. Installation and operation of the charger was relatively seamless, but high cost of this early unit meant limit value to customers
Mitsubishi Motors NZ	2025	CHAdeMO	Nichicon V2G	Porirua	Trial commencing in mid-2025 at Mitsubishi Motors in Porirua
Lightforce Solar	2025		7 kW DC Halo V2G		

In addition to the trials in Table 5, the Queenstown Electrification Accelerator is working with EECA to commence a pilot project deploying 30 - 40 V2G chargers in Queenstown with households and businesses using CCS2 vehicles. The pilot is expected to start in late 2025.

E8. Impact of V2G on EV battery life

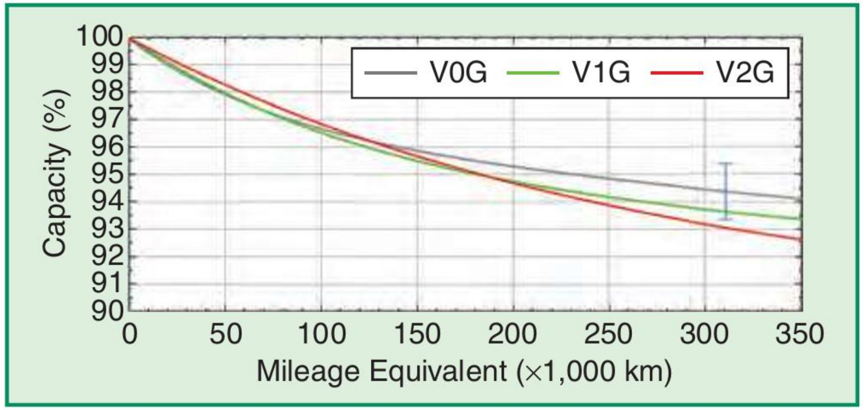
Over time, lithium-ion batteries lose capacity as a result of two degradation mechanisms: calendar ageing (time) and cyclic ageing (number of charge and discharge cycles). Calendar ageing is also influenced by temperature and state of charge (SoC).[79] Specific battery chemistries have different degradation characteristics.

Early studies examining the impact of V2G on EV battery life were based on vehicle batteries like the first-generation Nissan Leaf (which has no active battery cooling) and simple battery cycling models and concluded that battery replacements would be needed if using V2G, negating V2G benefits to EV owners. However, battery technology has progressed, and more recent studies have shown reduced impact of V2G on EV battery life.

The V2G trial described in Section E2 includes a study of the Hyundai Ioniq 5 EV batteries' State of Health (SoH) through thousands of charge-and-discharge cycles. In parallel to the V2G trial, a long term continuous comparative test of dumb charging (V0G), managed charging (V1G) and charge-and-discharge control (V2G), using the same battery modules as in the IONIQ 5, showed a difference of less than 2% in SoH between the different charging types over cycles equivalent to an EV driving 350,000 km. The results of the test are shown graphically in Figure 36. For reference, the average lifetime mileage or a car in New Zealand before it is scrapped is approximately 220,000 km.

The data in the graph suggests that under 100,000 km, bidirectional charging results in *less* battery capacity degradation than dumb and smart one-way charging. Other researchers have concluded that EV battery life can be optimised through managed bidirectional V2G charging[80] by keeping the EV battery at a more optimal state of charge while it is not in use and managing battery temperature.

Figure 36: Battery capacity degradation due to charge control method[81]



Real-world EV use has also shown overall battery degradation to be lower than previously anticipated, and well beyond battery warranty periods.[82]

79 In simple terms, state of charge tells you how fully the battery is charged relative to its maximum capacity – analogous to a fuel gauge in an ICE vehicle.
80 https://www.sciencedirect.com/science/article/pii/S0360544217306825
81 https://www.researchgate.net/publication/375176279_A_Grid-Friendly_Electric_Vehicle_Infrastructure_The_Korean_Approach
82 https://www.p3-group.com/wp-content/uploads/2024/11/241125_Whitepaper_SOH_EN.pdf

EV battery warranty periods in New Zealand are commonly 8 years or 160,000 km with some EV makes offering longer warranties of 10 years or 250,000 km, such as MG[83] and Mercedes-Benz EQE and EQS models.[84]

Major EV battery manufacturer, CATL, now offers 800,000 km 8-year battery warranties for passenger vehicles[85], and has bus and truck batteries with stated lifespans of 15 years and 2.8 million km.[86]

That said, V2G will void most vehicle manufacturers today and it is yet to be seen how vehicle manufacturers will approach warranties in the future regarding V2G.

83 https://mgmotor.co.nz/owners/warranty/
84 https://www.mercedes-benz.co.nz/passengercars/services/warranty.html
85 https://www.catl.com/en/solution/passengerEV/
86 https://www.catl.com/en/news/6288.html