new energy technology, policy & strategy

Network tariffs for V2G

22 February 2024

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Disclaimer

This report was commissioned by the Australian Renewable Energy Agency (ARENA). The report presents the findings of enX, which was prepared to provide analysis of how network tariffs can incentivise V2G while reducing pressures of electricity grids.

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Executive summary

The scope of this report

This report was commissioned by the Australian Renewable Energy Agency (ARENA) to explore the role of alternative network tariff arrangements in supporting vehicle-to-grid (V2G) operation, and how they contribute to outcomes for EV owners the electricity grid.

While V2G is largely nascent in the Australian market, it is an opportunity we need to prepare for. enX has previously estimated at the storage capacity in Australia's EV fleet will exceed all other form of storage in Australia's national electricity market (NEM) by the mid 2030's. Unlocking a small proportion of this capacity in the form of V2G could result in substantial consumer energy savings at a relatively low upfront cost.[1]

While the V2G technology scenario is future-focussed, the pricing arrangements we explore are based on current offerings in the market. We have also sought to accommodate the current regulatory constraints on tariff design.[2]

Methodology

enX has applied a range of technoeconomic and powerflow modelling methods to assess the impact of alternative network and retail tariff structures on V2G operation. We assume a future state with significant residential uptake of V2G (10% of households) at a specific network location (Ausgrid's Metford substation). Metford was selected as it has a high proportion of standalone dwellings with solar PV that may be early adopters of V2G.

Each V2G household was exposed to one of six network tariff and energy pricing scenarios (s1-s6) as listed in **ES Table 1**. Each scenario had one of three network pricing structures: *Unidirectional time-of-use (ToU), Bidirectional ToU or dynamic (critical peak)*, and one of two electricity retail pricing structures: *Origin Go ToU*[3], *Amber Electric spot pass-through*.

		Energy pricing scenarios	
		ToU Energy	Dynamic energy
Network tariff structure	Unidirectional ToU	**s1** Origin Go (residual) Ausgrid EA025	**s4** Amber Electric Ausgrid EA025
	Bidirectional ToU	**s2** Origin Go (residual) EA025 + EA029	**s5** Amber Electric EA025 + EA029
	Dynamic	**s3** Origin Go (residual) Dynamic network	**s6** Amber Electric Dynamic network

ES Table 1 – The six network and retail tariff combinations (scenarios) selected for modelling purposes

1 enX (2023) *V2X.au Summary Report Opportunities and Challenges for Bidirectional Charging in Australia*, p 3.

2 See *The network pricing objective and pricing principles*, p.19

3 The Origin Go retail product was considered relatively competitive. A residual retail cost was estimated by netting out Ausgrid's default ToU tariff (EA025).

Powerflow modelling was undertaken during a critical peak demand 'case study week' of 6-12 March 2023 and explored the operation of:

- 520 independently optimised vehicles, each with different plug-in profiles that on average conformed to a fleet-scale availability profile target.[4]
- One of four different user load profiles[5]
- A range of solar system sizes consistent with what currently exists in the Metford postcode area[6]
- Bidirectional dynamic operating envelopes (DOEs) operating across all scenarios[7]
- The six network tariff & energy pricing scenarios.

This resulted in 520 individual 'customer week' modelling runs for each tariff scenario (3120 optimisation runs in total). Results were then scaled to simulate the effect of 10% V2G penetration on the Metford substation during the case study week.

Cashflow modelling was conducted for the year October 2022 to September 2023 using a range of historical and synthetic data sources. The vehicle charge operation was assumed to be responsive to current and forecast electricity and network pricing as it would if operated by a modern home energy management system (HEMS). This optimisation was simulated using the Gridcog[8] modelling platform. This year was repeated 5 times with each customer year differing in terms of vehicle availability (plug-in behaviour) profiles. This was to reduce the random coincidence of vehicle availability with spot or network pricing events that could undermine the comparison of scenarios.

Results

V2G can substantially reduce substation critical peak demand.

ES Figure 1 shows the load profile for the Metford substation on Monday 6 March 2023. Peak demand for the year occurred at 6pm. The greatest reductions in peak demand (2.54 MW) were achieved under dynamic pricing (s3 & s6). This equates to 6.29% of substation firm capacity (41.6 MW). The combination of a bidirectional network support tariff and spot passthrough pricing (s5) delivered a reduction of 2.11 MW. Reductions resulted from EV battery discharges for self-consumption and export.

ToU retail pricing scenarios s1 & s2 were the worst performers; each promoted solar exports during the day (due to fixed feed-in tariffs) and EV battery discharge only for self-consumption. Spot pass-through arrangements encouraged significantly more charging during solar hours, and significant pre-charging ahead of anticipated evening peak events. Otherwise charging predominantly occurred overnight.

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4 See *Estimating vehicle availability*, p.45

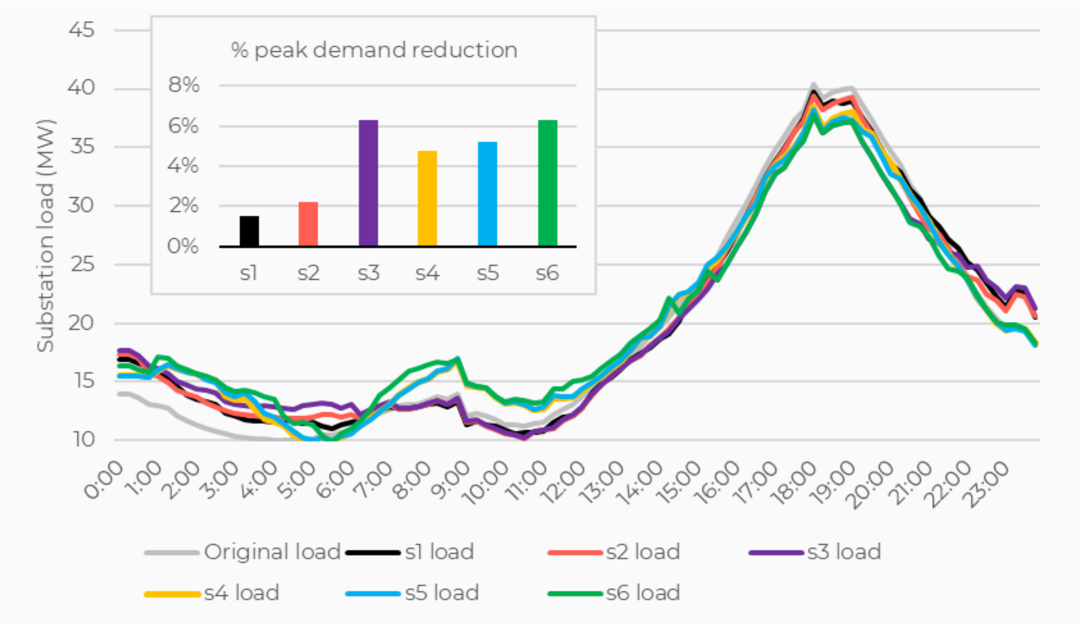
5 See *Customer load profiles,* p.42

6 See *Solar assumptions*, p.43

7 See *Use of Dynamic Operating Envelopes*, p.43

8 *www.gridcog.com*

ES Figure 1 – Change in substation load under each tariff scenario on 6 March 2023 assuming 10% residential V2G uptake. The 'original load' is actual substation load during the period.



The cost of critical peak demand reduction each scenario was lower that the estimated long run marginal cost (LRMC) of network expansion.

Annualised cashflows were modelled for scenario 2, 3, 5 & 6. The cost of load reduction was measured as annual net cash outflows from the network to participating customers (measured at the site level) for only variable pricing elements. A fixed daily supply charge was assumed to recover network residual costs[9]. This was compared to an estimated annualised LRMC for network expansion for Ausgrid of $42.80/kW.[10]

While all scenarios delivered reductions at a cost below LRMC, **ES Figure 2** shows that in s2 and s5, the network achieved net earnings over a year. This suggests that, with the assumptions in our model, Ausgrid's current bidirectional network support tariff would slightly over recover revenue from V2G customers. Overall, it is appropriate for customers to receive a net payment of variable costs where they are providing services that reduce the cost of the network for other customers.

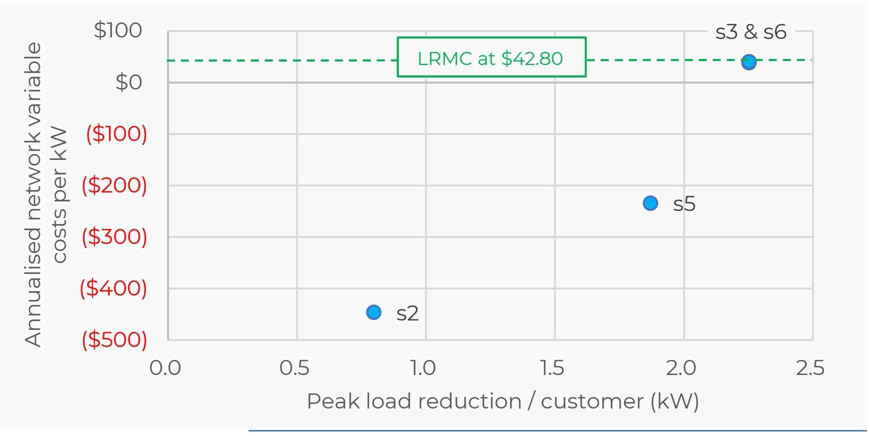
In s3 and s6, dynamic prices were set to ensure a high probability of demand reduction regardless of electricity spot market conditions (i.e., an 'insurance approach'). This addresses the situation where a local critical network peak may occur during very low wholesale market pricing causing spot exposed customers to charge (making the network peak worse). Our network peak price was set at $1.20/kWh to compensate for a countervailing minimum

[9] See *Residual cost setting*, (p.41). Note that the cost of operating a dynamic pricing scheme has not been considered and could be considered a fixed (residual) cost.

[10] Houston Kemp (2023) *Attachment 8.6: Long run marginal cost import methodology report Ausgrid's 2024-29 Regulatory Proposal*, p 1. LV LRMC in growing areas of the network

possible energy spot price of -$1.00/kWh.[11] An insurance approach has the effect of inflating critical peak pricing and costs to the network. We discuss policy and tariff design measures to address this.

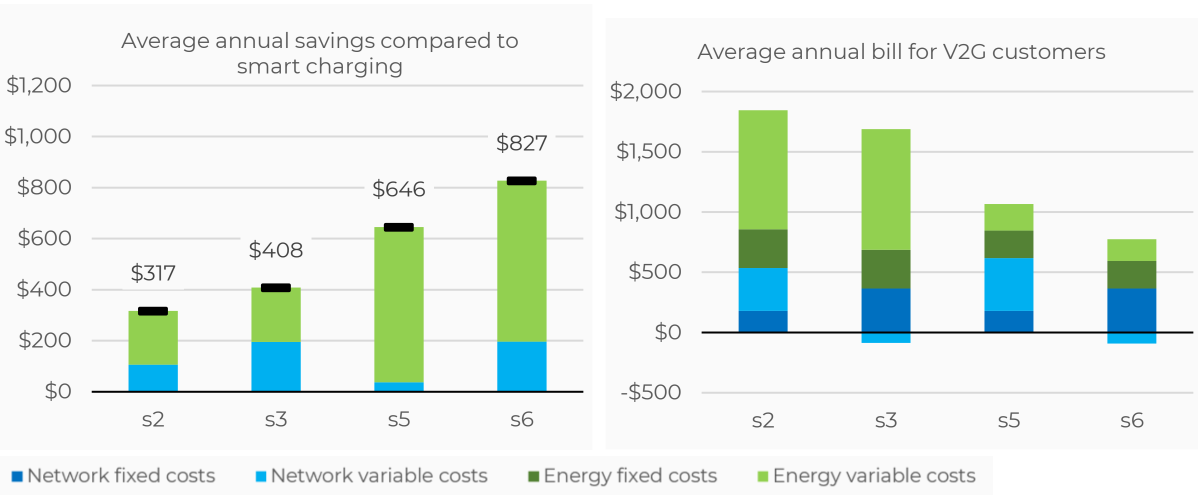
ES Figure 2 – Annualised network variable costs per customer vs. critical peak demand reduction achieved under each scenario. The vertical axis represents the price of demand reduction, and the horizontal axis represents the volume of demand reduction achieved during the critical peak.



V2G can substantially reduce customer energy bills.

V2G is more cost-beneficial than smart charging for all customers under all modelled scenarios with average savings per household of $550 per annum as shown in **ES Figure 3**. V2G customer bills come down with dynamic pricing and spot market exposure. In s3 and s6 customers receive a net payment for network variable costs. One small customer (not shown) was even able to pay for all household load, charge their EV and earn net revenue of $95 in a year.

ES Figure 3 – Average annual savings for V2G compared to smart charging and breakdown of average V2G customer energy bills under each scenario



[11] See *Ensuring a firm response, market floor price consideration*, p.40

Spot pass-through customers are best off on dynamic network pricing.

Outside of peak times, dynamic network charges are zero. This reduces transaction costs associated with electricity market participation decreasing energy bills on average by $41 per annum.

Key finding of this study include:

1) **Dynamic tariffs are the most grid-beneficial arrangement for V2G, delivering the highest rate of peak demand mitigation.** Grid benefits were highest under dynamic tariff and spot price passthrough arrangements which, combined, provided incentives for exports during critical peak times and lowest cost re- and pre-charging.

2) **Dynamic network tariffs delivered the best result for customers.** This is because customers were specifically rewarded for reducing network peaks rather than their incentives being smeared, as they are under ToU tariff arrangements. Overall, V2G customers can be net providers of grid support services, and get paid for it.

3) **Setting dynamic pricing against the market floor price (MFP) may be necessary to ensure a more reliable and maximal V2G response.** The implications of the MFP for DER operation and local network stability, should be more fully considered by the AEMC Reliability Panel. Dynamic tariff rates can be reduced by settling on a contract-for-difference basis, that ensure customers receive guaranteed net revenue during MFP events.

4) **Bidirectional ToU network tariffs are unlikely to support efficient outcomes from V2G operation** as they suffer from the same intractable limitation as all ToU prices; in order to offer sufficient incentives to support V2G battery discharge during critical peaks, they must overcompensate discharges throughout the year (or season), so they default to under-compensation.

5) **Spot passthrough retail contracts can greatly reduce costs for EV owners with smart charging and V2G.** Customers with flexible, and especially bidirectional resources, can move their load and generation around to take advantage of dynamic spot market conditions., insulating themselves from price risk exposures.

6) **Dynamic network tariffs amplify the benefits of spot passthrough arrangements** by reducing transaction costs outside of critical peak periods. This allows for freer trade in the spot market and greater opportunities for spot market arbitrage.

7) **V2G operation outcomes are somewhat influenced by household load characteristics.** Field trials are needed to validate our modelling results and to determine, more precisely, the customer and DER technology types that can most benefit under spot passthrough and dynamic network tariff arrangements.

8) **V2G will be a financially attractive proposition to many EV drivers.** Compared to smart charging, V2G contributed additional annual savings of between $118 and $960 across the users and incentive arrangement explored in this study. Cost-subsidies can be avoided by ensuring network pricing remains cost-reflective such that net benefits from V2G spill over to all electricity customers.

9) **Vehicle availability matters.** Some of the largest V2G fleet discharges occurred outside of critical peak times. One of the reasons for this was simply because there many more vehicles plugged in and available to respond to pricing incentives. Our vehicle availability model allows this effect to be explored at different system levels.

10) **Secondary peaks can undermine the network value of V2G at high penetrations.** Secondary peaks are those that have not been forecast by the network operator or factored into dynamic pricing. Further work is needed to explore the circumstances under which secondary peaks could occur, and how they could be effectively mitigated. Outcomes from field trials will be essential in determining instantaneous and intertemporal demand elasticity and to inform models that networks can use to support the use of more targeted incentives without undermining broader network operation.

11) **Network tariff reform needs to be accelerated and become more 'technology aware'.** The NEM is moving to a new regulatory environment where tariff decisions can be assessed against not only the pricing principles but their ability to support jurisdictional emissions reduction targets. Innovative approaches to tariff design are needed to unlock the value of DER and greater effort is required to coordinate learning between networks to support the diffusion of leading approaches. Greater coordination by network businesses, and more rapid deployment of tariff innovations can bring forward the technology and commercial innovation required to achieve Australia's emission reduction objectives.

Contents

1. The purpose and scope this study

1.1. Introduction

Our previous study, *V2X.au Summary Report Opportunities and Challenges for Bidirectional Charging in Australia*[12], found that network tariffs can make or break V2G and that network businesses should collaborate to develop more cost-reflective tariffs to signal national coherence to international supply chain stakeholders. We based this on customer-level revenue modelling of smart charging, bidirectional charging, and international supply chain stakeholder consultations.

Overall, Australia's approach to network tariffs can be characterised as fragmented (with different approaches in different network areas) and experimental (networks are trialling several innovative pricing approaches). The most preferable current pricing arrangements for *participating customers* are bidirectional network support tariffs such as those being pursued by Ausgrid, SAPN and Essential Energy. Dynamic pricing arrangements, such as those being trialled by Ausgrid under Project Edith, are internationally leading and have the potential to support more efficient operational and investment outcomes for customers and networks but were not considered in the V2X.au study.

This study digs deeper into the potential role of network tariffs in shaping smart and bidirectional charging. It examines the power flow and revenue implications for customers and network businesses and seeks to identify the strengths and weaknesses of different tariff arrangements in promoting efficient outcomes for all electricity system users.

This study does not assume that tariffs should be made available for only specific classes of technology. The focus on smart charging and V2G should be viewed as a case study that is potentially transferred to other forms of distributed energy resources (DER). However, the expected uptake of EVs, and their flexible and bidirectional charging characteristics, creates an opportunity that warrants specific focus.

EVs and chargers capable of bidirectional charging are expected to become more broadly available in the Australian market from 2024. They will be located on distribution networks, electrically adjacent to customer load and therefore be able to access a wide range of revenue streams including tariffs designed to support network operation under maximum and minimum demand conditions.

1.2. Progress towards more efficient tariff structures

Electricity networks are platforms across which electricity is transported from generators to consumers and the way consumers use and produce electricity has an impact on the costs of this platform service. This is most pronounced where increasing *peak demand* requires networks to invest in new (or augment existing) network assets. Increasingly, Distribution Network Service Providers (DNSPs) are also considering costs associated with hosting increasing levels of distributed generation. This can require investments to manage low or

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[12] enX (2023) *V2X.au Summary Report Opportunities and Challenges for Bidirectional Charging in Australia*, p 3.

more variable demand and even reverse power flows. Costs associated with network upgrades are nearly always passed through to consumers.

An ‘efficient’ network tariff encourages efficient use of network assets, typically reflected in lower demand peaks and higher troughs. A flatter load profile mitigates the need for network capital expenditure which reduces costs for all network users. An efficient tariff also encourages consumers to use electricity only when they value it more than the cost of delivering it.

Network tariffs should also result in ‘equitable’ recovery of historical network capital outlays. Equity is associated with the idea that consumers with low peak demand should not have to cross-subsidise other users that contribute to higher peaks. This means ensuring that customer behaviour, which contributes to lower network costs, is appropriately rewarded. The concept of equitable cost recovery can be applied to historical and forward-looking investments. However, forward-looking investments are generally more heavily weighted when determining variable network prices as they can often be avoided, or delayed, when consumers respond to price signals.

EVs result in a step change in electricity demand elasticity.

The ability and willingness of customers to vary their electricity usage in response to price signals is called *price elasticity*. Historically, many customers have had limited ability to vary their demand in response to electricity pricing and so price elasticity of electricity demand has traditionally considered to be low. Electricity is also generally defined an essential service and a customer’s ability to afford electricity when they need it, such as for winter heating or summer cooling, is a key consideration.

The level of demand elasticity in the electricity system is expected to grow substantially over the coming decade with the uptake of electric vehicles (EVs). Like charging for any other kind of energy storage, EV charging is inherently flexible and there is considerable scope to shape EV charging profiles to enhance network utilisation while still ensuring the vehicles can fulfill their primary purpose: moving people and things around. Flexible EV charging can reduce costs for network owners and all electricity customers (reflected in low electricity network charges). This can be enabled by digital control technologies that allow for smart automation of the charging process (i.e., ‘smart charging’), designed to ensure that the needs of EV owners are met, and costs are kept to a minimum.

1.3. Tariffs support ‘distributed optimisation’.

Network tariffs are a way to signal to smart EV chargers when it is the best time to charge to make use of available network capacity. This price signalling approach has some advantages over network businesses having direct control over charging. It allows customers flexibility to charge their EVs at peak times, if it is worth it for them, or instead reduce other flexible loads, such as smart water heating, which is equally valuable to the grid on a per kW basis. Overall, price signalling supports *distributed optimisation* where customers (and their agents) can determine when it is best for them to charge their EV, taking account of their individual needs and interests and factors such as network, retail, or wholesale market price signals.

From an economic perspective, distributed optimisation promotes *allocative efficiency,* which, in the context of EV smart charging, means EVs are charged at the best possible time and rate for both the drivers and the grid. Allocative efficiency is a term that economists use to describe how well the resources in an economy are used to produce goods and services that people want, such as supplying the electricity to charge a car. Allocative efficiency is achieved when every good or service is made and sold at the right quantity and price, so that both the producers and the consumers are satisfied with their sales and purchases.

An electricity price is allocatively efficient if it is equal to its *marginal cost*, which is the cost of producing one more unit of it. If the price is equal to the marginal cost, then allocative efficiency is more likely to be achieved, because the last unit produced provides the same benefit to the consumers as it costs to the producers. The same principle applies to networks service provision: it is important that networks do not incur costs for providing a service that exceeds consumers' willingness to pay for it.

A key focus of this study is exploring how the marginal cost of electricity supply can be signalled to encourage efficient use of electricity networks, and how that can promote efficient EV charging outcomes for both the owners and the grid.

Vehicle-to-grid (V2G) signals a major change for distribution networks.

In mid-2023, ARENA published our *V2X.au Summary Report – Opportunities and Challenges for Bidirectional Charging in Australia*.[13] It found that, by the early 2030s, most of the NEM's energy storage capacity is expected to be located on distribution networks in customer-owned distributed energy resources (DER) such as batteries, and especially EVs. Unlike historical types of customer load, DER is designed to be sensitive to network pricing arrangements (i.e., it they have high demand elasticity). This creates new opportunities to promote more efficient gid investment outcomes, reducing costs for all electricity customers, that were not previously available.

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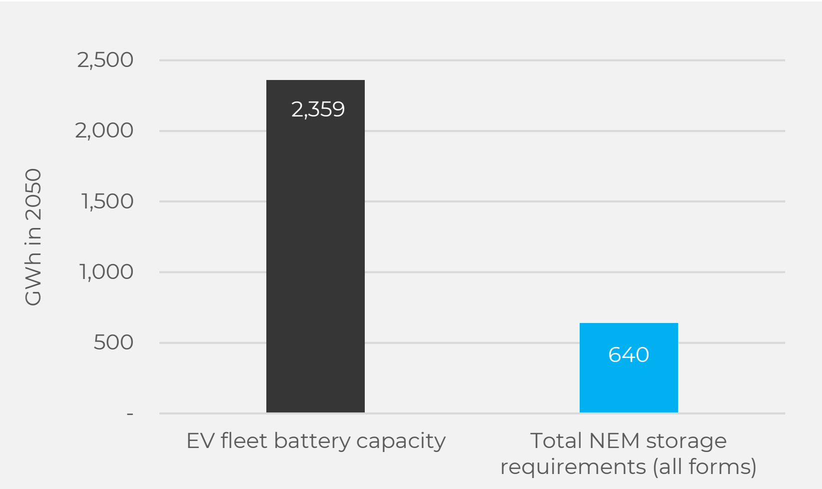
[13] enX (2023) *V2X.au Summary Report Opportunities and Challenges for Bidirectional Charging in Australia*, p 3.

Figure 1: Estimated gross energy storage capacities in the NEM in 2050 (GWh).[14]



Vehicle-to-grid (V2G) is technology that allows not only for EV charging to be shifted to reduce network peaks, but also to support the grid when it is under pressure, by exporting power from the EV to meet customer load and/or export to the grid.

Distributed optimisation is the key to unlocking this resource. The energy in an EV battery has value to the EV owner. It can be used to power the car or in the electricity market where it can be used like a traditional peaking generator, exporting power, and earning revenue during high pricing periods. Price signals allow EV owners to choose their charge and discharge behaviour in way that maximises the return on their investment while producing beneficial outcomes more widely across the electricity system and the economy.

The *V2X Summary Report* found that Australia's EV fleet will be the largest and lowest-cost potential storage resource in our energy transition—nearly four times total NEM storage requirements by 2050. This study found that flexible bidirectional charging from only 10% of this capacity could provide 37% of total NEM storage needs, offsetting around $94 billion of large-scale battery storage investment (at current battery prices). By the early 2030's, EV fleet battery capacity is likely to surpass all other forms of storage in the NEM, including Snowy 2.0. Flexible and bidirectional EV charging therefore represents one of the largest potential enablers of Australia's energy transition to renewables and electrification. As virtually all of this will be located on distribution networks, close to customer load, the magnitude of the opportunity for network businesses to use distributed optimisation techniques to achieve efficient network utilisation, should not be underestimated.

Another important finding of our *V2X Summary Report* was that V2G customers are nearly always better off when exposed to electricity wholesale spot market prices, compared with flat or ToU retail pricing products. Bidirectional charging can take advantage of even short-duration price movements in electricity wholesale market and this can greatly reduce the cost of charging and enable lucrative returns by exporting during peak pricing periods. However, another enX study for AEMO found high levels of price responsiveness also creates the risk of

[14] Ibid.

highly dynamic and coincident demand, which needs to be managed to preserve the stability of voltage and frequency within regulated limits.[15]

The *V2X Summary Report* found that, under Ausgrid's EA960 'bidirectional network support tariff', charging a V2G-enabled EV over 10 years can earn a customer more money than it costs to charge their vehicle while helping to reduce electricity peak demand. While this great for EV customers, there is a need to understand cashflows at a more granular level to assess the true value of V2G to networks in reducing peak demand, and whether different incentive structures could produce more efficient and effective outcomes.

Bidirectional network support tariffs provide incentives for V2G customers to export based on a time-of-use (ToU) schedule. These ToU pricing arrangements are typically annualised or seasonal, meaning they provide incentives for EVs to export during *likely* peak demand periods (e.g., 5pm to 10pm in summer) including on such days when the grid is not under pressure. This means that most of the time, ToU tariffs over or under incentivise desirable behaviours: customers get rewarded for behaviours that have no economic value and the pool of funds available to networks to incentivise exports when peaks occur is reduced.

Most consumers want to get rewarded for the services they provide. One recent empirical study found that even small savings, like $10 (USD) per month were very effective in shifting EV charging behaviours. However, 'moral suasion nudges' were ineffective, and no habit formation was observed once the saving incentive was removed.[16]

Networks are in various stages of setting tariff directions for the next 5 years.

Each 5-year regulatory period, DNSPs are required to submit a tariff structure statement (TSS) to the Australian Energy Regulator (AER) for approval. The TSS sets out the DNSP's proposed strategies for network cost recovery, including through distribution use-of-system (DUoS) charges (tariffs), tariff classes, structures, and assignment policies. The TSS must be informed by the views of its stakeholders and customer impact analysis. The DNSP's annual pricing proposal is assessed by the AER against the NER.

The AER expects DNSPs to gradually make their tariffs more 'cost reflective' but must do so in accordance with the pricing principles in the Rules.[17]

Tariffs can be used to both mitigate negative network impacts (reducing demand) and incentivise customers supporting the network at times of peak demand (by providing credits for exports at these times). Economic theory generally suggests that best practice tariffs would be bidirectional, and pricing would be reflective of different levels of congestion at different times of the day/year. For this reason, tariffs are generally evolving to become more complex and dynamic, with some of the more complex tariffs more suited to promoting automated responses rather customer behaviour change.

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[15] enX (2023) *EV technical standards for grid operation – Insights for the NEM*

[16] Other studies exploring EV price responsiveness include Megan R. Bailey, David P. Brown, Blake C. Shaffer & Frank A. Wolak (2023) *Show me the money! Incentives and nudges to shift electric vehicle charging timing*, p 3.

[17] AER (accessed 19/09/23) *Network Tariff Reform*

New tariff structures for batteries and EVs are being developed and trialled in different network areas.

Network tariffs must be appealing to retailers and customers

Most customers are not exposed to network tariffs directly and electricity retailers decide whether to pass them through in a competitive market context. This means that in additional to being cost-reflective, tariffs also need to be appealing to retail customers to have an impact (other than when a customer is facing network tariffs directly such as with Amber Electric.[18])

Our V2X.au Report modelling indicated that network tariffs can make or break the customer business case for V2G and inconsistencies between network businesses (alongside a lack of national policy direction) discourage technology providers entering the Australian market. Accordingly, enX recommended that DNSPs collaborate to develop more V2G-supportive tariffs to signal national coherence to international supply chain stakeholders. While the AER assesses each network individually, it does not have an explicit mandate to promote national consistency, even if it is in *the long-term interests of* consumers.[19]

1.4. Marginal cost as the economic basis for setting network prices

One goal of economic regulation of monopolies is to try and replicate the efficient pricing outcomes produced by a competitive market. In competitive markets, microeconomic principles suggest that prices should be equal to marginal cost of supply (with some qualifications).[20]

The marginal cost of supplying a good or service refers to the change in total costs of producing one more unit of a good or service. Economic theory suggests that when prices equal marginal cost, consumption decisions are efficient, as consumers compare the benefits of an additional unit of consumption with the costs of supplying an additional unit. This promotes allocative efficiency as resources tend to flow to goods and services most valued by consumers.[21]

The marginal cost of providing an electricity distribution service varies depending on the chosen time horizon. Short run marginal cost (SRMC) is the incremental cost of meeting an incremental change in demand on the network (as built) in operational timeframes. Long run marginal cost refers to the change in cost associated with building the network to meet peak (or minimum) demand over planning timeframes.

What is SRMC?

For network businesses, SRMC considerations have traditionally been less prominent than LRMC as there are few options available to networks to ‘procure’ increased network capacity

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[18] Amber Electric (accessed 19/09/23) *Tariffs Explained*

[19] AEMC (accessed 27/11/2023) *National Energy Objectives*

[20] See for example: Green (2020, accessed 19/09/23) *Network pricing - Part 1*

[21] AEMC (2014) *Distribution Network Pricing Arrangements, Rule Determination*, p 119.

(and thereby increase their costs) in real time. The SRMC of electricity networks is associated with:

- Electrical losses on the network, which generally increase as the network becomes more heavily loaded.[22]
- Managing network congestion in the network:
    - The activation of network support contracts, for example for local generators that are switched on to support the grid during peak demand peaks. These costs are funded by network operational revenue allowances and ultimately recovered from customers.
    - The cost to consumers when their supply is restricted or turned off to manage emergency situations.[23]

Wholesale markets in the NEM accounts for SRMC of electrical losses via *distribution loss factors* and the cost of losses is passed through to customers via electricity retailers.[24]

SRMCs for the management of network congestion is generally near-zero at times and locations where there are no network constraints (most of the time) and very high at times and locations where the network faces critical constraints or outages.[25]

What is LRMC?

Conversely, LRMCs are incurred over a longer period where network capacity can be increased through strategic investments. They include the cost of expanding network capacity to meet an expected peak demand growth, or to mitigate expected risks associated with falling minimum demand. These investments are based on forecasts of how power flows on key network assets might change over time. Due to economies of scale, additional network capacity is typically added in large amounts, rather than in small increments. So, even though LRMC may be framed as a cost *per kW* of servicing a growing (or falling) load, the investments in new capacity may individually deliver tens or hundreds of MW at a time. These investments may also take several years to deliver making them slow, large, and lumpy and to be avoided, if possible.

Ausgrid has conducted an LRMC analysis is based on 16 case studies of low voltage distributors, sampled to produce a range of different distributor types, such as regional and metropolitan locations, and areas with high or low DER penetration. This modelling showed a small positive LRMC associated with increased solar generation, meaning that over the long

[22] One study found that, as the EV penetration level increases from a base value to 100%, the daily energy losses rise from 0.53% to 0.74%. IEEE (2023) Wu, Y, Syed A. Haque, M, Kauschke T. *Impact of Electric Vehicle Charging Demand on a Distribution Network in South Australia*, p 4.

[23] The value of lost load (VoLL) is a term that describes how much money people would be willing to pay to avoid losing electricity for a certain period. It is a way of measuring how much electricity is worth to different customers, such as households, businesses, and industries.

[24] See for example: AEMO (2023) *Distribution loss factors for the 2023/24 financial year*

[25] AEMC (2014) *Distribution Network Pricing Arrangements, Rule Determination*, p 121.

run, a kilowatt of investment in solar capacity triggers an associated positive network upgrade cost.[26]

Ausgrid notes that its export pricing structure includes charges and rewards. Customers who respond to these price signals (e.g. by installing a battery or adopting behavioural changes to shift their consumption profile) will have the opportunity to reduce their exposure to export charges and increase the opportunity to receive export rewards. Ausgrid expects to recover a greater proportion of export LRMCs from export tariffs into the future.[27]

The accuracy of load forecasts and the timing of investments can have a material bearing on final cost outcomes and so it is important to understand the tariffs and other measures that can reduce or delay the need for network investment. For example, Ausgrid predicts increased load through EV uptake. If not integrated effectively, EVs could increase load at peak times or create new peak loads in part of the network (such as car parks), causing network augmentation requirements and a higher cost burden for customers.[28]

LRMC pricing includes in the incremental increase in cost of bringing an investment forward, rather than delaying it. In a circumstance where it is a matter of when, not if, an investment should occur, LRMC represents the difference in the net present value (NPV) of the investment happening sooner or later.[29] Furthermore, investment costs can vary substantially between different types of capacity investment in different locations. Overall, LRMC will generally be higher in parts of the network where peak demand is growing fastest.

Distribution networks are required to use long run marginal costs to set network prices. As more DER is integrated into the grid, and the opportunity to 'procure' services increases, this may change.

What are 'residual costs'?

Costs that are not forward looking or responsive to changes in energy demand are referred to as *residual costs*.

These are the costs remaining after recovering LRMC (and SRMC) and are generally the costs associated with historical capital investments, including regulated rates of return, and fixed operating overheads. Residual costs can be a very high proportion of total costs. One estimate suggests that applying a pure LRMC charge would only recover 10 to 30 percent of the total efficient network costs.[30] However, this is likely to be highly dependent on local factors including forecast load growth compared to the rated capacity of a local network asset. Current forecast drivers of load growth, including EV charging and electrification, will result in

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[26] Ausgrid (2023) Tariff Structure Statement Compliance Document *2024-29*, p 12

[27] Ibid, pp 39- 41.

[28] See for example: AER (2023) *Attachment 5.7 of Ausgrid's 2024-29 Regulatory Proposal* p 8.

[29] Ibid.

30 Argyle Consulting and Endgame Economics (2022) *Network tariffs for the distributed energy future Final paper for the Australian Energy Regulator*, June 2022, p 25.

residual costs being a lower proportion of total costs *if* that results in the need for additional network capital expenditure.

Ausgrid has argued that including residual costs in variable export tariffs can distort customer decisions. In its recent bidirectional network support tariff trial, it found it made its trial tariff too lucrative for customers investing in batteries and drove additional cycling of batteries that was not justifiable based on network need. This has informed its decision to base export charges and rewards only on the LRMC of exports on its network. [31]

Both SRMC and LRMC are generally bidirectional and symmetrical in nature. From a network's perspective, 1 kW of generation in a network location can offset the costs associated with 1 kW of load occurring at the same time. It therefore makes sense that whatever is charged to the load, should be paid to generator (at the same location in the network). Overall, this would result in zero net payments for zero net load (i.e., as though there was no load to begin with).

This principle applies over all timeframes and for most LRMC and SRMC expenditure items.

1.5. The take-up of cost-reflective tariffs in the NEM

The term 'cost-reflective' is commonly used to refer to network tariffs that have variable charges that reflect a network's marginal costs. Since 2014, distribution network businesses have been required to offer cost-reflective tariffs across all customer classes. These can be assigned to customers on an opt-in or opt out basis, where the customer has appropriate digital interval metering. The intention of these reforms was to provide consumers with greater choice and control of their energy bills and to reduce the costs of operating the network for all consumers by encouraging more efficient energy usage behaviour.[32]

The AER tracks progress in tariff reform by assessing how many residential customers have their retailer exposed to a cost-reflective network tariff.[33] The **Figure 3** below shows the progress of residential customer assignment to cost reflective tariffs. On 30 June 2022 only 25.73% were on a cost reflective tariff, an increase of approximately 9% from the previous year.

The reasons for this vary among DNSPs but are influenced by deployment of advanced metering technology, tariff assignment policies, customer engagement, and jurisdictional requirements. Tariff reform involves replacing flat tariffs with Time of Use (TOU) energy charges and TOU-demand tariffs, allowing for more accurate attribution of network costs.[34]

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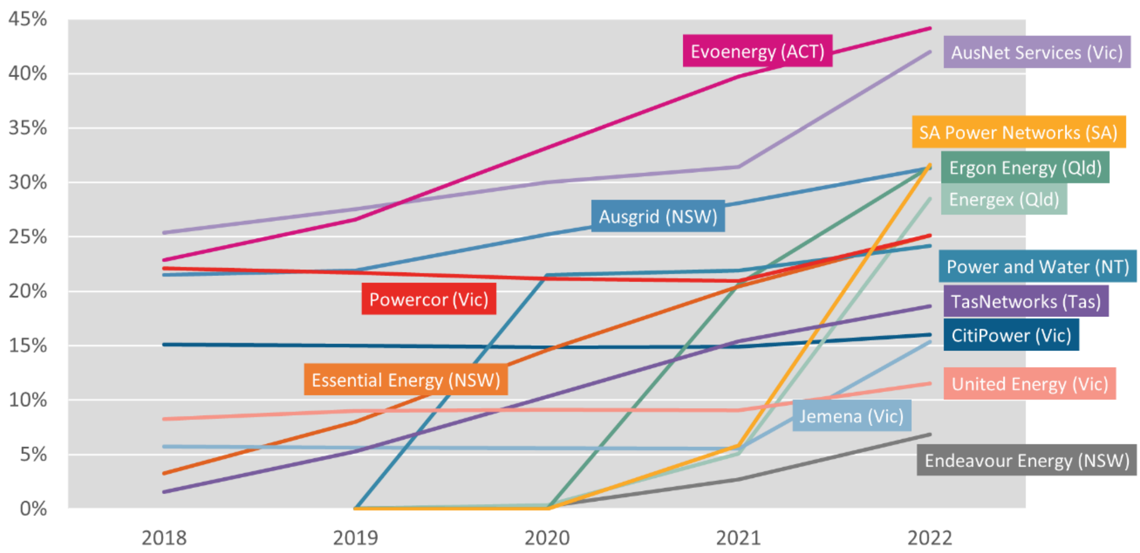
31 Ausgrid (2023) *2023-24 sub-threshold tariff notification*, p 7

32 AEMC (2014) *National Electricity Amendment (Distribution Network Pricing Arrangements) Rule 2014*

33 AER (accessed 19/09/23) *Network Tariff Reform*

34 Argyle Consulting and Endgame Economics (2022) *Network tariffs for the distributed energy future Final paper for the Australian Energy Regulator*, June 2022, p 12.

Figure 2 – Proportion of residential customer on cost-reflective tariffs (2018-2022)[35]



Retailers ultimately determine how to pass on the network tariff signal to the end use customer and this is discussed in section 2.7 on page 27.

35 AER (accessed 19/09/23) *Network Tariff Reform*

2. How distribution networks tariffs are regulated

2.1. Networks as natural monopolies

Electricity networks are natural monopolies because they provide a service that is most efficiently delivered by a single supplier in each region. This is because the cost of building and maintaining the infrastructure of poles, wires, substations, and transformers is very high, and it would be wasteful and impractical to have multiple competing networks in the same area.

Monopoly characteristics include:

- Customers cannot take or leave the services they provide since they are essential to everyone's day-to-day activities. Most of these customers have very limited countervailing bargaining power.
- High fixed costs to provide safe and reliable electricity supply.
- Scarcity of easements needed by DNSPs and opposition from homeowners and local councils to network duplication.
- The need for the system to act as a coherent network, with appropriate power quality controls.[36]

Because of their monopoly position, electricity networks are regulated by the government to prevent them from abusing their market power, charging excessive prices, or providing poor quality service to the consumers. The theory and evidence about the behaviour of natural monopolies suggest that, without strong regulation, networks could be expected to set excessively high prices and potentially provide low-quality services.[37]

While the growth of customer-owned DER may provide some counter-veiling power, a DER customer still relies on the network for supply at times when the solar PV or battery (including V2G) is not able to generate all the electricity consumption desired. The same customer may also obtain value from exporting excess power, earning revenue by offsetting costs associated with other customer’s electricity demand.. Whether or not a customer has DER or not is not considered to mitigate the need to regulate how costs are recovered.

2.2. How networks cost recovery is regulated

There are essentially two main approaches to regulating cost recovery by monopolies regulation. The first is *rate of return regulation*. This is where the regulator specifies the return on capital that a firm is allowed to recover, regardless of its performance. The other is *incentive regulation*. This is the form more commonly used by regulators, as it limits natural monopolies’ ability to exercise market power while maintaining some incentives for businesses to minimise costs and innovate.[38]

36 Productivity Commission (2013), *Electricity Network Regulatory Frameworks, Report No. 62,* Canberra, p 122

37 Ibid, p 121.

38 Ibid, p 187

Incentive regulation is applied to networks in the National Electricity Market (NEM) using the *building block* approach. This is the procedure for determining the total revenue allowance for a five-year regulatory control period. This is 'built up' based on the network's capital assets, capital and operating expenditures, depreciation, tax, the *weighted average cost of capital* (WACC), and incentive schemes. Networks that spend less than forecast are allowed to keep a proportion of the remainder, which they share with customers in the form of lower prices.

Revenue cap or price cap

Networks recover their maximum revenue allowances from customers through control mechanisms that are usually a form of *weighted average price cap* or a *revenue cap*.

A **revenue cap** control sets the maximum allowable revenue for a regulatory control period. The network forecasts demand and sets prices to achieve expected revenue below or equal to the cap.[39] Under a **weighted average price cap** (WAPC), the regulator sets average price increases at the start of each five-year regulatory control period, allowing revenue variation with demand. Networks can adjust prices, provided the average 'basket' of tariffs doesn't exceed the limit.[40]

A revenue cap is generally associated with stable pricing structures to ensure revenue predictability. This may mean networks are less interested in using tariffs (including V2G) to drive efficient behaviour and better network utilisation as its revenues are guaranteed. There is some evidence of this in the lack of customers on cost reflective tariffs.

Conversely, under a WAPC, where prices are linked to demand, it may potentially provide a stronger incentive for DNSPs to design tariffs that better align with the value of specific grid support services like V2G. A price cap supports greater demand and throughput on the network. Relative to a revenue cap, it is likely to be more compatible with electrification ambitions, which seek to move customers from fossil gas to electricity generated by renewable resources.

DNSPs currently operate under a revenue cap for the provision of standard control services. Most distribution services are classified as standard control services because they are central to electricity supply and relied on by most (if not all) customers.[41] This is unlikely to change over the next two regulatory control periods, which apply to NSW, ACT, NT, and TAS DNSPs. However, the AER should consider the merits of a WAPC in the future as more V2G and price responsive assets become 'the norm' and electrification of the NEM accelerates.

Alternative control services are subject to price caps. These services are provided to specific customers for a discrete fee offered as a 'user pays' charge.[42] There are several examples:

- Network-related property services such as conveyancing enquiry services.

39 ENA (accessed 19/09/23). *Put a cap on it – but what sort of cap?* | Energy Networks Australia

40 Ibid.

41 AER (2022) *Framework and approach Ausgrid, Endeavour Energy and Essential Energy (New South Wales) Regulatory control period commencing 1 July 2024*, p 4.

42 ibid, p 11.

- Network safety services, such as the provision of traffic control services by the DNSP or a third party where required.
- Provision of training to third parties for network-related access.
- Authentication of accredited service providers.
- Public lighting and streetlighting construction, operation, and maintenance.

2.3. Tariff classes

The NER requires DNSPs to assign customers to tariff classes based on one of more factors:

- nature and extent of usage
- type of network connection
- metering
- retail customers with a similar connection and distribution service usage profile should be treated on an equal basis (except standalone power systems).[43]

The purpose of tariff classes is to avoid cross subsidies between customers that cause different network costs. DNSPs have some flexibility how they allocate, for example by voltage, customer type or capacity.[44] For example, Ausgrid and other networks base it on the attributes of the customers connection. Low voltage customers have a 230V or 400V connection, as measured at the metering point. This includes residential, small business and light industrial customers. High voltage customers are industrial customers on the 11kV network and sub transmission customers are 33kV and above.[45]

As more price responsive flexible DER assets connect to the grid, it will change the nature and extent of usage. Accordingly, DNSPs may increasingly segment these in tariff classes for the purposes of setting cost reflective prices. It may do this to mitigate negative network impacts and incentivise customers supporting the network at times of peak demand. V2G customers could be a member of this class.

2.4. The network pricing objective and pricing principles

The rules for designing network tariffs are set out in *Chapter 6, Part I* of *the National Electricity Rules (NER).*[46] This requires networks to comply with both a *Network Pricing Objective* and *Pricing Principles.*

The *Network Pricing Objective* specifies that 'the tariffs that a Distribution Network Service Provider charges in respect of its provision of direct control services to a retail customer should

43 NER clause 16.8.4.

44 AEMC (2014) *Distribution Network Pricing Arrangements, Rule Determination,* 27 November 2014, Sydney, pp 178-180.

45 Ausgrid (2023) *Ausgrid's Tariff Structure Statement Compliance Document 2024-29,* p 5.

46 NER Part 6 Part I: Distribution Pricing Rules - AEMC Energy Rules.

reflect the Distribution Network Service Provider's efficient costs of providing those services to the retail customer.'[47]

The *Pricing Principles* provide further guidance on how networks should determine pricing for customer use of the network.[48] A summary of the Pricing Principles and key considerations is provided in Table 1.

Table 1 – NER network pricing principles

Pricing principle	Summary
1. Tariff classes must be between standalone and avoidable costs (NER 6.18.5(e)).	Standalone cost is the cost of providing electricity to a group of customers (tariff class) as if they were the only ones using the network. Avoidable cost is the cost that would be saved if that tariff class stopped using the network. This requirement combined with tariff class assignment principles, seeks to minimise cross subsidies between different classes of customers.
2. Tariff must be based on LRMC, and methodology must be appropriate (NER 6.18.5(f)).	DNSPs must consider how to calculate and apply LRMC for network tariffs including: • The cost and benefits of the method used to calculate and implement LRMC • How much more money a DNSP needs to spend to meet the demand of customers on a tariff at times when the network under stress • Where the customers assigned to a tariff are located and how much the cost of supplying electricity changes depending on the location.
3. Revenue from each tariff must recover total efficient cost and minimise distortion (NER 6.18.5(g)).	The DNSP forecasts quantities for all the network tariffs and tariff components. The total revenue expected to be recovered from each tariff must reflect the DNSP's total efficient costs. Where there is a revenue shortfall, the DNSPs can adjust tariffs but only to extent necessary to minimise distortions to the LRMC price signal. The shortfall is generally because the LRMC price signal it is not sufficient to cover residual costs. The most common, and potentially least distortionary approach is to use fixed charges, such as daily supply charges.[49]
4. DNSPs must consider the impact on retail customers of changes in tariffs from the previous regulatory year (NER 6.18.5(h))	Following an impact assessment on retailer customers, the DNSP can vary tariffs in accordance with the pricing principles listed above. However, it should consider whether: • a transition period is necessary • the retail customer can choose its retail tariff • the retail customer can mitigate the impact of changes in tariffs through their decisions about their usage of the service
5. Tariff structures need to be understood and impacts on retail customers considered (NER 6.18.5(i)).	The structure of each tariff must be reasonably capable of being understood by retail customers including how their usage decisions or controls may affect the price paid. Alternatively, it must be capable of being incorporated by *Retailers* or *Market Small Generation Aggregators* (now called *Small Resource Aggregators*).

47 NER clause 6.18.5 (a).

48 NER clause 6.18.5 (b).

49 Green (accessed 19/09/23) *Network pricing - Part 2*

Additional principles	Summary
NER, clause 6.18.4(a)(2) principles governing tariff class (re)assignment	DNSPs are to treat customers with the same connection and usage profile on an equal basis. Therefore, tariffs are required to be technologically neutral and simply signal the costs and benefits from customer use of the network. For example, the AER has stated that it does not support the introduction of discounted tariffs for EV owners or EV charge point operators.[50]
General principle about compliance NER, clause 6.18.5(j).	The NER contains a general pricing principle that tariffs must be compliant with the Rules and any applicable regulatory instruments, such as jurisdictional requirements.
Side constraints on tariffs for standard control services (NER, clause 6.8.6).	The NER requires the DNSP to impose side constraints that limit how much DUOS revenue can be recovered from a tariff class relative to the revenue recovered from the same tariff class in the preceding year. In practice, the imposition of side constraint limits prevents any large rebalancing of revenue recovery between tariff classes, and price shocks for individual customer classes, during the regulatory control period. Usually, the side constraint limits the rebalancing of revenue recovery between tariff classes to 2% above the allowed annual revenue path.[51]
Export tariffs must have a basic export level (NER, clause 11.141.12)	A retail customer must not pay extra to export to the network up to a basic level for the next two regulatory periods. The basic export level should be set regarding intrinsic hosting capacity and expected demand for export capacity (NER clause, 11.141.13(b)). This limits the ability for DNSPs to offer a symmetrical LRMC charge for consumption and exports below the basic export level until 2034. Ausgrid estimates that this requirement removes the price signal from around 70% of exports that drive its future network costs.[52]

2.5. LRMC pricing methodologies

Pricing principle 2 requires that distribution network tariffs are based on LRMC, but the NER does not prescribe a methodology to do this. This is because that there is not a universally agreed method for translating LRMC into network pricing and different methods have benefits and detriments depending on the DNSP's circumstances.[53]

Most DNSPs use the average incremental cost (AIC) method to calculate LRMC. This methodology estimates LRMC by calculating capital, operations, and maintenance expenditure required to meet projected demand growth over 10 years. It then calculates the present value of the expenditure required and divides this by the present value of incremental demand growth to estimate the LRMC.[54] It is usually calculated on a network-wide basis, noting that its estimate will ultimately be translated into a price that is applied uniformly across its network (postage stamp pricing).

50 AER (2023) *Draft Decision Ausgrid Electricity Distribution Determination 2024 to 2029 (1 July 2024 to 30 June 2029) Attachment 19 Tariff structure statement* p 16.

51 AER (2022) *Annual Pricing Process Review Final position paper – Side constraint mechanism,* p 2.

52 Ausgrid (2023) *Ausgrid's Tariff Structure Statement Compliance Document 2024-29*, p 41.

53 AEMC (2014) *Distribution Network Pricing Arrangements, Rule Determination*, 27 November 2014, Sydney, p, 118

54 Ibid p, 122.

While simpler to implement, it results in a higher estimate of LRMC because netting off growing and falling demand across the network acts to understate demand growth.[55]

However, with tariff reform, networks are increasingly exploring location specific LRMC methodologies as alternatives to AIC. The main alternative is the 'perturbation' or 'Turvey' methodology. This involves applying a small shock to a demand forecast, calculating the change in cost present value, and dividing by the demand increment to calculate the LRMC estimate.[56]

2.6. Network tariffs options

In consultation with their customers, DNSPs are free to design tariffs with a mixture of parameters and types so long as they are based on long-run marginal costs and provide mechanisms for efficient recovery of historical network residual costs. There are different types of network tariffs depending on the customer's location, demand, usage, metering, and whether the network has control over the customer's load.

Some common types are:

- **Flat tariffs:** are charges that apply at the same rate at all times of the day to the energy used by customers.
- **Demand tariffs**: These tariffs are based on your peak demand for electricity, measured in kilowatts (kW) or kilovolt-amperes (kVA). They are supposed to reflect the cost of providing enough network capacity to meet your demand.
- **Time-of-use (TOU) tariffs**: These tariffs vary depending on the time of day or season. They are usually higher during peak periods (when the network is more likely to be congested) and lower during off-peak periods (when the network has spare capacity).
- **Individually calculated tariffs**: These tariffs are tailored to specific customers who have large or complex electricity needs. They reflect the location-specific costs that these customers create for the network.

The full catalogue of potential tariff elements is detailed in Appendix A. DNSPs can encourage customers to transition to opt-in tariffs or deploy the new tariffs gradually for each design element. One of the more interesting tariff options is a transactive energy tariff. This a subscription-based tariff where customers "buy" their historical usage at the historical price and buy or sell deviations from that usage at the new tariffs on the wholesale market through HEMS or customer agents.[57]

While DNSPs can offer a catalogue of cost reflective tariffs for customers to opt into and can also deploy trial tariffs to provide innovative additional options for customer participation. We explain trial tariffs in section 2.9.

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55 Houston Kemp (2023) *Attachment 8.6: Long run marginal cost import methodology report Ausgrid's 2024-29 Regulatory Proposal*, p 1.

56 AEMC (2014) *Distribution Network Pricing Arrangements, Rule Determination*, p, 122.

57 Ahmad Faruqui and Ziyi Tang (2023), *Time varying Rate TVRs are moving from the periphery to the mainstream of electricity pricing for residential customers in the United States*, p 8-9.

2.7. The role of the retailer as a price intermediary

The DNSP charges network tariffs to Retailers. The final price charged to consumers is determined by how the Retailer responds to the price signals in the network tariff and how it repackages the network tariff in its retail offer. The DUoS charge makes up about 32 per cent of a typical residential customer's bill.

Retailers can package network tariffs into their retail offer in a way that replicates the network tariff price signals, but mostly they don't.[58] Retail offers are most often 'insurance-style', offering fixed daily and flat kWh energy charges, shielding end customers from price variability inherent in pricing that reflect network and energy wholesale costs.[59] Some retailers, for example, Amber Electric, allow the customer to choose their network tariff and passes this through at cost.

AER analysis has found that, in aggregate, on 30 June 2022, the proportion of residential customers on a cost-reflective network tariff across the NEM was 25.73%.[60] Its analysis of South Australian and Queensland customers in 2020 found most remained on flat or block retail offers without time-of-use price signals.[61]

A retailer's ability to pass on the network tariff will be subject to the metering arrangements at a customer's premises. Outside Victoria, non-DER customers often have legacy accumulation meters with no smart features capability.

The AEMC has recommended a target of universal take-up of smart meters by 2030 in NEM jurisdictions. When the AEMC asked retailers how they might respond to these arrangements, it found that medium and smaller retailers were more likely to pass through ToU network tariff structures as a way of managing their risk. Retailers are hesitant to pass complex tariff structures to end users, especially those with demand charges, as it's more difficult to explain to customers. Moreover, retailers are unlikely to actively promote alternative opt-in network tariffs to customers. Some retailers may seek to control customers' DER to manage cost exposures associated with demand-based network tariffs.[62]

Anecdotally, we understand legacy retailer billing systems impact their ability to pass on more complex tariffs. This is the same for networks. For example, Ausgrid is seeking to invest in new billing systems to be able to offer more dynamic and innovative tariffs to retailers.[63] Ausgrid's current billing system, for example will not allow it to pair customer demand measure (kW) with a usage charge (c/kWh).[64]

58 AER (accessed 19/09/23) *Network Tariff Reform*

59 AER (2020) *Understanding the impact of network tariff reform on retail offers,* p 3.

60 AER (accessed 19/09/23) *Network Tariff Reform*

61 AER (2020) *Understanding the impact of network tariff reform on retail offers,* p 2.

62 AEMC (2023) *Final report Review of the regulatory framework for metering services*, p 9.

63 Ausgrid (2023) *Attachment 5.7: CER integration program Ausgrid's 2024-29 Regulatory Proposal*, p 19.

64 Ausgrid (2023) *Our TSS Explanatory Statement for 2024-29*, p 56.

The pass-through of cost reflective network price signals by retailers is critical to customers realising the full benefits of flexible DER, including V2G.

2.8. Other requirements

The NER includes other requirements, including that solar customers cannot be put on export pricing arrangements until 1 July 2025 at the earliest (unless they elect to do so). DNSPs must develop and have an approved export tariff transition strategy describing any plans to phase-in export pricing over time. DNSPs are also required to comply with the AER's export tariffs guidelines.[65] These guidelines indicate AER approval for export charges will require DNSPs to demonstrate that supporting additional solar exports is increasing the costs of operating the network.[66] The AER also requires export tariffs to have a basic export level set based on intrinsic hosting capacity and expected demand for export capacity.[67] Customers can not be charged for exports below the limit.

The AER considers DNSPs should not recover historical network costs through export charges as they were primarily incurred for network consumption services. However, future network costs driven by export services should be priced similarly to consumption charges, with residual costs allocated appropriately.[68]

DNSPs must also comply with jurisdictional pricing obligations. For example, the Victorian Government requires all small customers with an EVSE to be assigned to cost reflective tariffs (such as time of use or demand charging).[69] In South Australia, the Government requires retailers to have a standing offer that includes a SAPN ToU tariff structure for residential customers and a SAPN demand tariff structure for prosumer residential customers.[70]

2.9. Trial tariffs

The NER includes, as a transitional arrangement over the next two regulatory control periods, an allowance for DNSPs to develop and trial new, innovative network tariffs in response to consumer requests or changing consumption or export patterns.[71] These arrangements permit DNSPs to implement new trial network tariffs that are under a materiality threshold within a regulatory control period.

The individual threshold is 1 percent of the DNSP's annual revenue requirement, and the cumulative threshold is 5 percent of the DNSP's annual revenue requirement. Trial tariffs serve

65 AEMC (2021), *Access, pricing, and incentive arrangements for distributed energy resources, Rule determination*, 12 August 2021, p 18.

66 AER (2023) *Export Tariff Guidelines – Explanatory statement*, p 3.

67 NER 11.141.12 and 11.141.13(b).

68 AER (2023) *Export Tariff Guidelines – Explanatory statement,* p 14-16.

69 AER (2021) *Attachment 19: Tariff structure statement | Final decision – AusNet Services, CitiPower, Jemena, Powercor and United Energy 2021–26*, p 7.

70 Government of South Australia (accessed 19/09/23). Tariff Structures

71 AEMC (2021), *Access, pricing, and incentive arrangements for distributed energy resources, Rule determination*, p vii.

as a potentially valuable input into TSS proposals, informing the DNSPs' benefit-cost, customer impact, and customer behaviour analyses.[72]

The trial tariffs can be introduced from the second-year annual pricing proposal, without the requirement to amend the TSS. The DNSP is not required to comply with the pricing principles for a trial tariff for the remainder of the regulatory control period, subject to the thresholds and compliance with the applicable control mechanism.[73] In some cases, the DNSP will use its demand management innovation allowance to guarantee customers will be no worse off on trial tariffs. For example, Ausgrid's residential two-way tariff trial has this guarantee as the network seeks to learn more about demand response to export charges and rewards.[74]

After the trial period, a DNSP is expected to report on the results of tariff trials and how this learning has been used for its future network tariff strategy. The DNSP can propose it as a new network tariff to be included in the TSS developed as part of the next regulatory determination process so that it can be assessed against the pricing principles. This is because the TSS developed at the start of the regulatory control period must contain all tariffs that the DNSP is planning to offer over the regulatory control period.[75]

2.10.Complementary non-tariff measures for improved network utilisation

DNSPs are increasingly utilising customer-owned DER to delay or avoid the need for costly network expansion including demand response, load control, dynamic operating envelopes, and community batteries.

The decline of direct load control

Some DNSPs offer discounted tariffs for the right to control selected loads, such as water heaters, that are located on a dedicated load control circuit.

Energy Queensland networks have used controlled load for hot water systems since the 1970s. This measure is broad-based in that it is available to customers across the network, rather than targeting specific areas with network constraints.[76]

As customers install solar, batteries, home energy management systems (HEMS), and EVs, they are increasingly wanting to self-consume their solar and actively manage their loads and exports for better financial outcomes. As such, there are fewer customers opting for DNSP direct load control. The number of hot water systems connected to load control tariffs in existing homes has been declining at a rate of 2-3% per year, and this is not being mitigated by

72 ibid.

73 Clause 6.18.1C of the NER.

74 Ausgrid (2022) *Ausgrid sub-threshold tariffs 2022-23 February 2022*, p 14.

75 AEMC (2014) *Distribution Network Pricing Arrangements, Rule Determination*, p 93.

76 Energy Queensland (2023) *Demand Management Plan 2023-24*, p 10.

new connections.[77] We understand that, as a result, Energy Queensland is reviewing this measure.[78]

The rise of emergency backstops

Like SAPN, Energy Queensland has an emergency backstop mechanism to address minimum system load. It uses a demand response enabled device called a 'generation signalling device', which will switch off generation from embedded generators (including export and self-consumption) in emergency events.[79] Rather than reflecting local constraints, these events occur at the transmission level and are initiated by AEMO via Minimum System Load (MSL) market notices.[80] Victoria will introduce similar arrangements in July 2024.

Dynamic operating envelopes

Dynamic operating envelopes (DOEs) are a widely accepted solution to network congestion and inefficient curtailment that results from static export limits. The advantage of DOEs is that it allows customers to export/import electricity up to the physical limits of the power system, as those limits change over the day or year, whereas 'static' export limits are more conservative as they are set on a worst-case scenario basis.

All mainland DNSPs in the NEM have plans to adopt DOEs for the purposes of dynamic export curtailment. SAPN, Victorian and Queensland DNSPs are also transitioning to the use of DOEs for solar backstop purposes. DNSPs can also use similar infrastructure for EV charging management. Smart charging solutions can help distribute the charging load more evenly throughout the day, reducing the impact on the network during peak times.

Community batteries

DNSPs and third-party suppliers are rolling out community batteries which reduce network congestion and capacity issues while offering economies of scale and lower costs for customers, especially those in apartments or non-homeowners.[81] This is being accelerated by the Federal Government's provision for $200 million for the Community Batteries for Household Solar budget measure. This policy intends to make it financially viable to deploy 400 community batteries across Australia.[82] A range of incentive and control frameworks are likely to be being considered to allow these assets to support local grids.

Investing in increased hosting capacity

Where pricing and supply/demand side measures are insufficient, there may be a need for the DNSP to invest in DER hosting capacity to support a broadening range of DER services.

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77 Ibid, p 27

78 Ibid, p 10.

79 Energy Queensland (accessed 19/09/23) *Emergency Backstop Mechanism*

80 AEMO (2021) *MSL & DPVC Market Notices*, pp 1-5.

81 AER (2020) *Updating the Ringfencing Guidelines for Stand-Alone Power Systems and Energy Storage Devices Issues Paper November 2020*, p 23.

82 ARENA (accessed 19/09/23) *Community Batteries Funding Round 1*

However, this is not a good option in many cases and the AER views it as a last resort. Accordingly, the AER requires that networks fully justify DER integration expenditures by quantifying their benefits, not just to the network but to the broader electricity system. This includes the impact DER can have on the wholesale electricity market.[83]

The Value of DER (VaDER) methodology is used by the AER to assess DER value streams and the types of costs and benefits that may arise because of a network investment to increase DER hosting capacity.[84] Network value streams may include avoided or deferred transmission/distribution augmentation, avoided network losses, or improved reliability. Other streams cover environmental consideration - avoided greenhouse gas emissions and customer benefits (for all customers, not just DER customers).[85] Recent changes to the National Electricity Objective increase the scope for including emission reduction benefits in network expenditure proposals.[86]

Wholesale market benefits are captured by the DNSP's avoided generation capacity investment estimates (through electricity market modelling and the DER alleviation profile[87]) and the AER's CECV methodology.[88] Under the CECV methodology, CECVs capture the value of the avoided marginal generator SRMC (including an approximation of the value of FCAS).[89]

To demonstrate the efficacy of network investments, the AER requires DNSPs to compare the proposed expenditure against the sum of benefits under each value stream (where applicable).[90] This generally results in poor or nil benefits of networks investing in increase solar network hosting capacity.

83 AER (2022) *DER integration expenditure guidance note*, p 4.

84 Ibid, p 18.

85 AER (2022) *DER integration expenditure guidance note*, p 19.Ibid, p 19.

86 AEMC (2023) *How the national energy objectives shape our decisions*, p 13.

87 The forecast of additional DER penetration and system size will impact the use of existing headroom and curtailment, without DNSP investment. The number and operation of behind-the-meter batteries/EVs will influence solar generation and export to the grid. New and evolving tariffs and price signals should be considered for the alleviation profile. See Oakley Greenwood (2022*). AER final customer export curtailment value methodology, June 2022*, p 14.

88 Ibid.

89 Ibid, p 20.

90 Ibid.

3. Selected modelling period and region

enX selected Ausgrid (NSW) as the reference area for this study. Ausgrid is Australia's largest electricity distributer and a member of this project's DNSP Reference Group.

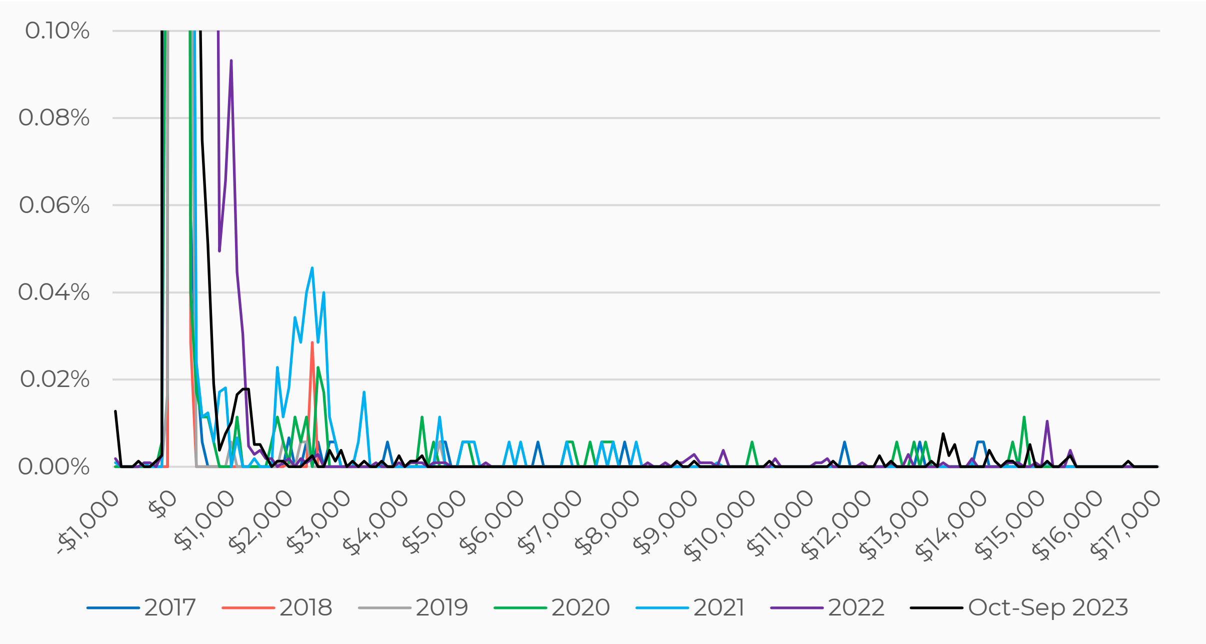
We selected the period 1 October 2022 to 30 September 2023 for modelling purposes due to it being relatively contemporary and to avoid 2022 wholesale market price disruptions associated with the invasion of Ukraine and local market interventions.[91]

Table 1 shows that while October 2022 to 30 September 2023 had substantially lower prices than calendar year 2022, prices remain elevated compared to historic years. Figure 3 illustrates this period is generally closer to historic price spreads than 2022, but with more instances of market floor (-$1000) prices. It is not possible to reliability assess the extent to which the selected period is representative of future pricing given uncertain future market dynamics. However, this period appears the most representative of future grid and energy market dynamics, compared to other years.

Table 2 – Summary assessment of network tariff elements shortlisted for modelling purposes

Year	Cal 2017	Cal 2018	Cal 2019	Cal 2020	Cal 2021	Cal 2022	Oct-Sep 23
Average	$95.48	$82.33	$84.85	$59.95	$72.60	$182.71	$106.15

Figure 3 — Count of NSW electricity spot market trading intervals settling in different price bands 2017-YTD (% of total intervals)



[91] See AEMO (2022) *Quarterly Energy Dynamics Q3 2022*

We asked Ausgrid to nominate a suitable location to assess the potential impact of alternative network tariffs on V2G operation and outcomes for networks, consumers and Ausgrid.

It identified the Metford substation and provided load data for analysis. Metford was considered suitable due to it being relatively peaky (including reverse power flows) and having a high percentage of standalone residential dwellings, with solar, whose occupants may be early adopters of V2G technology.

The Metford substation, in the selected period, has the following features:

- Maximum firm capacity = 41.6 MW
- 93% residential (typically standalone detached dwellings)
- 1.96 kW average solar installed per connection
- 0.38 load factor
- Increasing reverse power flow incidents, especially during the Spring season (68 hours total for the selected year)
- 12% forecast decline in summer peak demand from 2023 to 2033
- 9% forecast growth in winter peak demand from 2023 to 2033

The results of our modelling are intended to be illustrative of how network pricing can be used to activate network support from V2G at substation like Metford, where peak load is of concern to system planners and there is significant capacity for V2G uptake.

Figure 4 illustrates the relationship between temperature and maximum demand at Metford substation. This shows peak demand is generally associated with the hottest days (and typically weekdays). **Figure 5** shows the annual demand profile (15-minute resolution) compared to firm capacity and that that peak demand in the selected year occurs in February and March corresponding to heatwaves in those months.

Figure 4 — Relationship between daily maximum temperature and substation daily maximum demand at Metford substation for the period October 2022 to September 2023.

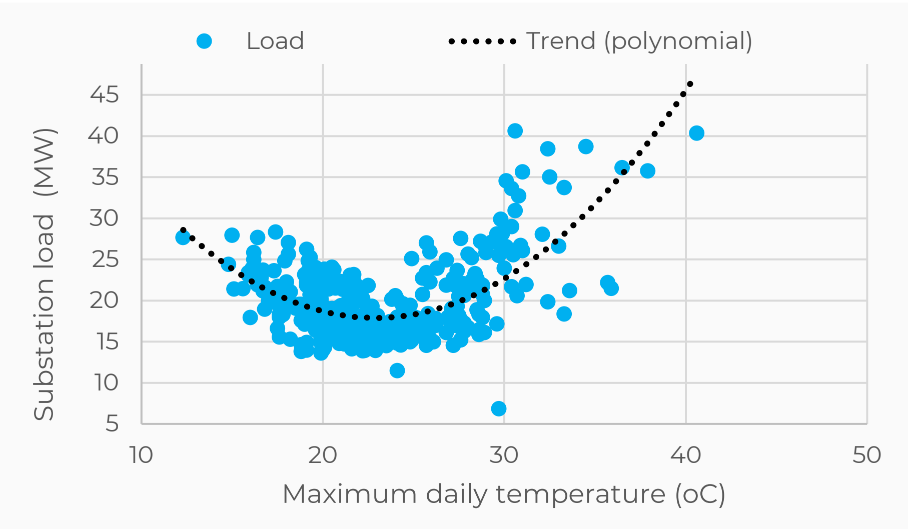
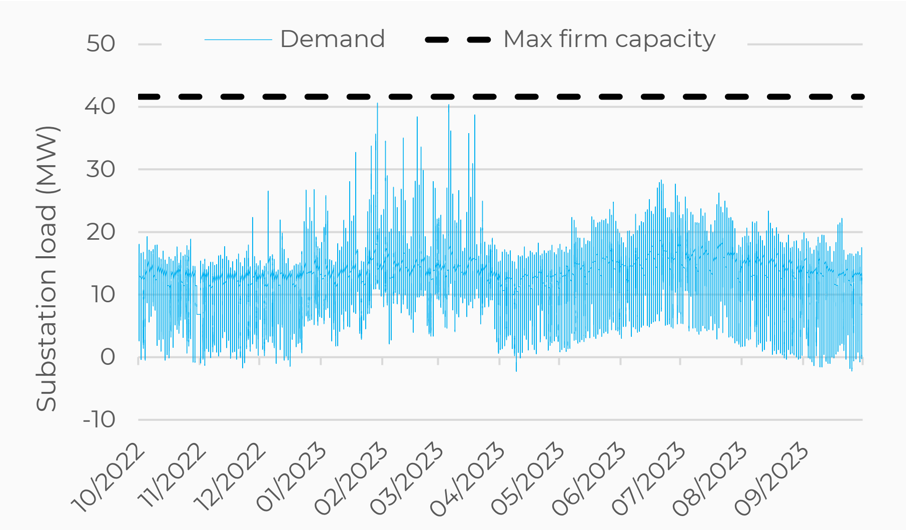


Figure 5 —Metford substation load profile for the period October 2022 to September 2023 and rated maximum firm capacity (summer & winter).



4. Tariffs selected to model V2G operation

4.1. High-level considerations in V2G network tariff selection

The NER pricing objective and pricing principles provide an appropriate (and necessary) reference for designing tariffs for V2G participation. However, these principles do not capture the full range of insights gained from DNSP engagement with customers in TSS consultations and the learning from recent network tariff trials. A broader perspective is needed to consider the characteristics of tariffs suited to V2G operation.

The AER has taken a reasonably conservative approach to network tariff decisions due to the inherent trade-offs against each of the pricing principles and other considerations. We are moving to a new regulatory operating environment where tariff decisions will be assessed against not only the pricing principles but also emissions reduction targets. In NSW, this includes 2030 of 50% greenhouse gas emissions below 2005 levels, 12 GW of VRE by 2030, and, relevantly, for tariff design, a peak demand reduction of 10% by 2030.[92]

Additionally, the AER is now faced with highly price-responsive, automated smart CER technologies that can respond to prices dynamically. This means customers' demand and price elasticity is higher than ever envisaged before.

This study focusses on residential tariffs to support efficient V2G operation, and we compare options in relation to three factors:

1. Efficiency and fairness – Price signals should:
    - *Provide incentives* to consumers to adjust generation and usage patterns to reduce their own costs and contribute to future network cost reductions. This can be achieved when prices are based on marginal costs.
    - *Minimising cross-subsidies* – the costs of network services should also be recovered from the parties who benefit from them. For example, customers that contribute to high peak demand (and network costs) should pay more, while customers that reduce peak demand (through load management or exports) should be rewarded.
    - *Technology neutrality* - Tariffs should reward and charge for service value, rather than how the service is provided.
2. Market fit – For network tariffs to be effective, they must be:
    - *Appropriate for the customer* – Networks and retailers can provide a range of tariffs to suit different customer needs and preferences. This could include flatter tariffs for consumers who prefer simplicity (potentially at a higher cost) and more complex and dynamic tariffs for customers who are able to be more flexible in energy demand and generation.
    - *Appealing* – to influence customer electricity usage, tariffs need to be taken up by consumers. That might mean they need to be simple enough to understand, and 'actionable' in that customers can actually change their behaviour to obtain a meaningful benefit.

92 AEMC (2023) *Emission target statements under national electricity laws*, pp 1-3

3. **Social equity** – Networks must consider broader social equity outcomes, especially when considering the geographical smoothing of residual cost recovery and price incentives.

These factors can create tensions that cannot be resolved with economics alone. Networks must use their experience and judgement, drawing on trial learnings and effective consultation with stakeholders as is intended (and required) under regulated TSS processes.

In our modelling, we focus primarily on efficiency and fairness, leaving open the possibility that our modelling results and conclusions may not fully address market fit and social equity. Our results therefore need to be viewed as an input into tariff design discussions rather than a 'final word'.

4.2. Selecting network tariffs for V2G optimisation modelling purposes

A full summary of the benefits and limitations of different tariff structures and elements is provided in *Appendix A – Summary of key network tariff types and tariff elements* on page 79. Based on this assessment, we shortlisted 5 tariff elements for modelling purposes, as summarised in **Table 3**. Of these, demand tariffs were discarded due to a relative misalignment with this study (they both do not incentivise efficient V2G operation and have low market acceptance).

Table 3 – Summary assessment of network tariff elements shortlisted for modelling purposes

Tariff type	Efficiency and fairness	Market fit
Unidirectional ToU Pricing for load is time-based.	Moderate – Unidirectional ToU tariffs provide a variable price signal for load (typically by time-of-day and season) that encourages demand reduction (but not exports) at peak demand times. The major shortcoming of ToU tariffs is that they operate on a fixed schedule irrespective of actual grid conditions, so they will inevitably over or under incentivise demand reductions most of the time.	Moderate – Commonly offered and able to be accommodated by existing retailer billing systems.
Bidirectional ToU Pricing for load and generation is time-based.	Moderate – Bidirectional ToU tariffs provide a variable price signal for load and generation (typically by time-of-day and season) that encourages demand reduction and exports at peak demand times. The major shortcoming of ToU tariffs is that they operate on a fixed schedule irrespective of actual grid conditions so, they will inevitably over or under incentivise demand reductions and exports most of the time.	Moderate – An incremental extension to Unidirectional ToU and likely able to be accommodated by retailer billing systems. Currently available as a trial tariff.
Dynamic tariffs Pricing for load and generation is based on actual network conditions.	High - Allocates costs fairly and provides precise incentives for load shifting and self-consumption, and exports.	Low – High complexity and risk makes it suitable only to customers with automated price responsive DER (e.g. V2G), where it may be attractive. Good fit for these customers. Not currently available.

Demand charges	Low – Demand charges provide an incentive to limit demand peaks, rather than self-consume generation or export in a way that supports broader positive grid outcomes. As they do not change with actual grid conditions, they over or under incentivise customer participation most of the time.	Low – Demand charges are complex and create high cost-risk exposures which can cause wide variations in cost between billing periods. This is reflected in low uptake by retailers and residential customers.
Daily supply charges	High – Daily supply charges are highly suitable (only) for the recovery of residual costs. They do not enhance or distort operational incentives (based on marginal costs). However, they can be priced based on the 'size' of a customer's connection (e.g. single or three phase), in keeping with LRMC considerations.	High – Daily supply charges are commonly used in existing retail products

Based on this assessment, we selected the following tariffs for modelling purposes:

- Unidirectional ToU
- Bidirectional Tou
- Dynamic tariffs
- Daily supply charges

4.3. Selecting energy price structures for V2G optimisation modelling purposes

Network tariffs do not operate in isolation. They are typically bundled within a broader retail price package that accounts for energy purchase costs and a range of other fees and overhead costs that retailers are subject to. Customers with V2G will be exposed to this bundled pricing, and V2G operations can be expected to optimise against the sum of price incentives.

The same principles for network tariff selection (see page 35) also apply to retail package design. However, when selecting a retail price structure for modelling purposes, it is important to recognise that electricity retailing is a competitive market, so the relative total package pricing of retail offers also needs to be considered. We have considered this under the heading of 'market fit' in Table 4 below.

Table 4 – Summary assessment of retail tariff elements shortlisted for modelling purposes

Price structure	Efficiency and fairness	Market fit
Flat rate	Very Low – While flat retail tariffs remain popular with many consumers, they do not provide any incentive for grid or customer-friendly V2G (or battery) operation.	Very Low – For customers on a flat tariff, V2G can only increase costs (associated with round trip electrical losses).
ToU	Moderate – Bidirectional ToU tariffs provide a variable price signal for load (typically by time-of-day and season) that encourages demand reduction (but not exports) at peak demand times and encourages solar self-consumption. Export pricing is typically based on a flat rate feed-in tariff (FiT). The major shortcoming of ToU tariffs is that they operate on a fixed schedule irrespective of actual grid conditions so they will inevitably over or under incentivise demand reductions and exports most of the time. This issue becomes more severe as instances of countervailing wholesale and retail pricing increase.[93]	Moderate – Commonly offered and able to be accommodated by existing retailer billing systems, although many consumers prefer flat rate 'insurance-style' tariffs.[94]
Spot pass-through	High - Allocates costs fairly and provides precise incentives for load shifting and self-consumption, and exports based on real-time wholesale market pricing. Previous modelling by enX indicates that they can be highly preferable for customers with flexible DER including large batteries and V2G.[95]	Low – High complexity and risk may make it suitable only to customers with automated price responsive DER (e.g. V2G), where the price risk is able to be managed. Good fit for these customers.
Daily supply charges	High – Daily supply charges are highly suitable as a way of passing network and retail fixed costs. They do not provide or distort operational incentives (based on marginal costs).	High – Daily supply charges are commonly used in existing retail products

Based on this assessment, we selected the following energy pricing structures for modelling purposes:

- ToU
- Spot pass-through
- Daily supply charge

4.4. Price structure combinations selected for modelling purposes

Our review of potentially suitable network tariffs and retail pricing structures resulted in the selection of six network and retail pricing combinations (scenarios) for modelling purposes.

93 See Leemon, A. (accessed 7/12/2023) *Currently Speaking – Get Low*

94 Energy Consumers Australia (2022) Retail Pricing Reform has been painfully slow. Why might that be? (accessed 7/12/2023).

95 enX (2023) *V2X.au Summary Report Opportunities and Challenges for Bidirectional Charging in Australia,* p 3.

These are summarised in Table 5. All pricing is for NSW postcode 2323 (Metford, NSW) to align with the focus region for network power flow modelling.

Three selected network tariffs:

- Ausgrid EA025 – This is Ausgrid's default unidirectional ToU tariff for residential customers
- Ausgrid EA025 + EA029 – This includes an additional ToU export tariff proposed by Ausgrid for FY25
- Dynamic network – This was constructed based on a load trace for the Metford substation. It provides a 5-minute dynamic price inversely correlated to available network capacity.

Two selected retail price structures:

- Origin Go (residual) – The Origin Go retail product was considered relatively competitive. A residual retail cost was calculated by netting out Ausgrid's default ToU tariff (EA025).
- Amber Electric – Amber[96] has pioneered spot pass-through pricing for residential customers in Australia. They have provided details on their pricing structures to enX for the purposes of this study. Amber provides spot price passthrough pricing (currently 30-minutes average), a monthly subscription fee, and passthrough of other cost elements (including network tariffs). 5-min NSW region spot market pricing was used for the modelling period.

More information is provided in *Appendix B - Details for each modelled tariff* from page 86.

Table 5 – The six network and retail tariff element combinations selected for modelling purposes

		Energy pricing	
		ToU Energy	Dynamic energy
Network pricing	Unidirectional ToU	**1** Origin Go (residual) Ausgrid EA025	**4** Amber Electric Ausgrid EA025
	Bidirectional ToU	**2** Origin Go (residual) EA025 + EA029	**5** Amber Electric EA025 + EA029
	Dynamic	**3** Origin Go (residual) Dynamic network	**6** Amber Electric Dynamic network

96 www.amber.com.au (accessed 7/12/2023).

5. Dynamic pricing methodology

Dynamic pricing takes LRMC-based pricing to its natural limit by pricing generation and demand that is directly driving network LRMCs, rather than approximating it. In Australia, dynamic pricing is being pioneered by Ausgrid through their Project Edith trial.[97]

Dynamic network pricing has several inherent features:

1. Charges vary depending on current and local network conditions.
2. They apply only to variable network costs, so most of the time, when the grid is unconstrained, network variable charges can be very low, or zero. They would not normally include residual network costs, and these need to be recovered through other means, such as daily supply charges.
3. They provide an alternative to networks centrally procuring (and dispatching) grid support services and support 'distributed optimisation' (see section 1.3, p.12).
4. They are relatively complex, pointy, and highly variable, and retailer uptake and mainstream consumer acceptance are yet to be tested. They will only be beneficial for customers that have low price risk exposure, including where that risk is managed using flexible CER such as large batteries or V2G capable of optimising against, and responding to, real-time pricing.
5. Peak pricing must be sufficient to ensure a **firm response** during critical periods. There is no point in offering dynamic price signals if customers do not respond when and where they are most needed.

5.1. Ensuring a firm response, market floor price consideration

Firmness is a key consideration when setting a dynamic price. This has been addressed in our model in two ways:

- Ensuring realistic estimates of vehicle availability during critical peak events
- Ensuring compensation payments are sufficient.

Given that customers opting for dynamic network pricing will generally have automated and bidirectional DER, it is likely that those resources will be used to manage an electricity spot market exposure.[98] In this case, the network price signal must be strong enough to overpower any current or expected countervailing spot market price that could result in the consumer withholding generation when it is needed.

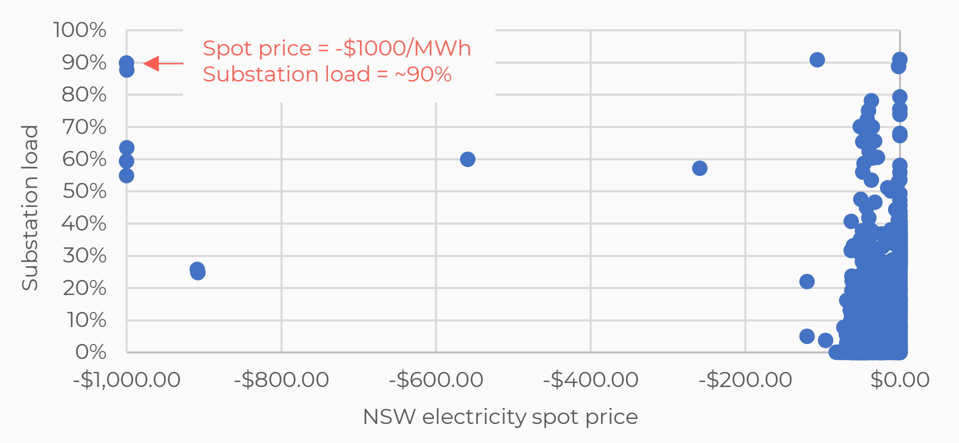
A particular risk is where the spot market drops to the market floor (-$1000) during a local critical peak event. This would push price-responsive loads like V2G into charge mode,

97 Ausgrid (accessed 5/12/2023) *Project Edith*
98 Previous analysis indicates spot passthrough tariff are highly beneficial to V2G-capable customers. See enX (2023) *V2X.au Summary Report Opportunities and Challenges for Bidirectional Charger in Australia,* p 3. Spot exposure could be via a retailer, VPP or spot pass-through tariff.

exacerbating peak demand. The network export incentive must be greater that $1/kWh to offset the import incentive created by the wholesale market during a MFP event.

Figure 6 shows that very low spot prices can occur when a local substation is heavily loaded. Whiles these events are rare, they may occur more frequently over the coming decade as negative spot prices become more common. There is also some theory and evidence that negative pricing instances will increase into the future for as long as we have large inflexible loads (like coal generators) able to set market prices.[99]

Figure 6 – Loading of the Edgeworth substation on the Ausgrid network (Newcastle, Sept- Oct 2023) against instances of negative spot market prices in NSW. Each dot represents a 5-minute trading interval.



Occasional miscorrelation between network load and spot market pricing may occur due to localised weather conditions driving high demand on a substation, during a period of abundant renewables generation in the broader market. Market bidding dynamics can also deliver a wide range of price outcomes under comparable conditions.

The market floor price is also arbitrary. In setting it, the AEMC reliability panel may only recommend an MFP, which it considers will:

- Allow the market to clear in most circumstances, and
- Not create substantial risks that threaten the overall stability and integrity of the market.[100]

In 2022, the Reliability Panel determined that '*adjusting the level of the MFP is not warranted in the absence of a clearly identifiable benefit over the review period*' and '*there was unacceptable risks associated with a more deeply negative MFP*.'[101] The reliability panel does not consider the benefits of increasing the market price to assist distribution networks

99 See for example Leemon, A. (accessed 7/12/2023) *Currently Speaking – Get Low,* and AER (2023) *State of the Energy Market*, p.44

100 AEMC Reliability Panel (2021) *Review of the reliability standard and settings guidelines - final guidelines*

101 AEMC Reliability Panel (2022) *2022 RSS Review Final Report*

integrate higher penetrations of distributed generation resources, or efficient economic outcomes more broadly.

Setting network prices against worst case and rare coincidences of wholesale market and local network conditions creates costs to networks. This may be a worthy consideration in future Reliability Panel deliberations.

5.2. Variable price settings

We have chosen an ‘insurance approach’ to setting dynamic pricing whereby, it is set to offset any countervailing wholesale price signal. Considering an MFP of -$1/kWh, we have selected a peak price of $1.20/kWh which resolves to a $0.20/kWh net discharge incentive.

This peak price is reached wherever the network reaches a critical peak load (e.g., 80% of a substation’s firm capacity) and declines in direct proportion to load until it achieves zero at a comfortable load point (e.g., 60% of firm capacity). This pricing applies symmetrically to load and generation during peak demand periods (load is charged, generation is paid) reflecting that generation can reduce network costs either by generating more or consuming less. Customers would be paid whenever they exported to the grid, based on the symmetrical dynamic charges.

This approach reflects a potential SRMC for the customer - the opportunity cost of not responding to a current or expected future electricity market price signal.

Under our approach, a customer who makes no contribution to increasing or decreasing electricity demand during critical pricing periods would expect to have no variable charges.

Variable dynamic prices were only applied to mitigate maximum demand issues. Minimum demand constraints were addressed using only DOEs, which were applied equally across all modelled scenarios (see Chapter 6). In principle, similar outcomes could potentially be achieved by applying dynamic export charges.

5.3. Residual cost setting

Residual costs are sunk costs that are unaffected by future consumer load and generation. As such, they need not vary over time. For the purposes of this study, these are recovered through a daily supply charge of $1 per day, which is within the range of current pricing by DNSPs.

This is a relatively arbitrary amount that can be varied ex post without affecting other modelling results. Daily supply charges can be expected to be higher where variable charges are based solely on network variable costs, rather than also including an allowance for the recovery of residual costs.

6. Use of Dynamic Operating Envelopes

Dynamic Operating Envelopes (DOEs) are an Australian invention used to manage very high penetrations of rooftop solar and, in the future, large flexible loads. DNSPs place limits on how much customers are allowed to export. Historically, these limits have been static (fixed) and are set based on maintaining integrity in all network conditions including, peak net export times (representing worst-case scenarios), which occur rarely. DOEs provide a more efficient approach to managing network capacity by allowing DNSPs to vary customer export limits dynamically. They allow customers to export more electricity and limit exports only when necessary.[102]

Flexible export limits are DOEs that apply only to exports. They are currently being offered in South Australia, with Queensland and Victorian network businesses offering them in 2024. NSW has plans to implement DOEs in its next regulatory control period.[103]

Initial test modelling runs of V2G under spot passthrough tariffs indicated that price incentives may not be sufficient to ensure stable, grid-friendly charge operation. During periods of price volatility, we found that vehicles responded sharply and that after periods of sustained high pricing, EV charging could rebound, creating secondary peaks that had the potential to threaten grid limits.

We made the decision to simulate DOEs to provide an additional level of control. This was applied to all modelling scenarios to avoid potential distortions in comparative power flow and cash flow analysis.

6.1. How DOEs were applied

The following dynamic limit ranges were applied:

- Export limits – 1.5-10 kW
- Import limits – 1-23 kW.

Synthetic DOEs were calculated as a function of network load. Specifically, import limits were applied once the substation load reached 60% of its rated firm capacity and tightened in proportion to the remaining capacity. Export limits were applied once substation load dropped to 25% of rated firm capacity and tightened in proportion to the remaining export capacity. This is illustrated in **Figure 7** below.

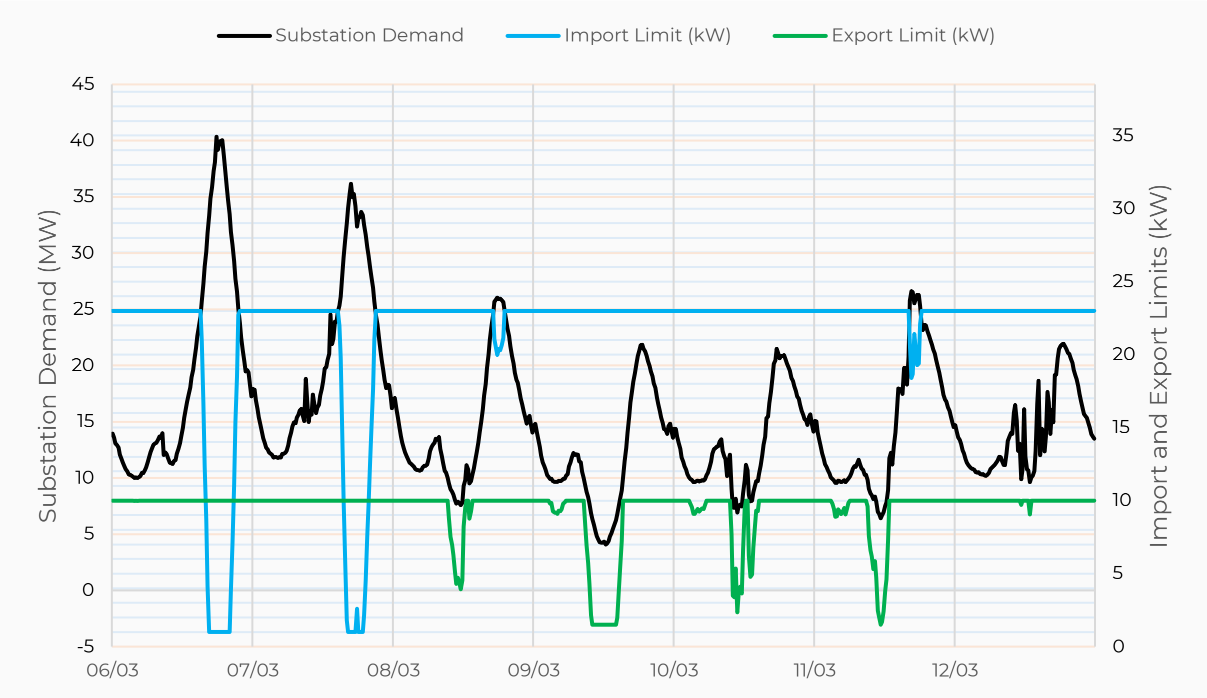
While these limits were issued at the site level (e.g. applying to all generation and load) the modelling only constrained the import or export of flexible resources. For example, where a 1kW import limit was applied, the customer would be in theory able to use 24kW, if they had 23kW of inflexible (uncontrolled) load. This can be described as a 'soft limit' on imports as it only applies to flexible resources nominated by the customer for dynamic import

102 DEIP (2022) *Dynamic Operating Envelopes Working Group Outcomes Report*

103 enX is supporting collaboration between network businesses towards national frameworks for public key infrastructure (PKI) and product (inverter) certification to support DOE implementation.

management. Site-level import and export limits promote EV charge load shifting, and self-consumption of solar generation, regardless of the financial incentive structures in place.

Figure 7 — Example of both import and export limits calculated for Metford substation during the week 6-12 March 2023. This week had both very high peak and very low minimum demand.



Over the course of the year, import and export limits were seen to bind in 0.47% and 1.47% of trading intervals respectively. In contrast, these limits were much higher during the modelling week, being 9.8% and 16.4% respectively. Export limits were above 5 kW for 82% of the year, and never dipped below 1.5 kW.

Export limits were based on arbitrary assumptions about export curtailment requirements at the Metford substation, which may be able to be relaxed depending on actual substation conditions.

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7. Customer load and, solar and EV technology assumptions

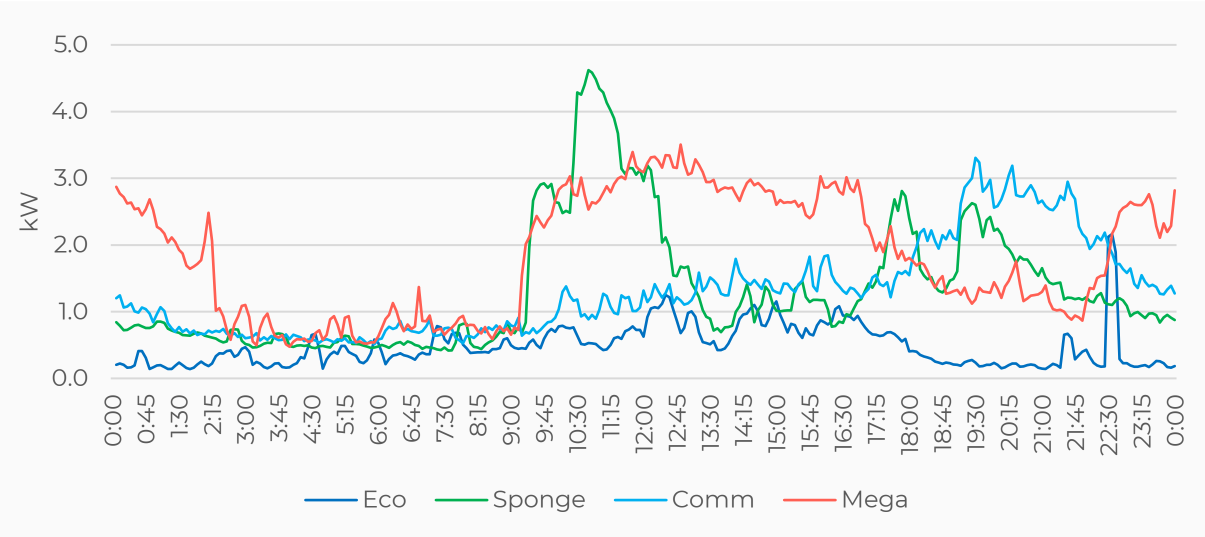
7.1. Customer load profiles

Four synthetic 5-minute customer load profiles were constructed for the modelling period, representing a range of user types with different energy and network price exposures. These profiles represent the electricity consumption of the customer *without solar* or any other price responsive generation or load.

The four user profiles are:

- **Economy user** – low electricity usage throughout the year. 3.84 kW peak demand and 2.24 MWh annual consumption
- **Sponge user** – very high daytime consumption with a secondary peak in the evening. 9.37 kW peak demand and 11.73 MWh annual consumption
- **Commuter user** – relatively low daytime, and high evening consumption. Peak demand of 11.3 kW, annual consumption of 11.41 MWh
- **Mega user** – High daytime and overnight usage. 12.72 kW peak demand and 16.09 MWh annual consumption.

Figure 8 — Average of synthetic daily load profiles for each user types



The synthetic profiles were derived from historic 5-minute interval data for different customers in NSW from 2021 and 2022. Actual data was used for the period 1 October to 31 December 2022. For the period 1 January to 30 September 2023, historic daily load profiles were used based on matching the day of week (weekday or weekend) and maximum daily temperatures. This generally resulted in aggregate customer demand being high at times of high Metford substation load, on a time-of-day and seasonal basis.

While this approach is considered sufficient for the purposes of this study, it is important to stress that individual user results cannot be generalised to the broader population.

7.2. Solar assumptions

It is an assumption of this study that early adopters of V2G are most likely to live in standalone owner-occupied residential dwellings and have solar.

The assignment of solar installations to customers varied by modelling run:

- For the **power flow modelling** we modelled 520 residential premises and customers were randomly assigned PV installations between 2.5 kW and 14 kW based on APVI system size distribution data for the Metford area postcode[104].
- For the **revenue modelling** the three customers (Economy, Commuter & Sponge users) were assumed to each have a 7 kW (DC) solar system with an inverter rated capacity of 7 kW (AC).

Generation was derived from solar irradiance for the Metford area for our modelling period (October 2022 to September 2023), as an output of the model.

No other flexible loads or batteries were assumed to be on site.

7.3. EV usage and charger assumptions

Each customer was assumed to have:

- An EV with usable battery storage of 59 kWh
- An EV smart charger with a bidirectional rated capacity of 7.4 kW
- 5.2 kWh (~30 km) of daily EV usage
- A minimum state of charge (SoC) preference of 40% usable battery capacity

7.4. Optimising V2G operation

The Grigcog platform[105] was used to simulate V2G operation as though it were exposed to the price signals in each scenario. Important modelling setup features include:

- There is no participation in frequency control ancillary service markets. Previous enX modelling indicates this is likely to make the revenues from V2G operation slightly conservative (<$50 pa.)
- A 24-hour rolling forecast window was used which is consistent with several HEMS products in the Australian market.
- Round trip losses of 15% for battery operation[106]
- Minimum SoC constraint whereby the optimiser will seek to keep the battery above 40% SoC as an assumed user preference.

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[104] APVI (accessed 3/11/2023) *PV postcode data*

[105] www.gridcog.com

[106] This is considered moderately conservative when compared with available empirical data. See for example Schram N. et al (2020) *Empirical Evaluation of V2G Round-trip Efficiency*

Forecast uncertainty in the Gridcog model can apply to pricing and/or load[107]. We applied a:

- 20% load shape forecast uncertainty whereby the optimisation occurs against a forecast load trace that is perturbed by up to 20%
- 20% price forecast uncertainty whereby the optimisation occurs against a forecast price trace that is perturbed by up to 20%.

In early modelling runs, we found that the Gridcog model undertook quite 'aggressive' optimisation in the spot passthrough scenarios, arbitraging effectively against relatively small price movements. We tempered this operation to address concerns that V2G battery warranties may not cover this level of activity. This was achieved by the use of an appropriate, arbitrary, penalty cost on EV battery discharge, which brought operation more in line with household battery data, which was observed via battery telemetry data for customers in the Amber SmartShift program.

[107] Gridcog (accessed 12/12/2023) *Nobody's Fool: Weaving uncertainty into the fabric of our modelling*

8. Estimating vehicle availability

Unlike stationary batteries, EVs are inherently mobile and cannot be assumed to be at home and plugged in at any point in time. To address is issue, we developed a series of vehicle availability schedules based on a model that determines the likelihood of a vehicle being at home at plugged in any 30-minute interval over the course of a week. While availability is 'random' for an individual vehicle, as the number of vehicles grows, the average availability starts to conform to an assumed average profile.

Our modelling approach takes vehicle availability as an input and produces charging (and discharging) profiles as an output. Unfortunately, there is no reliable and publicly available data on residential EV plug-in behaviour, including among the substantial knowledge-sharing outputs from ARENA, local and international trials. Plug-in behaviour cannot easily be derived from publicly EV charging profiles as these most often include 'session start and end times' that are based around smart charging schedules rather than when the vehicle is plugged in.

We developed a population level target profile of for plug-in behaviour based on:

- ABS road user data for Sydney[108]
- Aggregate charge profile data provided by Tesla
- Energex SmartCharge report[109]
- Vector NZ mart charging trial outcomes[110]
- AGL EV smart charging trial outcomes.[111]

Overall, the data indicates that EV owners are most likely to plug in in the afternoon and evening and later in the working week and they are more likely to be plugged in on the weekend, which aligns with our expectation that many early EV adopters will seek to charge their vehicles off solar when they can.

From the data, we were able to estimate plugin behaviour for work-from-home (WFH) and commuter users. They were weighted 30% and 70% respectively[112] and combined to form a population-level commuting pattern. For V2G users, we assumed that vehicles were likely to be 10% more available than their smart charging cousins. This is based on the outcome of V2G a trial of 300 residential customers in the UK, which found that consumers are significantly more likely to plug in when there is a financial incentive to do so.[113] We did not account for public holidays. The outcome of this work was *population-level weekly target profile* of EV availability in 30-minute intervals.

[108] xxx

[109] Energex (2023) *EV SmartCharge Queensland Insights Report*

[110] Vector (2022) *EV Smart Charging Trial ESIG Webinar*

[111] AGL (2022) *EV orchestration trial lessons learned report 4*

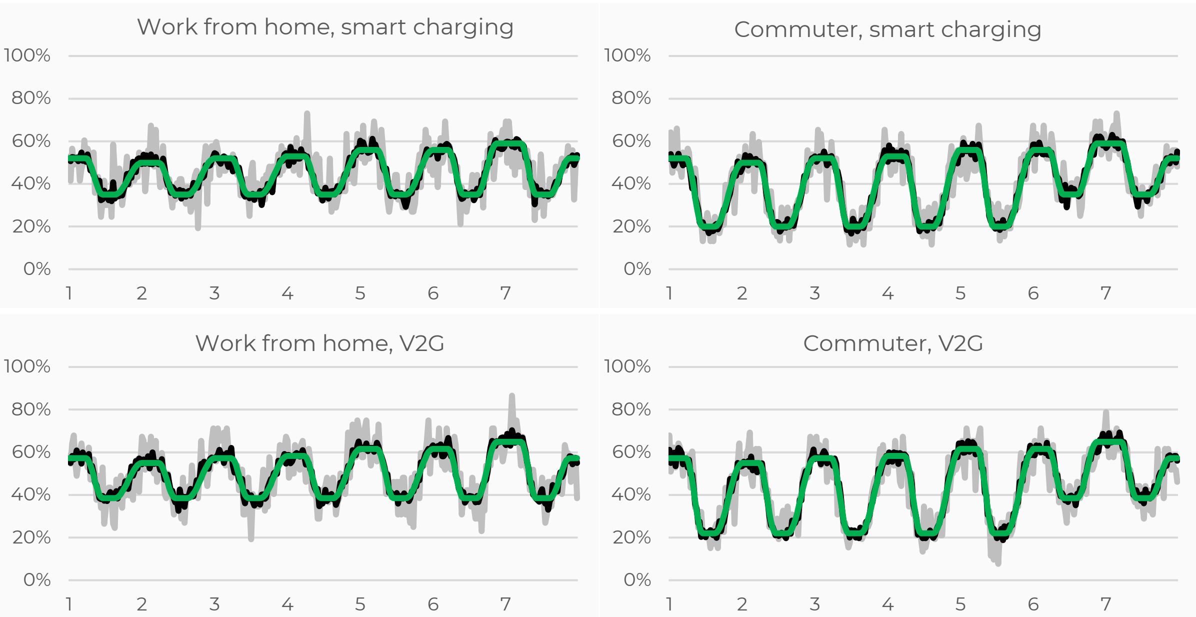
[112] In September 2022, workers in NSW, spent approximately 31.4 percent of their total working days working from home. Source: *Statista* (accessed 14/12/2023)

[113] Cenex (2021) *Project Sciurus Trial Insights*

Sciurus-Trial-Insights.pdf (cenex.co.uk)

Figure 1 shows the population target profile for vehicles over the course of a week and how the availability profile of a fleet of vehicles conforms to the target as the sample size increases. While not a specific focus of this study, this method allows for diversity factors to be considered at different system scales and with different levels of EV penetration, and for Montecarlo analysis to be conducted to estimate the coincidence of vehicle availability with other factors (e.g., peak demand events)

Figure 9 — Fleet availability of an V2G-capable EVs every 30 minutes over the course of a week (day 1 is Monday). The grey lines exhibit stochastic variability that is more pronounced in smaller sample (fleet) size (grey line). This tends to smooth out as sample size increases (black line) until it converges on the target profile (green line). Each week in a modelling period has a different (but broadly similar) profile.



9. Powerflow analysis method and results

A central objective of this study is to identify the ways in which tariffs and pricing affect V2G behaviour and the resulting impact on distribution networks. We explore this in the context of a specific critical peak demand week (of 6-12 March 2023) on the Ausgrid Metford substation and model the effect on peak (and minimum) demand. This is a measure of the effectiveness of V2G under different tariff and pricing arrangements in delivering savings to network businesses and consumers on that network. The result from this analysis is generally applicable to other network areas with similar characteristics.

9.1. Approach to powerflow analysis

Modelling was undertaken using the Gridcog modelling platform[114] which is simulates the optimisation of flexible load and generation resources under user-specified conditions. Gridcog was used to:

- Produce location and time-specific solar generation profiles for each user site
- Simulate the optimisation of smart charging and V2G against the relevant tariff arrangements. This is based on a 24-hour-ahead rolling optimisation
- Calculation of resulting EV load (and generation) profiles for each user site
- Calculation of discounted cashflows

The week of 6-12 March 2023 was selected for a case study investigation of the potential roll V2G could play in mitigating network peak (and minimum (demand. This week had the highest peak for the October to September 2023 year (40.35 MW, 97% of firm capacity) and had significant low minimum demand ((4.08 MW, 10% of firm capacity). The substation load profile for this week is shown in Figure 7 on page 44.

520 unique 'customer weeks' were constructed representing a combination of:

- Customer load profiles (matched to daily maximum temperature)
- Solar installations
- Vehicle availability profiles

Each customer grouping was assigned the 6 different tariffs scenarios selected for modelling (see *Tariffs selected to model V2G operation*, p.35). This resulted in 3120 unique user/tariff combinations (520 users x 6), which were run through Gridcog to develop resulting powerflow and revenue flow traces for each tariff scenario.

The outputs from Gridcog for each tariff scenario were then combined to represent a total load trace representing the aggregate charge and discharge patterns of the 520 users exposed to that tariff arrangement. This was then scaled (x 2.17) to represent the equivalent of 10% of

114 www.gridcog.com (accessed 7/12/2023).

residences in the Metford area (1128 customers). A figure of 10% was considered an ambitious but achievable benchmark for future V2G penetration in the 2030's.[115]

The aggregate load traces for each tariff scenario were applied to the Metford substation load profile for the selected week to produce a net result. This represents an estimate of the resulting substation profile under a given tariff scenario if 10% of residences had price responsive V2G.

Note that solar exports are not included any of the V2G export results or used to calculate the net substation load profiles.

Each customer week scenario commences with a different EV battery SoC. This is because of the modelling set-up, which operates the case study week on a cycle (the end of the week SoC establishes the starting conditions for the next week). This might reflect real world conditions, should the case study week be similar to the preceding week. Adjusting for this would increase the overall benefits (*and* reduce costs) of spot pass-through pricing scenarios (4-5), which suffer from low start-of-week SoCs, compared to energy ToU pricing scenarios (1-3).

115 Actual uptake of V2G will be driven by a range of factors that are beyond the scope of this study to investigate.

9.2. Scenario 1 (s1) powerflow results – Unidirectional ToU network + ToU energy

Key results:

- 0.6 MW (1.48%) peak demand reduction
- 535 kW reduction in minimum demand (i.e., it's slightly worse)
- Network load factor improvement of 3.61% for the week (weekly LF = 0.398)
- Maximum fleet peak charge of 2.9 kW/EV
- Maximum fleet peak discharge of 1.65 kW/EV
- $29.41 in total average costs per customer for the week (very high)

Figure 10 shows the charge/discharge behaviour at a fleet level over the case study week and the resulting fleet state of charge. The regular ToU tariff schedule drives equally regular battery cycling. This cycling also reflects is the reduction in SoC associated with daily travel, with all recharging happening at home.

The daily travel demand of 5.2 kWh is matched by 2.65 kWh of daily EV imports for retail arbitrage purposes. The extent to which the output from a consumer's own rooftop solar PV is consumed within the home varies by user and across the fleet. Charging predominantly occurs between the retail off-peak window of 10PM to 7AM. Almost all non-travel battery discharging is associated with the objective of offsetting their household import price exposures during the evening peak period, with minimal (EV exports to the grid.

While the retail price incentive for reducing import during system peaks is desirable, the operation of V2G under these tariff arrangements create several perverse outcomes from a grid management perspective. Particularly, high retail import prices during the day provides an incentive to discharge even when electricity supply from the grid may be low of below zero cost (in both wholesale energy and grid terms). The retail FiT rate of $0.07/kWh reinforces this inefficient behaviour by providing a flat rate for exports regardless of local grid or energy market conditions.

The fleet started the week with an average 58% SoC and the average remained in the 45-75% range. Given that users' minimum SoC preference was globally set at 40%, on Tuesday evening there was just less than 5% SoC available for self-consumption or export purposes. The lowest SoC reached by customers was on the evening of the 7th and 8th at 45%.

Figure 11 shows the change in substation load under the Origin Go tariff (incorporating Ausgrid's EA25 ToU network tariff). It shows a small 'incidental' discharge from the fleet of V2G vehicles during critical network peak periods for self-consumption.

The critical network peak at 6PM on the Monday evening is reduced by 0.6 MW (1.48%).

Overall, having V2G on standard retail and network ToU pricing does not materially mitigate local network critical peak demand. The principal barriers to more efficient V2G operation appear to be flat rates for exports (FiTs), and insufficient incentives to reduce peak demand by exporting to the grid at critical peak times.

Figure 10 – Charge and discharge cycling for EVs **for scenario 1** (Metford, Mon 6 – Sun 12 March 2023)

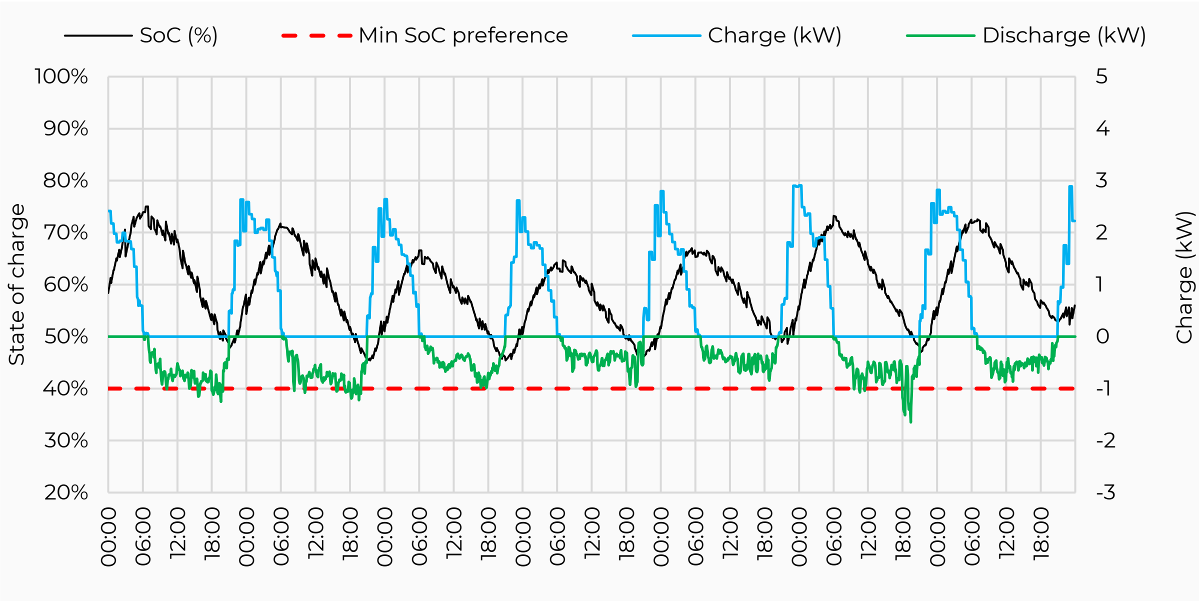
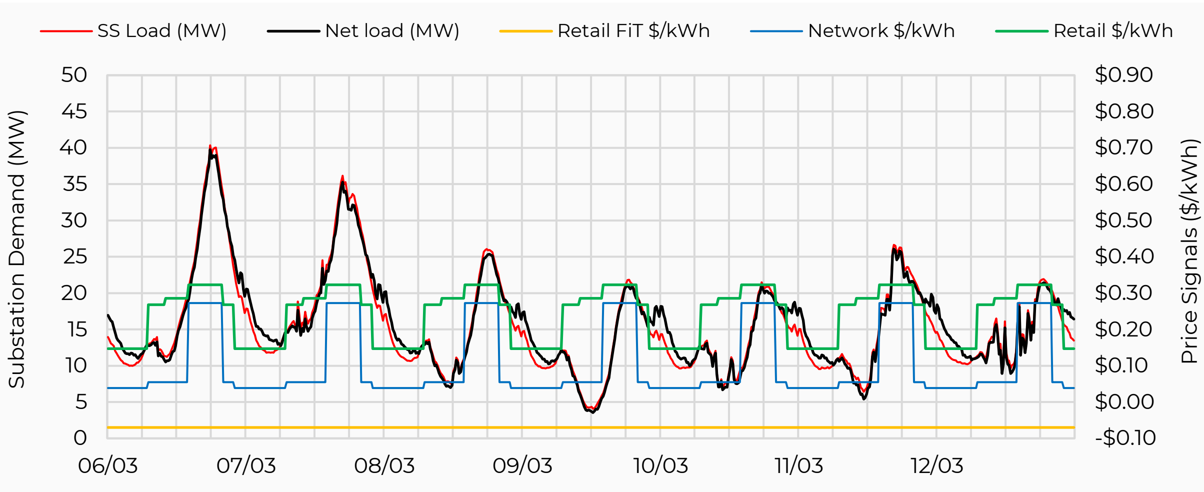


Figure 11 – Price signals and their impact on V2G operation on substation load under **scenario 1** (Metford substation (SS), Mon 6 – Sun 12 March 2023)



9.3. Scenario 2 (s2) powerflow results – Bidirectional Tou network + ToU energy

Key results:

- 0.9 MW (2.23%) peak demand reduction
- -479 kW reduction in minimum demand (i.e. it's slightly worse)
- Network load factor improvement of 4.44% for the week (weekly LF = 0.401)
- Maximum fleet peak charge of 3.45 kW/EV
- Maximum fleet peak discharge of 1.9 kW/EV
- $29.86 in total average costs per customer for the week (most expensive)

Figure 12 shows the charge/discharge behaviour at a fleet level over the case study week and the resulting fleet state of charge. As with s1, the regular ToU tariff schedule drives equally regular battery cycling.

The daily travel demand of 5.2 kWh is matched by 2.74 kWh of daily EV imports for arbitrage purposes (slightly higher than s1). While this includes some solar self-consumption, charging predominantly occurs between the retail off-peak window of 10PM to 7AM. Almost all non-travel battery discharging is associated with offsetting the households retail import price exposures during the evening peak period, with minimal EV exports to the grid.

s2 introduces time-based export and curtailment incentives (EA029) with a cost for exporting of $0.012/kWh in the middle of the day and an incentive to export of $0.023/kWh during the evening peak. This appears to have only a minor effect of V2G operation. As with s1, high retail import prices and the retail FiT rate of $0.07/kWh provides an incentive for the EV to discharge even when the network export charge applies.

Aggregate demand from the fleet peaked at 3.5. kW per vehicle around midnight Friday evening (20% higher than s1). Discharge peaked at 1.9 kW at 7.25 PM on Saturday evening, coinciding with a peak in customer load (sunset was around 7:20 PM) on that day.

The fleet started the week with an average 56% SoC and the weekly SoC range is similar to s1. The lowest SoC reached by customers was on the evening of the 7th and 8th at 45%.

Figure 13 shows the change in substation load under the s2 reflecting a small discharge from the fleet of V2G vehicles during peak period associated mainly with self-consumption, rather exports to the grid. As with s1, EV discharge mainly occurs through the day and into the early evening, with recharging occurring overnight. The critical network peak at 6PM on the Monday evening is reduced by 0.9 MW (2.25%).

Overall, while Ausgrid's bidirectional network tariff (EA025 + EA029) produces more grid friendly V2G operation than under s1, the price signals are not sufficient to substantially offset high retail incentives to discharge even when electricity supply from the grid may be low or below zero. The retail FiT reinforces this behaviour providing a flat rate for exports regardless of local grid or energy market conditions.

Figure 12 – Charge and discharge cycling for EVs for **scenario 2** (Metford, Mon 6 – Sun 12 March 2023)

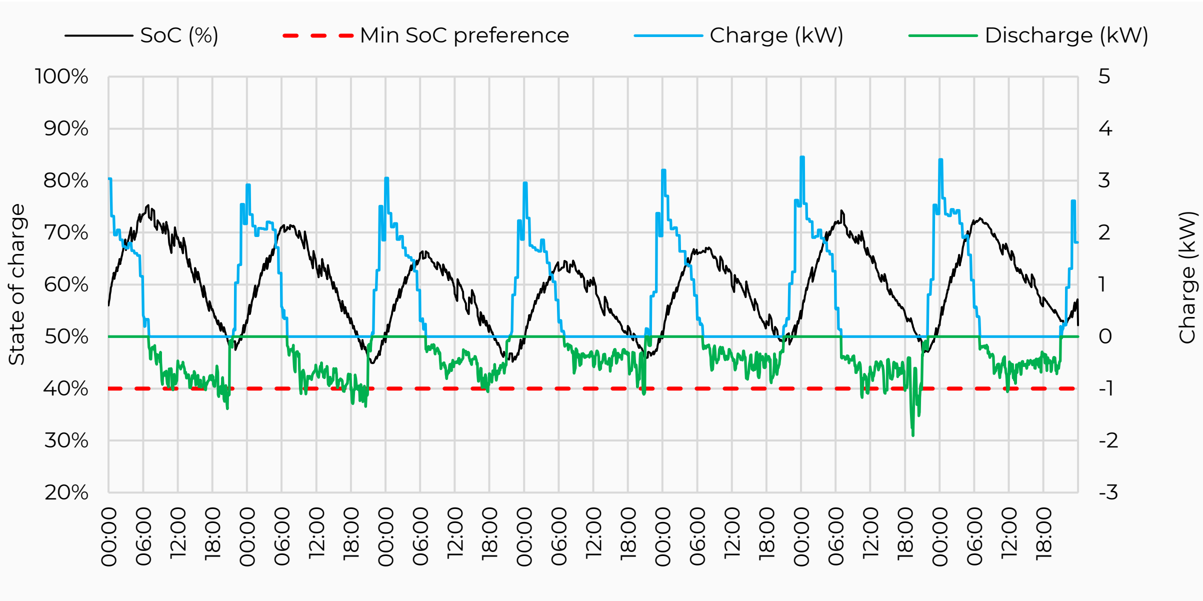
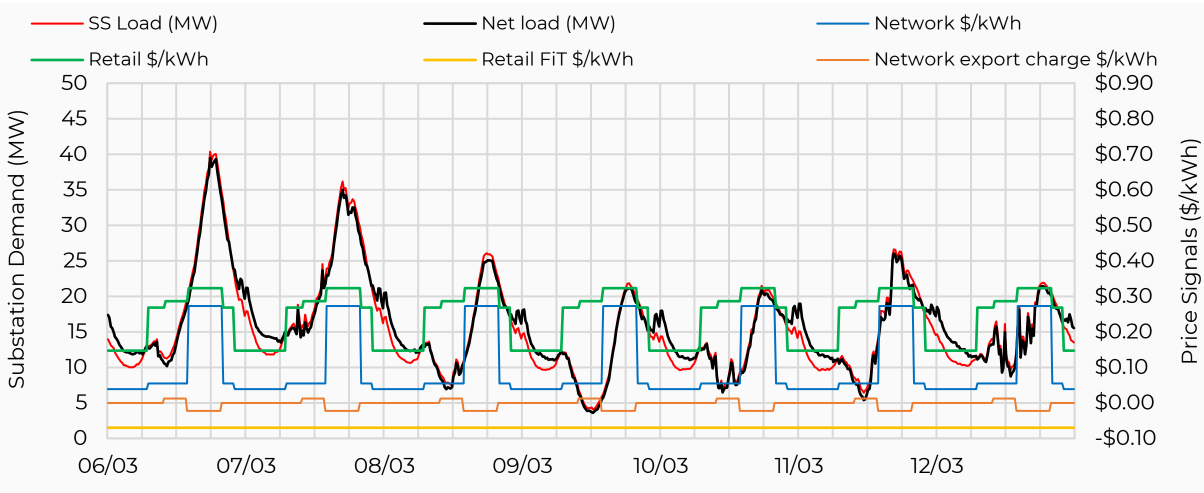


Figure 13 – Price signals and their impact on V2G operation on substation load under **scenario 2** (Metford substation (SS), Mon 6 – Sun 12 March 2023)



9.4. Scenario 3 (s3) powerflow results – Dynamic network + ToU energy

Key results:

- 2.54 MW (6.29%) peak demand reduction (highest, equal with s6)
- -449 kW reduction in minimum demand (i.e. it's slightly worse)
- Network load factor improvement of 4.44% for the week (weekly LF = 0.419)
- Maximum fleet peak charge of 3.6 kW/EV
- Maximum fleet peak discharge of 2.88 kW/EV
- $10.58 in total average costs per customer for the week (mid-range)

s3 introduces a symmetrical critical-peak (dynamic) financial incentive of up to $1.20/kWh (max) which applies on relevant days. This has a significant observable effect of V2G operation with high exports at peak times, and significant pre-charging in anticipation of those peaks.

Figure 12 shows the charge/discharge behaviour at a fleet level over the case study week and the resulting fleet SoC. As with s1 & s2, the regular retail ToU tariff schedule drives roughly regular battery cycling.

The daily travel demand of 5.2 kWh is matched by 3.26 kWh of daily imports associated with V2G export operation (slightly higher that s1 and the highest of all the scenarios. While this includes some solar self-consumption, charging still predominantly occurs between the retail off-peak window of 10PM to 6AM. There is a significant increase in exports to the grid aligned with the weeks' critical peak events.

The fleet started the week with an average 64% SoC (the highest of any scenario) and the SoC range increased to 45-90% as EVs pre-charged to ensure they could take advantage of the network incentive while meeting their minimum SoC preference of 40% (after daily travel). As with all other scenarios, at times during the week there was minimal stored electricity available for self-consumption or export purposes. The lowest SoC reached by customers was on the evening of the 7th at 43%.

As with s1 & s2, high retail import prices during the day continued to provide an incentive for the EV to discharge during solar hours. The retail FiT rate of $0.07/kWh reinforces this behaviour providing a flat rate for exports regardless of local grid or energy market conditions.

In s3 however, the dynamic network tariff provided a much greater incentive to self-consume and export during the critical peak. This is the first scenario where we can say that V2G provided (and was directly renumerated for) services to the grid.

Aggregate demand from the fleet peaked at 3.6. kW per vehicle around midnight on the Sunday morning (slightly higher than s2). Discharge peaked at 2.88 kW between 6 PM and 6:25 PM, on the Tuesday evening coinciding with the network demand peak on that day principally as the fleet entered that day with a higher SoC and so has more capacity to offer.

Figure 13 shows the change in substation load under the s2 and a material reduction in network critical peak demand on the Monday, Tuesday and Saturday when the dynamic pricing applied. The critical network peak at 6PM on the Monday evening is reduced by 2.54 MW (6.29%). Overall, the dynamic tariff arrangement produces a significantly more grid friendly V2G operation than under s1 or s2, strongly reinforcing peak retail import and export tariff rates in the evening. On the other hand, the retail FiT works to temper this outcome providing a flat rate for exports throughout the day, resulting in discharges during the day that could have been economically reserved to assist with network peak demand mitigation.

Figure 14 – Charge and discharge cycling for EVs for **scenario 3** (Metford, Mon 6 – Sun 12 March 2023)

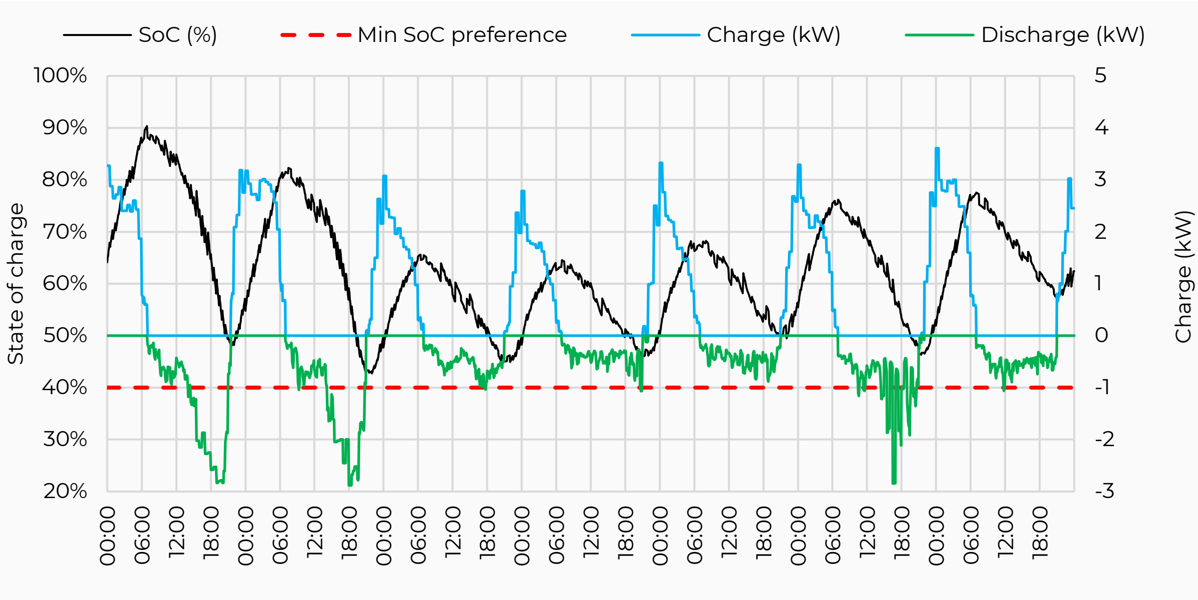
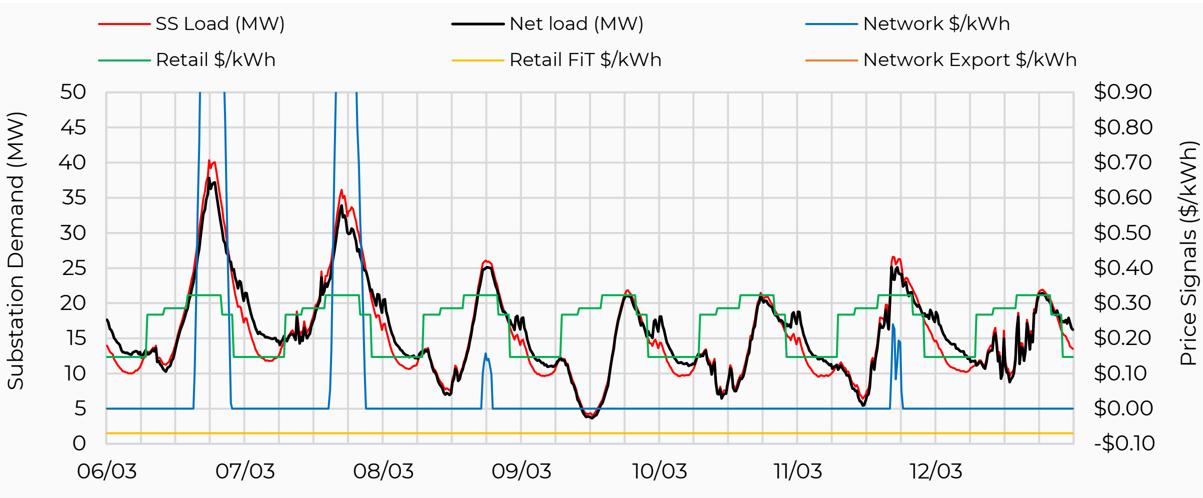


Figure 15 – Price signals and their impact on V2G operation on substation load under **scenario 3** (Metford substation (SS), Mon 6 – Sun 12 March 2023)



9.5. Scenario 4 (s4) powerflow results – Unidirectional ToU network + Spot energy

Key results:

- 1.93 MW (4.77%) peak demand reduction (mid-range)
- 290 kW reduction in minimum demand (i.e. it's slightly better)
- Network load factor improvement of 7.06% for the week (weekly LF = 0.411)
- Maximum fleet peak charge of 2.53 kW/EV
- Maximum fleet peak discharge of 4.01 kW/EV
- $17.78 in total average costs per customer for the week (mid-range)

s4 introduces an energy spot price exposure, which substantially changes the operation of V2G compared to the ToU energy pricing applied in s1-s3. s4 applies a simple unidirectional ToU network tariff (EA25) as per s1.

Figure 16 show the charge/discharge behaviour at a fleet level over the week and the resulting fleet state of charge. Unlike previous scenarios, the spot price exposure drives relatively irregular EV battery cycling. This cycling also reflects the reduction in SoC associated with daily travel, with all recharging happening at home.

The daily travel demand of 5.2 kWh is matched by 2 kWh of daily EV imports for spot market arbitrage purposes. This is the lowest energy imports of any scenario. While this includes some solar self-consumption, charging occurs irregularly both overnight and during the day, reflecting prevailing and forecast spot market conditions.

Scenarios 4-5 commence the week with a SoC of 40% and this impacts its ability to provide arbitrage over the course of the week, and a lower SoC range of 40-70%. Adjusting to an equivalent period start SoC as scenarios 1-3 would be expected increase charge flexibility, reducing costs and increasing revenue opportunities (see *modelling approach* on page 50). The lowest SoC reached by customers was on the evening of the 12th at 40%.

Aggregate peak demand from the fleet averaged at 4.01 kW per vehicle around 5 AM on the Friday morning, while discharge capacity peaked at 2.54 kW around 6:05 PM on the Monday evening, aligning with the network critical peak.

Figure 17 shows a strong incidental alignment between high spot market pricing and local network peaks over the course of the week, and a 1.93 MW (4.77%) reduction in peak substation load (which is mid-range among the scenarios). This indicates that spot market signals, generally supportive, may not be sufficient to achieve grid-optimal V2G operation. There is also no guarantee that spot market pricing will be high when local network demand peaks (see *Ensuring a firm response, market floor price consideration*, p.40). This is risk is not valued in our modelling results and is an important focus for future research.

Network minimum demand (midday Thursday) is unaffected– the EV battery fleet is generally oscillating between moderate charge and moderate discharge over that period in response to behind-the-meter solar soaking and spot market incentives.

Figure 16 – Charge and discharge cycling for EVs for **scenario 4** (Metford, Mon 6 – Sun 12 March 2023)

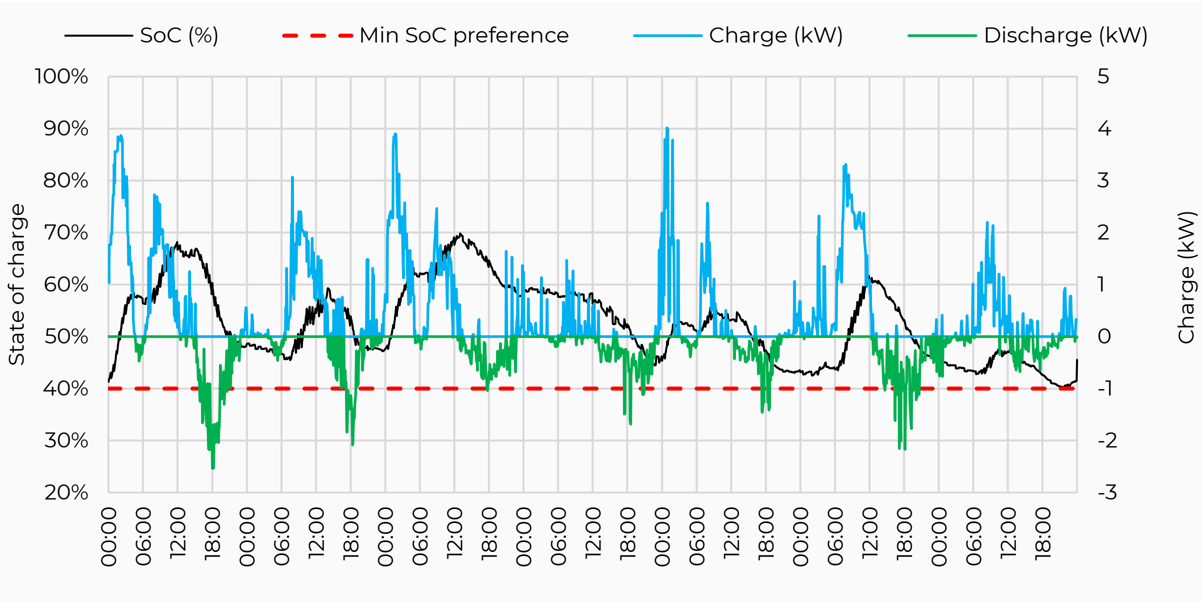
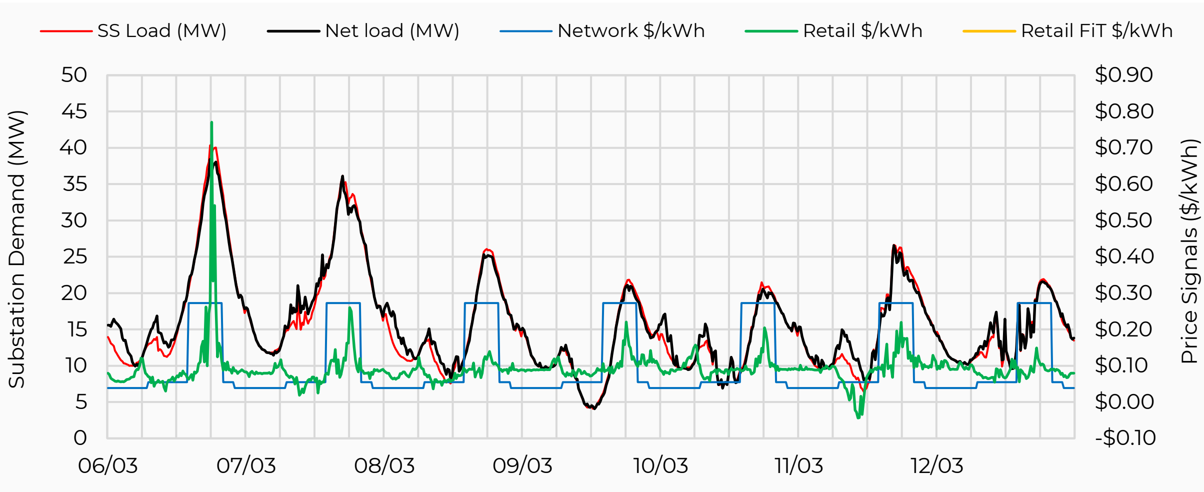


Figure 17 – Price signals and their impact on V2G operation on substation load under **scenario 4** (Metford substation (SS), Mon 6 – Sun 12 March 2023)



9.6. Scenario 5 (s5) powerflow results – Bidirectional ToU network + Spot energy

Key results:

- 2.11 MW (5.24%) peak demand reduction (mid-range)
- 325 kW reduction in minimum demand (i.e. it's slightly better)
- Network load factor improvement of 5.24% for the week (weekly LF = 0.413)
- Maximum fleet peak charge of 4.36 kW/EV
- Maximum fleet peak discharge of 3.59 kW/EV
- 17.73 in total average costs per customer for the week (mid-range)

s5 combines an energy spot price exposure with a bidirectional network tariff that charges for exports during the day, and rewards exports in the evening. As shown in s2, these curtailment and export incentives appear insufficient to make a large difference to overall V2G operation (compare s5 with s4) although the change is generally positive.

Figure 18 show the charge/discharge behaviour at a fleet level over the week and the resulting fleet SoC. It shows peak charging occurs just after 12 AM Friday morning at a higher rate than s4. Peak discharging occurs on Saturday evening rather than during the Monday critical network peak event. This is the result of similarly supportive energy and network pricing, combined with a larger number of vehicles being plugged in and available to take advantage of the arbitrage opportunity.

The daily travel demand of 5.2 kWh is matched by 2.11 kWh of daily EV imports for arbitrage purposes. Charging includes some solar self-consumption and a high proportion of grid imports during both solar hours and overnight.

Despite the operation of Ausgrid's export curtailment charge, network minimum demand (midday Thursday) is unaffected– the EV battery fleet is generally oscillating between moderate charging and moderate discharge over that period in response to BTM solar soaking and spot market incentives.

The fleet remained in a 40-70%% state of charge range over the week, slightly higher than s4. The lowest SoC reached by customers was on the evening of the 12th at 40%.

Figure 19 shows a strong alignment between high spot market pricing and local network peaks over the course of the week, and a 2.11 MW (5.24%) reduction in peak substation load for this scenario.

Overall, the spot price is doing the heavy lifting in promoting exports at grid-friendly times, rather than the network export incentives. While relying on the spot market to reduce peak demand may be initially attractive from a network revenue perspective, it runs the risk of underperformance when high spot prices do not align with network peaks. Ausgrid's export curtailment and export incentives (EA029) would be easily overshadowed by moderately countervailing spot market price (see *Dynamic pricing methodology*, p.40)

Figure 18 – Charge and discharge cycling for EVs for **scenario 5** (Metford, Mon 6 – Sun 12 March 2023)

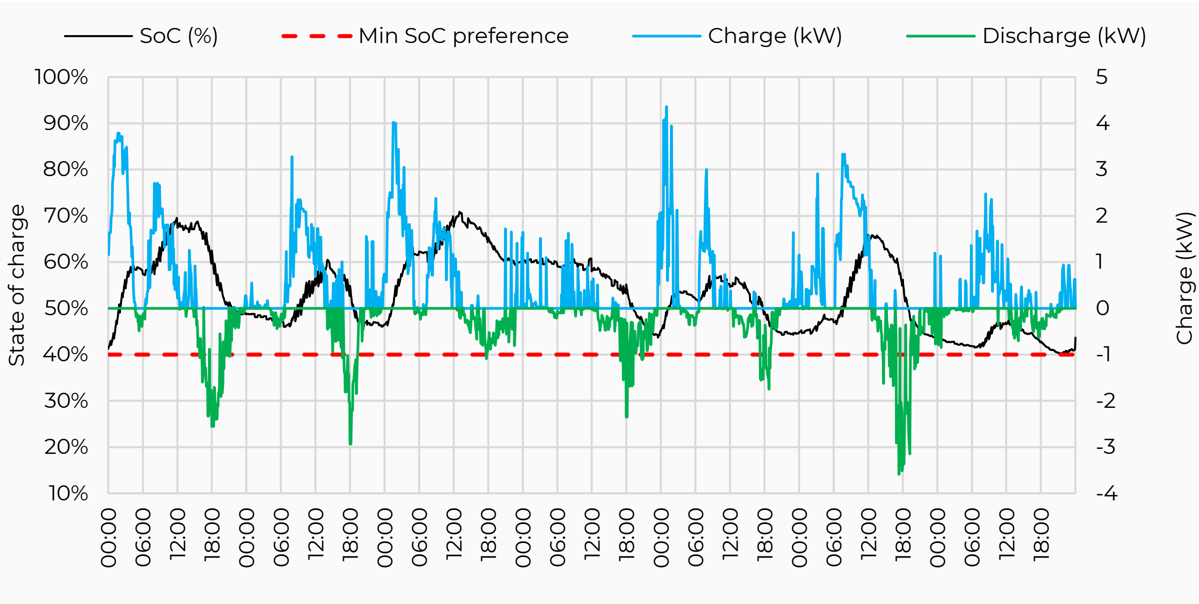
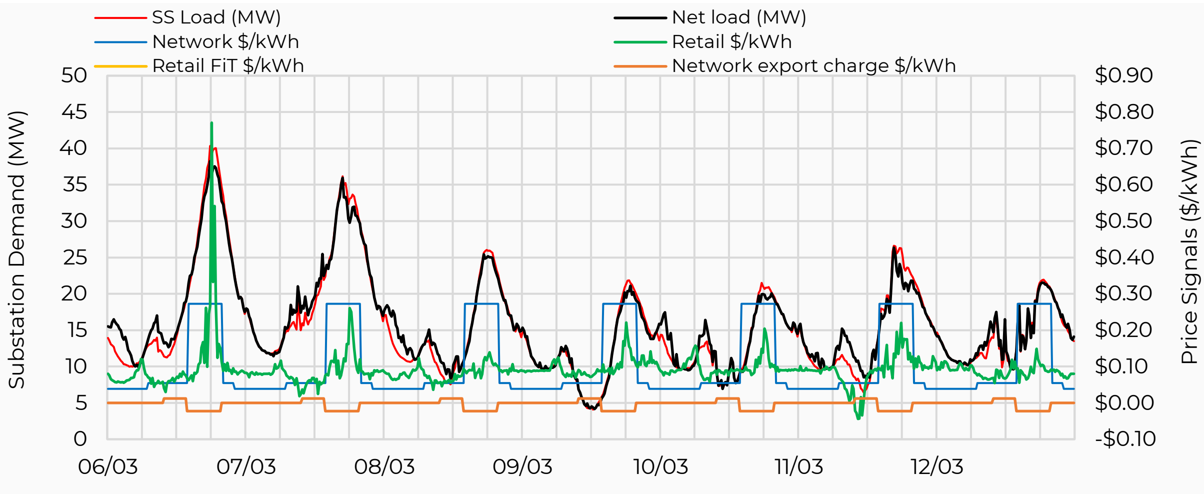


Figure 19 – Price signals and their impact on V2G operation on substation load under **scenario 5** (Metford substation (SS), Mon 6 – Sun 12 March 2023)



9.7. Scenario 6 (s6) powerflow results – Dynamic network + Spot energy

Key results:

- 2.54 MW (6.29%) peak demand reduction (highest, equal with s3)
- 754 kW increase in minimum demand (i.e. it's slightly better)
- Network load factor improvement of 9.04% for the week (weekly LF = 0.419)
- Maximum fleet peak charge of 3.92 kW/EV
- Maximum fleet peak discharge of 4.21 kW/EV
- -$5.54 in total average costs per customer for the week (the best result)

S6 combines an energy spot price exposure with a dynamic, symmetrical tariff that provides a strong incentive to reduce demand and export during critical peak periods. These incentives combine to drive a relatively irregular charge and discharge cycle strongly influenced by electricity market and grid conditions.

Figure 20 shows the charge/discharge behaviour at a fleet level over the week and the resulting fleet state of charge. It shows peak charging occurs around midday on Monday ahead of the critical network peak that evening. Like s5, peak discharging occurs on Saturday evening due to high dynamic network and wholesale prices, combined and a larger number of vehicles being plugged in and available to take advantage of these conditions.

Over the course of the week, the fleet has a wide SoC range of 40-85% with notable pre-charging ahead of network and wholesale market price events. The daily travel demand of 5.2 kWh is matched by 2.54 kWh of daily EV imports for arbitrage purposes. Charging includes solar self-consumption and a high proportion of grid imports during solar hours and overnight.

The lowest SoC reached by customers was on the evening of the 12^{th} at 40%.

Figure 21 shows a strong alignment between high spot market pricing and local network peaks over the course of the week, and a 2.54 MW (6.29%) reduction in peak substation load. This is the same a s3 suggesting that the dynamic network price is able to deliver peak demand reductions independent of energy pricing (i.e., ToU or spot).

Network minimum demand (midday Thursday) is moderately (400kW) higher with the EV battery fleet generally oscillating between moderate charging and neutral over that period.

In s3 and s6 (both dynamic network pricing) there is no network charge outside of critical peak periods. In s6 this means there is no 'friction' in wholesale market trade, increasing revenue opportunities for customers. The EV battery fleet in s6 had the second highest throughput behind s3 but produced the most lucrative results for customer with $5.54 total weekly earnings. This compares to s3, as the second most lucrative scenario, where the customer paid $10.58 in the case study week.

Figure 20 – Charge and discharge cycling for EVs for **scenario 6** (Metford, Mon 6 – Sun 12 March 2023)

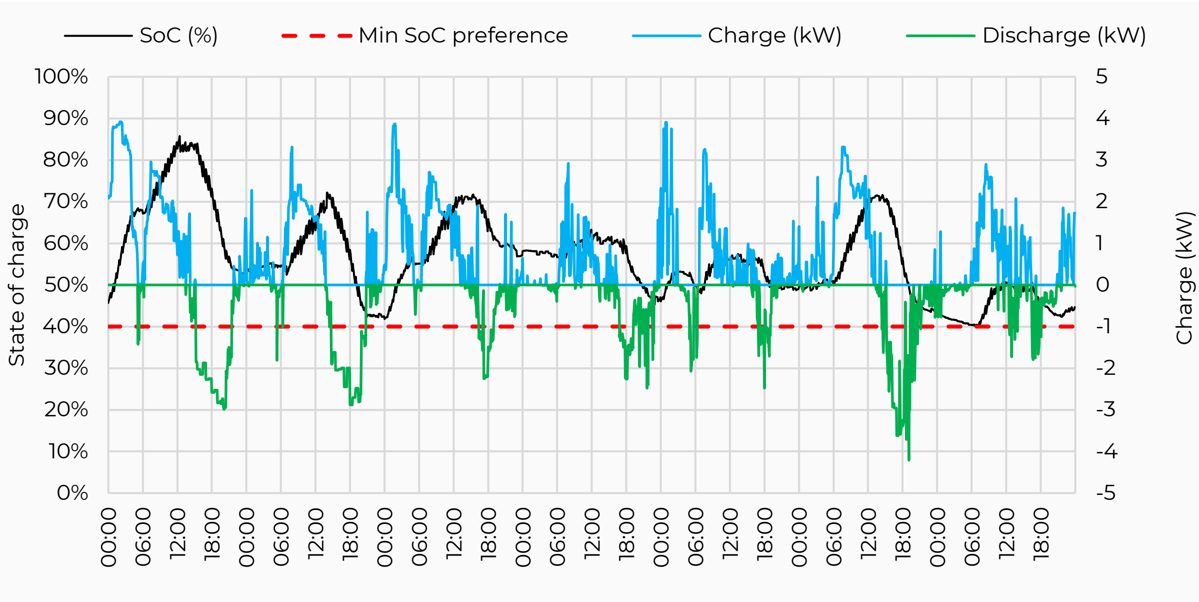
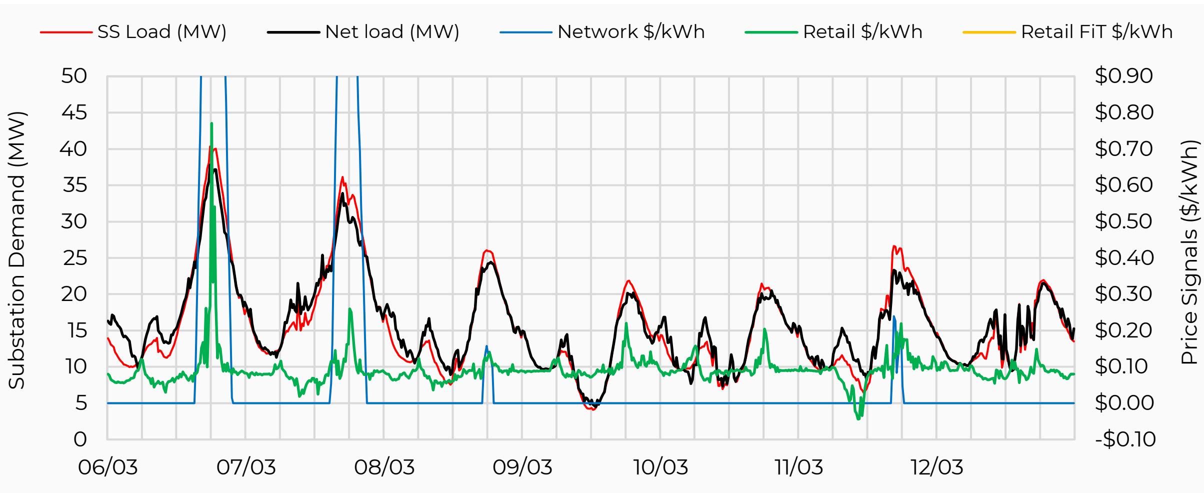


Figure 21 – Price signals and their impact on V2G operation on substation load under **scenario 6** (Metford substation (SS), Mon 6 – Sun 12 March 2023)



9.8. Summary of key powerflow modelling results

Figure 22 provides a summary of the key metrics for each of the tariff and pricing scenarios. The combination of dynamic network pricing and spot market exposure made s6 the most technically benenficial for the grid and financially beneficial to customers *in the case study week*.

The next section of this report will explore revenue flows over a longer timeseries and compare selected scenarios against the LRMC revenue test to establish whether, for example, s6 is economically efficiency and financially sustainable for a network to offer.

Figure 22 – Summary of key metrics in the case study week for each tariff combination

	s1 Network Uni + ToU Energy	s2 Network Bidi + ToU Energy	s3 Network Dyn + ToU Energy	s4 Network Uni + Spot Energy	s5 Network Bidi + Spot Energy	s6 Network Dyn + Spot Energy
Total EV Exports/ Customer (kWh)	55.80	58.73	76.07	33.20	40.39	64.27
EV Total Imports/ Customer (kWh)	103.66	107.42	127.60	78.20	86.42	114.68
V2G charge kWh/ EV/day	2.65	2.74	3.26	2.00	2.21	2.93
Critical Peak Reduction (MW)	0.60	0.90	2.54	1.93	2.11	2.54
Critical Peak Reduction (%)	1.48%	2.23%	6.29%	4.77%	5.24%	6.29%
Load Factor	0.398	0.401	0.419	0.411	0.413	0.419
Load factor improvement	3.61%	4.44%	9.10%	7.06%	7.64%	9.04%
Net Total Costs/ Customer ($)	$29.41	$29.85	$10.58	$17.78	$17.73	-$4.54

The correlation between peak demand reduction and customer benefit is illustrated in **Figure 23** reflecting that *the extent that customers will provide export services to mitigate network peak demand is largely proportional to the benefits of them doing so*. This is a function of the V2G optimisation model we have used rather than a reflection on human behavior.

Optimisation solely is based on maximising financial benenfits to customers within given constaints rather than other factors such as social or environmental values.

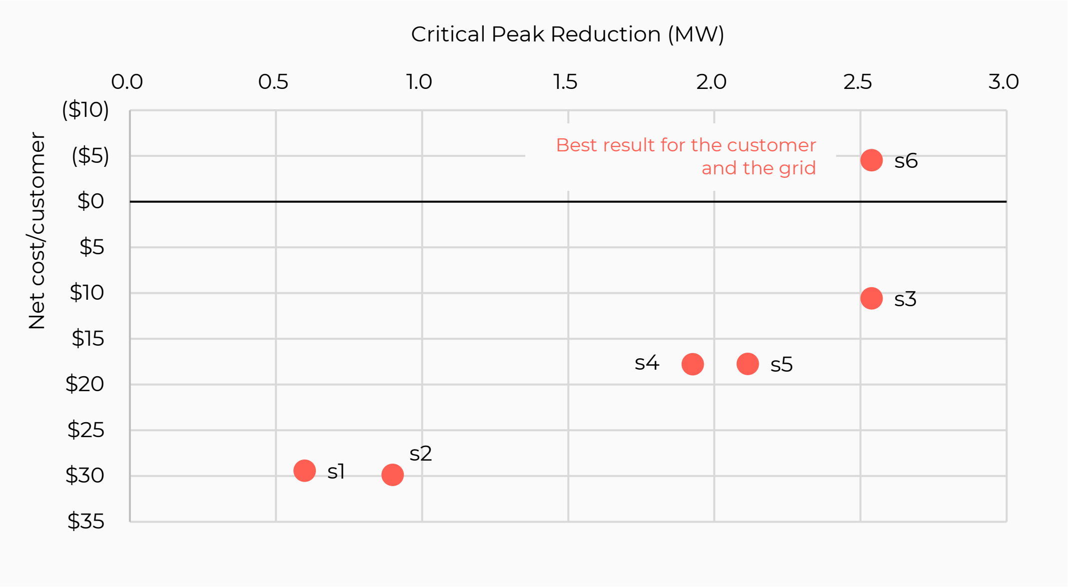


Figure 24 – Average network, retail and net costs by customer in the case study week. Negative costs indicate net customer revenues.

shows that network revenues (customer network costs) remain similar across the scenarios, except for the two dynamic export scenarios where the network would make a net payment to the customer in the case study week.

The net value to customers in both charts is also influenced by the energy (retail or spot) value of the providing the service. This is illustrated in the large difference in net customer in s3 vs s6. The results indicate a substantial premium for customer for retail (s1-3) pricing compared to wholesale (s4-6) energy costs and a slight reduction in energy costs associated with s6 and highlights the energy marlet participation benenfits of dynamic (critical peak).

Our dynamic pricing model applies variable charges only during critical peak (or critical minimum demand periods. The modelling results indicate this improves energy market earnings as evidenced by the small reduction in energy costs in s6 comapred to s3 and s5, **Figure 24**)

Figure 23 – The relationship between critical peak demand and the sum (net) of energy and network outcomes in the case study week. Spot energy costs include Amber subscription and passed-through regulatory and fees.

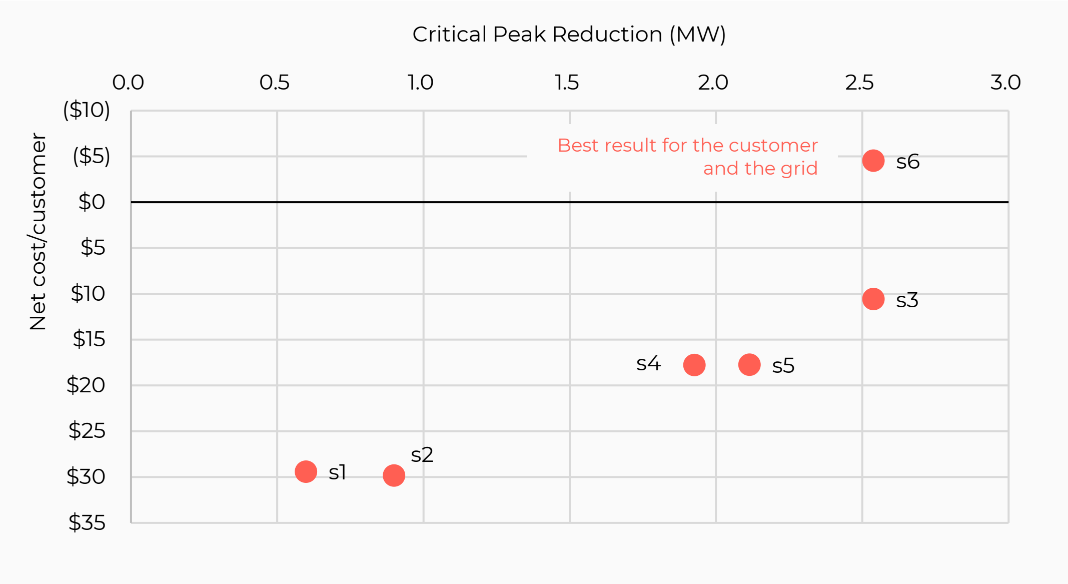
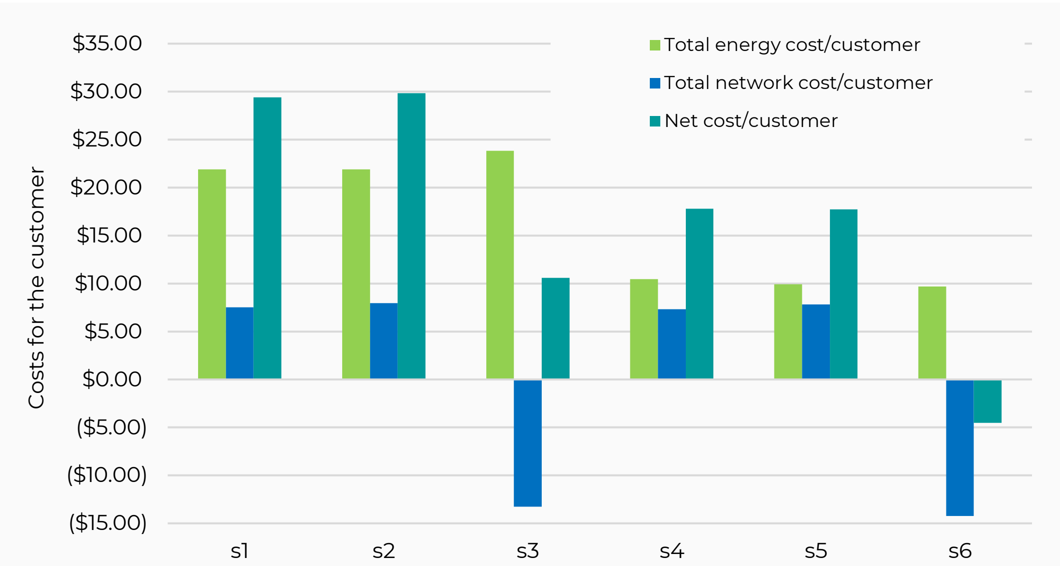


Figure 24 – Average network, retail and net costs by customer in the case study week. Negative costs indicate net customer revenues.



10. Cashflow analysis method and results

The outcomes of the powerflow analysis highlighted the different in the relative performance of alternative tariff and pricing structures in mitigating peak demand. These results were used to shortlist scenarios 2, 3, 5 & 6 for an analysis of cashflows.

The purpose of the cashflow analysis is to address to questions:

1. **What are the annualised financial costs and benefits to customers under the four selected scenarios?** This informs the likelihood of the pricing arrangements having retailer and/or customer appeal.
2. **What are the long run costs and benefits to the network?** This informs an assessment of whether the tariff is efficient and consistent with the NER pricing principles.

10.1. Approach to cashflow analysis

The cashflow analysis was conducted using the economy, sponge and commuter load profiles to ensure a diverse range of residential user types[116] Solar system size was standardised across the users at 7kW which is the current average in the Metford area[117]. Each user was assigned a 5-year vehicle availability profile and modelled as both a smart charging user and a V2G user. This resulted in a total of 24 modelling runs in Gridcog modelling platform.

Key modelling parameters are listed in **Table 6** below.

Table 6 – Summary of cashflow modelling parameters

Load profile	Solar	Vehicle availability[118]	Charging mode	Scenarios
Sponge user	7kW (curtailable)	WFH profile	• Smart charging • V2G	2, 3, 5, 6
Commuter user	7kW (curtailable)	Commuter profile	• Smart charging • V2G	2, 3, 5, 6
Economy user	7kW (curtailable)	Blended profile (30/70)	• Smart charging • V2G	2, 3, 5, 6

The annualised 5-year cashflow modelling results are not intended to be statistically representative of the whole population in the Metford area. They are best interpreted as illustrative examples of the range of outcomes under the different V2G implementation scenarios.

116 See section Customer load profiles, p.40 The mega user load profile was excluded to reduce the number modelling runs.

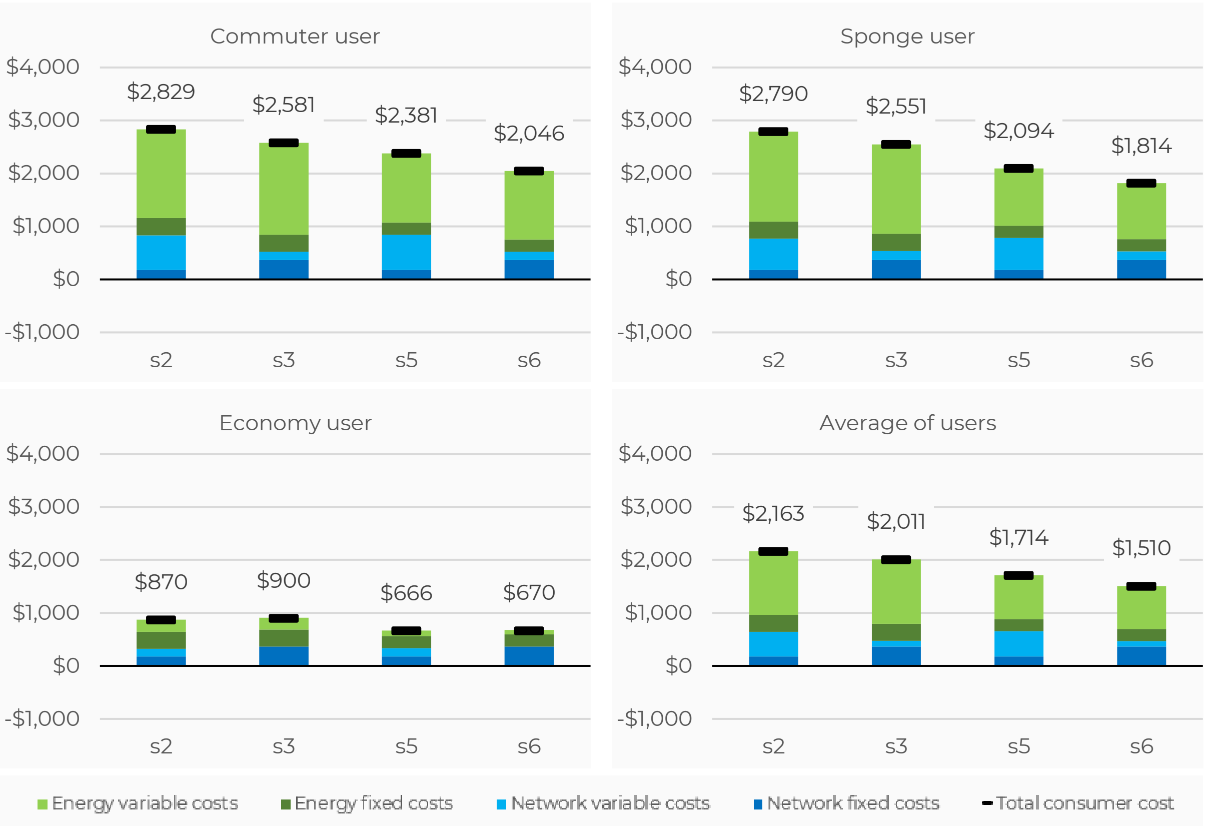
117 See *Solar assumptions*, p.46

118 See Estimating vehicle availability, p.43

10.2. Comparative consumer outcomes for smart charging operation

Smart charging operates to shift EV electricity demand to periods of low pricing. For the purposes of this study, smart charging constitutes a baseline for network powerflows and customer revenue flows, with V2G results largely measured against that. Figure 25 summarises the total annualised electricity costs for three different smart charging user types that differ in relation to their household load profile.[119]

Figure 25 – Breakdown of total annualised customer electricity costs when smart charging under each tariff scenario, by customer type (includes household loads and solar)[120]



Major differences in energy and network costs can be observed between users with the economy user having lower bills across all scenarios related to their lower overall consumption and slight net earnings for network variable charges under s3 & s6. All other network and energy cost items are a net cost to the user on an annualised basis.

Between the scenarios, there is a pattern of lower costs when on a dynamic network tariff (s3 & s6), and lower energy charges when spot exposed (s5 & 6). The exception to this is for the economy user which is best off in s5 due to lower network and energy fixed costs and lower relative savings on variable cost components (compared to other larger energy users).

119 See *Customer load and, solar and EV technology assumptions*, p.39

120 Spot prices are for Oct – Sept 2023. See Appendix B - Details for each modelled tariff, p.75

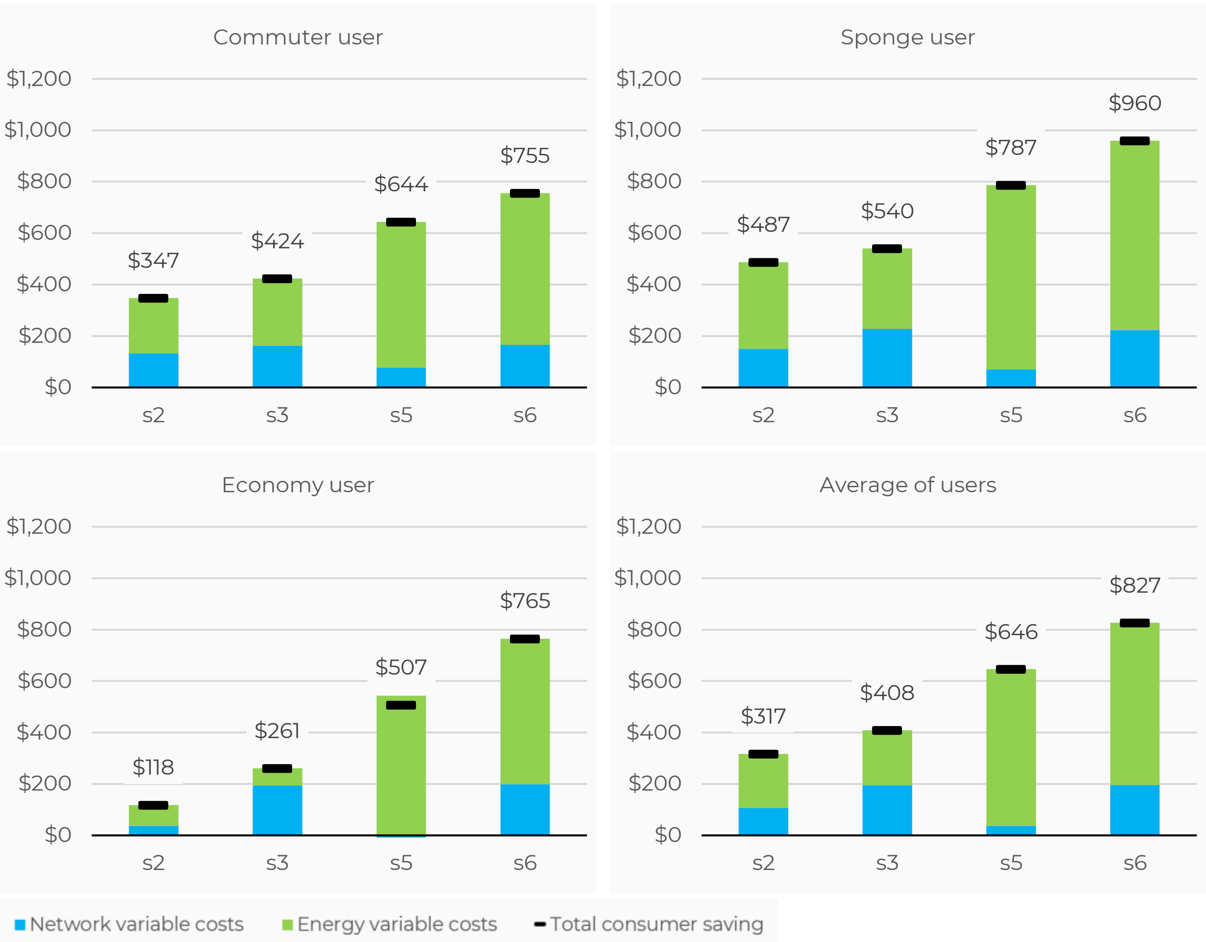
10.3. Comparative consumer outcomes for V2G operation

Compared to smart charging, V2G exports can reduce customer electricity bills by offsetting demand during peak pricing periods and exporting to the grid in exchange for an export incentive.

s2 has a flat rate retail feed-in tariff of and only a modest ToU network incentive to export less during the day and more during the evening. s3 replaces the network incentives with a large bidirectional and symmetrical incentive to reduce demand and export during critical network peak periods which increases the value of V2G. s5 and s6 introduces spot passthrough energy pricing which creates energy arbitrage opportunities for V2G.

Figure 26 summarises the total annualised electricity cost *savings* from V2G by user compared to smart charging. The results demonstrate V2G operation delivering savings in variable energy and network costs for each user, with these being most pronounced for larger users and under spot passthrough arrangements. Variable network cost savings are largest under dynamic pricing (s3 & s6). The economy user has a small increase in network variable costs under s5 (-$37, too small to see in the charts) which is compensated by spot market earnings.

Figure 26 – Reduction in annualised electricity costs in moving from smart charging to V2G under each scenario, by customer type

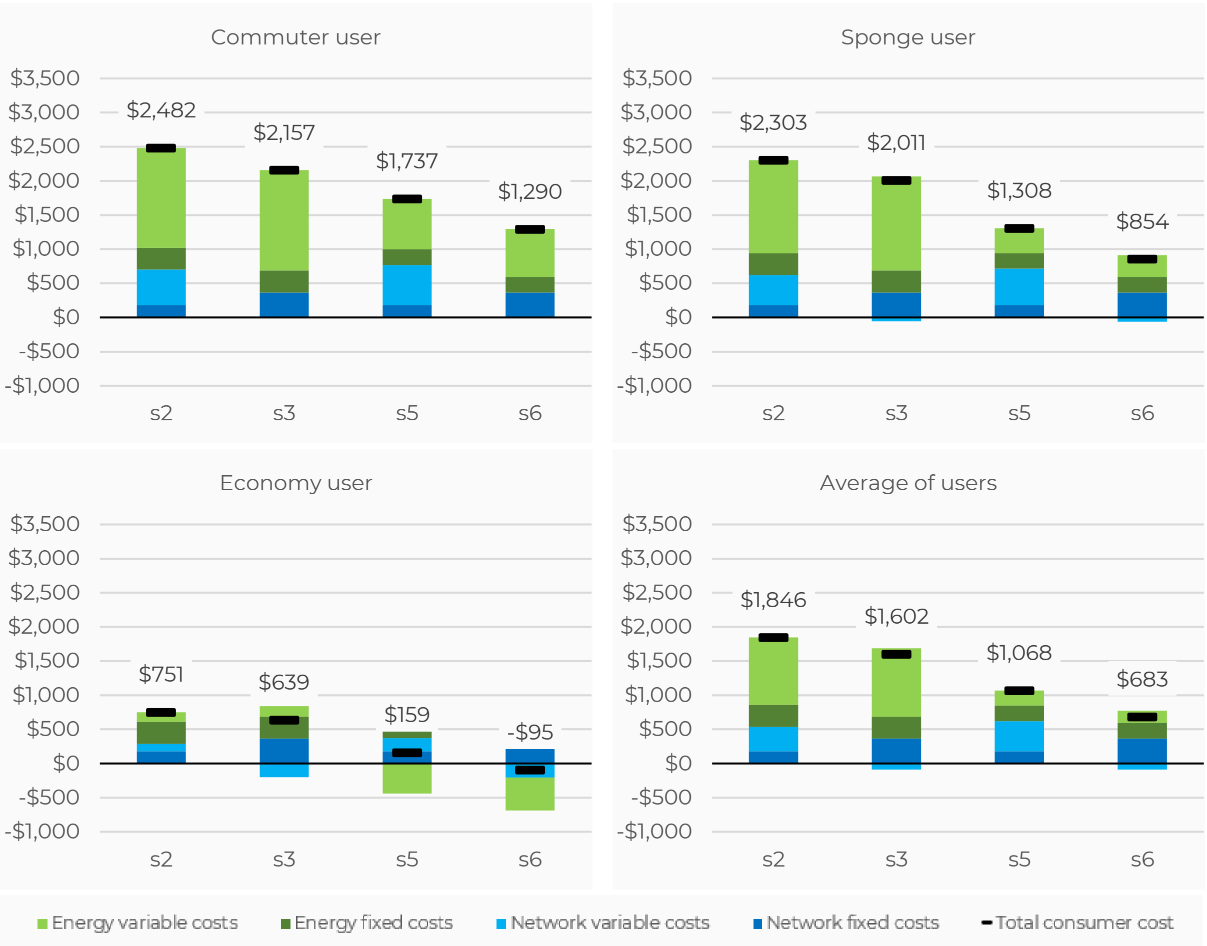


These annualised savings results can be used to calculate the simple payment for each user type under the different tariff scenarios, as shown in Table 7. We have assumed an incremental capital cost of $2500 to install a DC bidirectional charger, compared to a Level 2 (IEC Mode 3) AC smart charger.

Table 7 – Simple payback of V2G compared to smart charging (years) for different customers and under different tariff scenarios[121]

	s2	s3	s5	s6
Eco user	21.2	9.6	4.9	3.3
Commuter user	7.2	5.9	3.9	3.3
Sponge user	5.1	4.6	3.2	2.6

Figure 27 – Breakdown of total annualised customer electricity costs for V2G users under each scenario, by customer type (includes household loads and solar)



This illustrates that the cost effectiveness of V2G varies widely by customer type. Larger users stand to benefit the most, as do customers on more variable and cost reflective energy and

[121] Assumes net capex of $2500, which is the medium-term price expectation of $3500 for a DC bidirectional charger, less $1000 for a standard L2 AC smart charger. See enX (2023) *V2X.au Summary Report Opportunities and Challenges for Bidirectional Charging in Australia*, p 12

network pricing arrangements. s6 offers a return on investment in under four years for all users and is the most customer-beneficial tariff arrangement for all C2G customers.

Total annual electricity costs for each customer are shown in Figure 27. They indicate that network variable costs are eliminated by dynamic tariff arrangements (s3 & s6) across all customers with economy and sponge users achieving net income from the network. These cost reductions are compensation for the operation of V2G which generally discharges (when it can) during critical network peak periods. This constitutes a service to the network and other network users.

Dynamic network pricing is also observed to support reduced customer electricity costs for spot exposed customers. In s6, the customer faces no network variable charges outside of rare critical peak periods. This eliminates transaction costs in electricity market arbitrage allowing the customer to take advantage of smaller arbitrage opportunities that they would otherwise. Variable network costs outside of critical peak or trough periods can be viewed as a tax on trade that delivers no economic benefit to individual customers or network users collectively.

As with the smart charging scenarios, in the dynamic pricing scenarios (s3 & s6) the network recovers its residual costs via fixed daily supply charges, and these are unaffected by V2G operation.

10.4. EV battery throughput and health

As shown in Figure 28 below, the volume of annual imports, exports, solar curtailment and self-consumption does not differ materially between s2 & s3 for any user. This reflects that pricing for exports are driven only by the retail flat FiT and only during solar hours. The dynamic tariff periods under s3 are also not protracted enough to make a significant difference to export volumes.

Battery discharge increase under the spot passthrough scenarios (s5 & s6) reflecting much greater opportunity for energy arbitrage both through self-consumption and export. There is a significant step up in battery operation under s6 where dynamic tariff arrangements because of at least two factors:

1. Increased opportunity to participant in dynamic pricing events, including strategic pre-charging during periods of low spot energy prices.
2. Outside of critical peak times, zero variable network charges apply, and this reduces transactions costs and barriers to spot market participation.

This figure also shows that the operation of DOEs result in some export curtailment.[122] This is related to circumstances where substation minimum demand is assumed to be contributing to LRMCs for the network. Under dynamic tariff arrangements, these prices only apply beyond 1.5kW export per customer.

Figure 28 shows that spot exposed customers (s5 & s6) experience significantly higher battery throughput which is likely to contribute to battery degradation over the long term. Battery

[122] See *Use of Dynamic Operating Envelopes,* p.37

degradation for Lithium-ion batteries is principally a function of charge/discharge rate, battery temperature and SoC, whereby very high and very low SoCs can accelerate degradation.[123]

Figure 28 – Breakdown of total annualised customer electricity import and exports for V2G users under each scenario, by customer type (includes household loads and solar).

While vehicles can generally be assumed to be in a garage or other covered area during V2G operation (i.e. out of extreme temperature conditions, this may not always be the case. We have not accounted battery degradation or for parasitic losses from mechanical battery cooling in our model. While this is not expected to be material, it is worth future investigation.

V2G operation in our modelling scenarios is characterised by moderate charge and discharge rates (7.4 kW peak, consistent with Level 2 typical AC charging limits) and generally moderate SoC ranges.

Figure 29 (below) shows that, for the hardest working battery (sponge user, S6) the EV batteries stayed with a SoC range of 30-80% 90% of the time. This is considered a healthy range where frequent, low charge-rate cycling is expected to have a negligible impact on

[123] Cellsaviors.com (accessed 12/12/2023) *Why Do Lithium Batteries Get Worse Over Time?*. See also this excellent video: *EV Battery Health with Dr Jeff Dahn Dalhousie U (youtube.com)*

battery health. Ultimately, vehicle battery warranty conditions will need be formalised to account for V2G operation and these can be applied as a constraint in future modelling.

User preferences were set to maintain SoC above 40% where possible and this was achieved 98% of the time. Relaxing this limit can be expected to result in greater flexibility for V2G operation and therefor greater savings for customers.

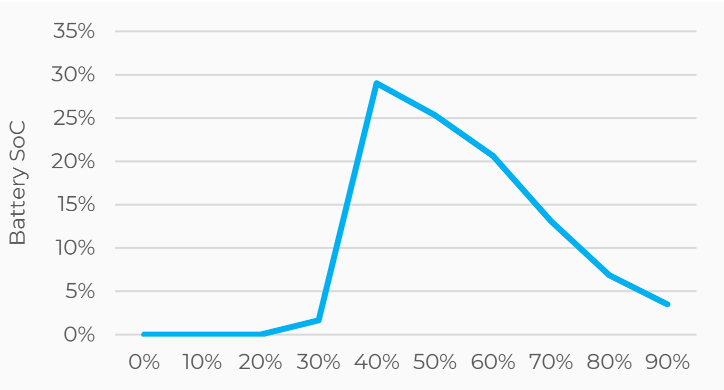


Figure 29 – The percentage of time over the course of 5 years that a battery is at a given state of change (s6, sponge user).

10.5.Testing of cashflow results against network LRMC

Clause 6.18.5(f) of the NER requires tariffs to be based on the long run marginal cost (LRMC) which is an estimate of the cost of the future to supply of one additional unit of network hosting capacity (in kW or kVA) at peak times. In essence, the variable component of a tariff should not recover revenue in excess of a network's LRMC.

LRMCs can be developed for load and generation and for network areas with different load or generation growth characteristics. For this analysis, we have used Ausgrid's LRMC values for its low voltage tariff class of $42.8 per kW (annualised) which applies to its low voltage network in areas of demand growth.[124]

We have interpreted the LRMC requirement as a test whereby **estimated variable charges to customers in a tariff class over a year should not be greater than the annualised LRMC** on a per kW demand reduction basis. This reflects that residual costs are intended to be recovered from fixed daily supply charges and that variable charges are intended to recover only forward looking (avoidable) costs.[125] This means that where a future cost to the network can be confidently avoided, the net variable charges for customers in the relevant network location and tariff class should be zero.

kW demand reduction is measured against the historic peak demand of the Metford substation at 6pm on 6 March 2023 for each scenario (i.e., historic peak demand). Results can

[124] Houston Kemp (2023) Attachment 8.6: Long run marginal cost import methodology report Ausgrid's 2024-29 Regulatory Proposal, p 5.

[125] See *Residual cost setting*, p.41

be seen as indicative of any substation with similar characteristics subjected to the specified modelling conditions, rather the Metford substation specifically, at any point in the future.

Figure 30 shows the range of variable costs to the network for customers under each scenario for different customers. The results for s2 and s5 indicate net cashflows to the network associated with higher variable tariff revenues. These are normalised to account for reduced fixed charges under these scenarios with the average reported as the net of this.[126] This provides a like-for-like comparison of variable charges under the different tariff scenarios after residual costs are equalised.

The results show that the cost of achieving a kW of demand reduction is lower than Ausgrid's LRMC in all cases. Dynamic tariff scenarios s3 and s6 show net payments to the households (excluding daily supply charges) of around $39/kW, and net revenues for the bidirectional network support tariff of $49- $77/kW per annum.

These are all relatively small number indicating no major over or under recovery by the network. Optimally, all households that are contributing to peak demand reduction should receive between zero and $42.80/kW for the peak demand reduction. There is therefore a modest over recovery in S3 and s6.

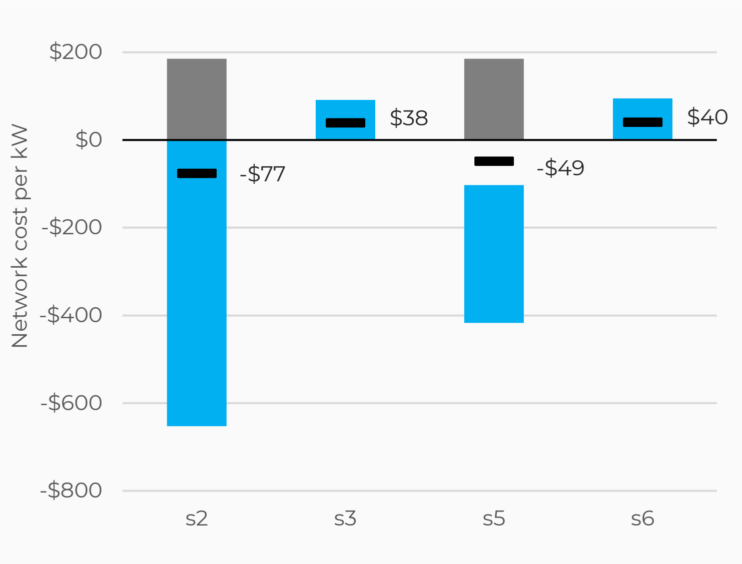


Figure 30 – The range of costs to the network of mitigating peak demand across selected users for each scenario.

The fixed cost normalisation value accounts for the relative under recovery of residual costs through daily supply charges in scenarios s2 and s5.

Negative values indicate net cashflow to the network.

Over time, these variable costs are likely to vary according to number and duration of critical peak events over a year – this will both increase customer costs for load and increase export revenue opportunities. Overall, this would be expected to benefit customers with lower household load at peak times.

This revenue convergence on LRMC is somewhat surprising considering that the dynamic tariff peak pricing ($1.20/kWh) has been set in relation to the spot market floor price (where the opportunity cost of providing network support presents a SRMC for the customer). Preliminary analysis of the modelling results indicates that, in the absence of countervailing incentives, an

[126] daily supply charge in s3 % s6 is $1/day, $365/year. See *Appendix B - Details for each modelled tariff,* p.84 The

incentive payment of $0.50/kWh could be sufficient to ensure a full and firm response from a fleet of V2G resources.

Critical peak pricing could be brought down in several ways, including:

1. An increase in the market floor price – This would result in a firmer demand response outcome being achieved at a lower price to the network (and consumers)
2. Stop loss arrangements for critical peak pricing – In this case the customer on a spot passthrough energy tariff could be *guaranteed* a base price for exports during a critical network peak demand event (e.g., $0.50/kWh) which increases only if the spot market is below a given strike price (e.g., $0). This means the network is only liable to pay more (up to $1.20/kWh) when the spot price is below the strike. Where applied to load, this could substantially reduce consumer price risk exposures.

The application of symmetrical contract-for-difference arrangements, their design, and how they would fit under the NER requirements for network pricing, and worth exploring further.

It is important to note that s3 and s6 deliver substantially more peak reduction than s2, and somewhat more than s5. Further modelling is needed to test whether this indicates a non-linear price relationship between demand reduction and cost of demand reduction. While this would be expected in the field, in this modelling exercise this result could simply be associated with the insurance approach to setting prices under dynamic pricing arrangements.

11. Key findings

Dynamic tariffs are the most beneficial arrangement to support efficient V2G operation.

At 10% penetration, all V2G incentives structures worked to reduce critical network peak demand in the week of 6-12 March 2023. Grid benefits were highest under dynamic tariff and spot price passthrough arrangements which provided incentives for exports during critical peak times.

Dynamic network tariffs delivered the highest rate of peak demand mitigation and the best result for customers. This is because customers were specifically rewarded for reducing network peaks rather than incentives being smeared, as they are under ToU tariff arrangements.

Our price settings for dynamic tariffs were set to ensure that peak demand reduction incentives would prevail regardless of any countervailing spot market incentives that may arise (such as a market floor price (MFP) event). This resulted in the network paying a substantially more to ensure a form response than if the MFP was set at a higher rate. There is no documentation or analysis on why the current market floor price is set at -$1000/MWh and the implications of retaining it at this rate. The results of this study suggest the implications for DER operation and local network operation, should be more fully considered by the AEMC Reliability Panel.

Overall, dynamic tariffs were found to support the following outcomes:

- Firm grid reduction in network critical peak demand at cost less than the estimated LRMC for the Ausgrid LV network
- Reductions in inefficient EV charge discharge and battery cycling (e.g., less discharging during sub-critical periods when it was of more limited value to the grid
- Lower transaction costs for customers outside of network critical peaks resulting in higher returns for spot exposed customers
- Lowest electricity bills for customers

It appears unlikely that bidirectional ToU network tariffs are support efficient outcomes from V2G operation.

Bidirectional ToU network tariffs are mildly preferable to unidirectional tariffs on all measures. Under current tariff pricing they support self-consumption, rather than exports as a grid service, and therefore do not achieve optimal V2G operation.

ToU tariff suffer from a seemingly intractable limitation: In order to offer sufficient incentives to support V2G battery discharge during critical peaks, they must overcompensate discharges throughout the year (or season). This makes them unaffordable to networks and imposes inefficient costs on non-V2G customers. Network support pricing must remain low, and this results in V2G assets not providing service at peak times that would otherwise be of high value.

Networks should continue to experiment with bidirectional ToU pricing structures as they develop and transition to more dynamic pricing arrangements.

Consistent with previous modelling, spot passthrough retail contracts can greatly reduce costs for EV owners with smart charging and V2G.

For customers with flexible, and especially bidirectional resources can move their load and generation around to take advantage of dynamic spot market conditions. Customers with low household demand and use V2G to achieve net earnings (negative bills) through spot arbitrage and by providing network services under dynamic network tariff arrangements.

Dynamic network tariffs amplify the benefits of spot passthrough arrangements by reducing transaction costs (we have assumed zero network variable charges) outside of critical peak periods. This allows for freer trade in the spot market and greater opportunities for spot market arbitrage. These outcomes are contingent on technology that can effectively forecast and manage price-risk exposures.

Field trials are needed to validate these modelling results and to determine, more precisely, the customer and DER technology types that can most benefit under spot passthrough arrangements.

V2G will be a financially attractive proposition to many EV drivers.

While smart charging is itself financially beneficial for many drivers, V2G contributed additional savings of between $118 and $960 across the users and incentive arrangement explored in this study. Most scenarios produced a simple payback on upfront costs of under 7 years. Under spot passthrough arrangements, this dropped to under 4 years. The fastest paybacks were for customers on spot passthrough contracts with dynamic network pricing.

Unfortunately, the households who stand to gain from V2G are likely to be standalone, owner-occupied dwellings. While future commercial and technical innovation may allow apartment dwellers and renters to benefit, in the meantime social equity can be supported by ensuring network pricing remains ‘cost-reflective’ such that the net benefits of V2G spill over to all electricity customers.

Vehicle availability matters.

Some of the largest V2G fleet discharges occurred at 6PM the Saturday afternoon (11 March 2023). While network demand was high at the time, it was not near a critical peak Reasonably favourable spot market conditions prevailed at the time $220/MWh and dynamic network prices were at $230/MWh (19% of the critical peak price). Significant V2Gdischarges were also observed under ToU pricing due to retail and network peak pricing periods.

One of the main reasons that fleet discharges were so high, was simply because there many more vehicles connected at the time: nearly 57% more than during the Monday critical peak demand event.

Large differences in vehicle availability overtime can greatly shape grid outcomes. The vehicle availability model developed for this study seeks to address this issue but there is a need for more data on user plug-in behaviour from a wide sample of users. This could be a focus of knowledge sharing from publicly funded smart charging and V2G trials.

diversity

Secondary peaks can undermine the network value of V2G at high penetrations.

We found that a V2G penetration of 10% can result in discernible secondary local network (outside of the original peak period) due to pre and recovery charging. Secondary peaks are those that have not been forecast by the network operator or factored into pricing. At 20% penetration, these secondary peaks threatened Metford substation capacity limits.

Our model implemented dynamic operating envelopes across all scenarios which effectively mitigated adverse outcome. Alternative approaches include some smoothing of critical peak price incentives to ensure that any rebound in demand occurs during periods of low demand however, this has the potential to dilute efficiencies associated with more targeted incentives.

Further work in needed to explore the circumstances under which secondary peaks could occur, and how they could be effectively mitigated. Outcomes from field trials will be essential in determining instantaneous and intertemporal demand elasticity and models that networks can use to support the use of more targeted incentives that do not undermine broader network operation.

Network tariff reform needs to be accelerated and become more technology aware.

The NEM is moving to a new regulatory environment where tariff decisions should be assessed against not only the pricing principles but their ability to support jurisdictional emissions reduction targets. Additionally, the networks are seeking to incorporate highly price-responsive, automated smart DER technologies that can respond to prices dynamically. This means customers' demand and price elasticity is higher than ever envisaged before.

Innovative approaches to tariff design are needed to unlock the value of these resources. Importantly, there also needs to be a faster route from trialling tariffs to broad-based implementation within each regulatory control period. Greater effort is also required to coordinate the learning between networks to support the diffusion of leading approaches. Greater coordination, and more rapid deployment of tariff innovations can bring forward technology and commercial innovations that can enable technologies like V2G to support our emission reduction objectives.

12. Appendix A – Summary of key network tariff types and tariff elements

Tariff type or element	Potential benefits	Key limitations
Daily supply charge This is a common element of all network tariffs. It is typically applied on a $/day basis.	• Easy for consumers to understand • Suitable for recovering 'residual' network costs • Reflects that customer connections have a baseline cost of service regardless of electricity usage • May be appropriate for customers with high price elasticity of demand – such as V2G customers.	• Does not promote energy efficiency, distributed generation, or demand management
Flat rate tariffs Customers are charged for the volume of electricity used in a billing period. It is typically applied on a $/kWh basis.	• Somewhat easy for consumers to understand • Suited to customers with accumulation meters • Promotes energy efficiency and distributed generation	• Does not promote demand management resulting inefficient network investment costs • Allows for customers with low peak demand to cross subsidise those with high peak demand
Inclining block tariffs Rates are applied in inclining blocks (e.g., $0.20/kWh for the first 5 kWh consumed in a day, and $0.30/kWh for consumption thereafter).	• Somewhat easy for consumers to understand • Promotes energy efficiency, benefits low electricity users •	• Does not promote demand management resulting inefficient network investment costs • Difficult for customers to determine what rate they are on at a given time • Allows for customers with low peak demand to cross subsidise those with high peak demand • Can disproportionately affect low-income households due to limited access to energy-efficient appliances or insulation.
Declining block tariffs Rates are applied in declining blocks (e.g., $0.30/kWh for the first 5 kWh consumed in a day, and $0.20/kWh for consumption thereafter).	• Somewhat easy for consumers to understand • Benefits high electricity users	• Does not promote energy efficiency, distributed generation, or demand management • Difficult for customers to determine what rate they are on at a given time • Allows for customers with low peak demand to cross subsidise those with high peak demand

Tariff type or element	Potential benefits	Key limitations
Time-of-use (ToU) tariffs The $/kWh rate decreases or increases depending on time of day. Specific rates may vary between seasons or between weekdays and weekends.	• Encourages consumers to shift their energy-intensive activities to off-peak hours when electricity demand is lower. • Drive patterns of behaviours (habits) that can be developed and sustained over time. • More cost reflective – somewhat aligns pricing network LRMCs. • Can be structured to reflect average SRMCs including TUoS charges and electrical losses • On average, can augment electricity market pricing[127] delivering savings to electricity retailers. • Ultra-low off-peak pricing can reduce the cost of 'smart' electrification.	• Difficult for customers to determine what rate they are on at a given time • Some consumers can't shift their energy usage to off-peak hours due to lifestyle constraints or the nature of their work. • May not specifically incentivise the responses needed to relieve a specific constraint and defer network augmentation.[128] • May create new or secondary demand peaks as soon as the off-peak period start as large numbers of customers start charging their EVs. [129] • May disproportionately affect low-income households due to limited access to technology for energy efficiency and demand management. • TOU rates are not dynamic enough to capture infrequent scarcity events.[130]
Demand/capacity charges Applied to customers based upon the highest amount of power drawn during an interval (e.g., 30-minute) during a period (e.g., per month, billing period, annum). It can apply full-time or at a specific time of day/year).	• Can be somewhat cost reflective that it could apply in periods of high network demand • Can encourages consumers to shift their energy-intensive activities to off-peak hours when their electricity demand is lower • Capacity charges can be a way to scale residual cost recovery in line with the size of a customer's connection or maximum demand[131]. This is fairer to smaller customers. • Suited to commercial customers with the ability to schedule plant and equipment	• The higher risk profile means customers must more actively manage electricity usage to avoid bill shock. • Imposes inefficient costs on customers by incentivising behaviour change irrespective of actual network conditions. This creates inefficient costs to customers and incentives to over-invest in devices to lower customer peak demand (e.g., storage). This could impact customer electricity use diversity.[132] • Higher customer risk profiles make it a harder sell for retailers • Requires additional signals to incentive grid support services. • Does not reflect the diversity of customers.

127 T. Schittekatte et al (2022), *Electricity Retail Rate Design in a Decarbonizing Economy: An Analysis of Time-of-Use and Critical Peak Pricing* pp 9-10.

128 Ausgrid (2023) *Project Edith Knowledge Share Report*, July 2023, p 5.

129 IEEE (2023) *Impact of Electric Vehicle Charging Demand on a Distribution Network in South Australia*, p 3.

130 T. Schittekatte et al(2022), *Electricity Retail Rate Design in a Decarbonizing Economy: An Analysis of Time-of-Use and Critical Peak Pricing*, pp 9-10

131 Argyle Consulting and Endgame Economics (2022) *Network tariffs for the distributed energy future Final paper for the Australian Energy Regulator*, June 2022, p 28.

132 Ibid, p 18.

Tariff type or element	Potential benefits	Key limitations
Dynamic network prices Dynamic network prices are set for network sub-sections and vary over time (in 5-to-30-minute intervals) reflecting local network loading/congestion. Dynamic network prices are being trialled by Ausgrid under Project Edith.[133]	• Supports distributed optimisation against multiple real-time pricing signals. • Strong ability for customers to manage preferences. • Can more accurately account for both SRMC and LRMC locationally, and closer to real time. Pricing incentives align with network demand and marginal costs, supporting allocative efficiency. Over and under incentivisation is minimised. • Can prevent forecast constraint from emerging. • Leverages network capabilities gained through trials such as project Edith and the rollout of dynamic operating envelopes. [134] • Avoids challenges faced by direct network support procurement - such as baselining, verification and specific contracting.[135] • Avoids network support overpayment because it can adjust the signal to only target constrained areas rather than network. As a result, investments in network augmentation can be avoided, lowering costs for customers (including those who are not CER owners).	• Benefits only customers with significant capacity to manage price-risk exposure using automated flexible demand and generation. • Requires an agent (such as a HEMS) to manage exposure on the customer's behalf. • Could be difficult for consumers to understand. • Could result in bill shock where customers are not aware or are unable to manage price exposures. • Can require reliable elasticity curves.[136] • There is currently no nationally agreed communications protocol to support enrolment and operation at scale. • Dynamic prices may be erratic which may undermine long-run consumer behaviour change. • Some argue similar benefits can be achieved with ToU and critical peak pricing, variable peak pricing or peak- time rebates.[137] • Firmness of response is less certain, will depend on getting pricing incentives correct over time. However, this can be mitigated with complementary guard rails provided by dynamic operating envelopes.[138] • Real time computation of dynamic prices makes this more complex than other pricing arrangements but potentially less complex than network support which requires price negotiation.[139] • •

133 Ausgrid (2023) *Project Edith Knowledge Share Report*, July 2023, p 6.

134 Ibid p 22.

135 Ibid.

136 Ibid p 21.

137 T. Schittekatte et al (2022),), *Electricity Retail Rate Design in a Decarbonizing Economy: An Analysis of Time-of-Use and Critical Peak Pricing*, pp 9-10. A. Faruqui and Ziyi Tang (2023), *Time varying Rate TVRs are moving from the periphery to the mainstream of electricity pricing for residential customers in the United States,* p 13

138 Ausgrid (2023) *Project Edith Knowledge Share Report*, July 2023, p 29.

139 Ibid

Tariff type or element	Potential benefits	Key limitations
Critical peak pricing (CCP) CCP can augment existing price signals during rare network 'critical peak' events (e.g., several times a year). CPP may be combined with remote load control during critical peak pricing events[140] or serve as a penalty fee for not responding under bilateral contracting terms.	• Can provide strong incentives for reducing load/exporting during critical grid peak events. • Cost-reflective, although a smaller number of participants need to be paid more to achieve a given outcome. This may undermine productive and allocate efficiency. • Can be combined with ToU rates to target high impact scarcity events. One study found can they replicate incentives to reduce load in a similar way to spot (real time) price signals.[141]	• Benefits only customers with significant capacity to manage price-risk exposure using automated flexible demand and generation. • Requires an agent (such as a HEMS) to manage exposure on the customer's behalf.[142] • Could result in bill shock where customers are not aware or are unable to manage CCP exposures. • Could be difficult for consumers to understand and manage based on difficulty in engaging customers in simpler ToU pricing. • There is currently no nationally agreed communications protocol to support enrolment and operation at scale. • CCPs may be erratic which may undermine long-run consumer behaviour change.
Peak time rebates Customers are paid for load reductions on critical days, estimated relative to a forecast of what the customer would have otherwise consumed (their "baseline").[143]	• May be more customer friendly as framed as a benefit. • Has a had similar success to CPP, including reducing peak demand and customer rewards.[144] • Low bill volatility.	• Benefits only customers with significant capacity to manage price-risk exposure using automated flexible demand and generation • Peak time rebate programs often use baselines that are based on a customer's consumption during other high-demand days. This can create distorted incentives for conservation, as customers may be less motivated to conserve energy on those other days.[145] • May undermine long-term energy efficiency investments, as more efficient appliances reduce usage during baseline-setting times and lower the rebates.[146]

140 T. Schittekatte et al (2022), *Electricity Retail Rate Design in a Decarbonizing Economy: An Analysis of Time-of-Use and Critical Peak Pricing*, p 4.

141 ibid

142 Ibid, pp 5-6.

143 A. Faruqui and Z. Tang (2023), *Time varying Rate TVRs are moving from the periphery to the mainstream of electricity pricing for residential customers in the United States*, p 13.

144 Ibid, 11-12.

145 Borenstein (accessed 27/09/23). *Peak time rebates money for nothing*

146 Ibid.

Tariff type or element	Potential benefits	Key limitations
Transactive energy Customers subscribe to a "baseline" load shape based on their typical usage patterns. They could buy or sell deviations from the baseline on the wholesale market through sophisticated energy management systems or agents. This was originally called "demand subscription," but the idea has morphed into "transactive energy".[147]	• The transactive element enables customers and smart CERs to optimise energy management and bills by allowing them to make decisions about energy purchases or sales in advance. With machine learning and artificial intelligence becoming accessible, it encourages further energy management innovation.[148] • Reduces the potential of instability driven by over-response of flexible loads to a sharp change in price i.e., mitigates against new peaks emerging.[149] • May reduce bill volatility, while still encouraging opportunistic, beneficial load shift.[150]	• Benefits only customers with significant capacity to manage price-risk exposure using automated flexible demand and generation. • Rates are based on customer demand, not network demand. This imposes inefficient costs on customers by incentivising behaviour change irrespective of actual network benefits at a point in time. • Requires an agent (such as a HEMS) to manage exposure on the customer's behalf. • There is currently no nationally agreed communications protocol to support enrolment and operation at scale • Requires complex systems.

147 Ahmad Faruqui and Ziyi Tang (2023), *Time varying Rate TVRs are moving from the periphery to the mainstream of electricity pricing for residential customers in the United States*, p 13

148 CPUC (2022) *Advanced strategies for demand flexibility management and customer DER compensation*, p 73.

149 Ibid, p 75.

150 Ibid, p 4.

Tariff type or element	Potential benefits	Key limitations
Controlled load tariffs Customer can opt into a lower (typically flat) tariff is exchange for letting the network or another party control their appliances (e.g., water heater)	• Simple for customers to understand • High energy using appliances can be scheduled for cheaper times • Appliance operation can be aligned to forecast periods of low network load – it has a high degree of firmness. • Can make use of existing load control infrastructure (e.g., ripple control)" • Relatively easy to scale up, depending on customer's assets and willingness to participate. Although DNSPs are seeing a reduction in new load control customers due to the desire to self-consume.	• Does not support distributed optimisation (including against customer needs and other price signals). It is a broad-based network response does not account for customer constraints and utilisation issues. • Typically requires a separate electrical circuit and metering point meaning customers with self-generation, such as solar PV, cannot use their own electricity for controlled load devices. For this reason, enrolment numbers are reducing over time. • Typically works in regular time-blocks which may or may not align with actual networks peaks and troughs. • Limited to selected appliances. Also, appliances, such as water heaters, are more energy efficient than in the past, further reducing load control effectiveness. • Direct load control by networks means retailers lose some ability to manage electricity market price-risk exposures. • Some market participants have concerns with monopoly network's controlling customer appliances. They consider VPP operators, aggregators, and retailers are best place unlock the value of CER orchestration on a competitive basis.[151] • Networks are trialling tariffs using high peak price (LRMC) signals rather than direct load control. This is because it can be used for the total load including other controller devices/appliances, including for EV chargers on dedicated circuit.[152] • Does not allow customer agents to stack local and wholesale value streams.[153]
Progressive rate recovery Residual costs can be recovered through other means such as Council rates (i.e., based on land value) or be means-tested.	• Is based on a premise that electricity networks are public infrastructure and electricity is an essential service that must be connected to a premises regardless of customer means. • Can support social equity outcomes by ensuring 'public infrastructure' is paid for by those with the means to do so. • Allows for variable costs to be cost-reflective.	• If applied to variable costs (other than residual costs) it would undermine all incentives for energy efficiency, demand management and distributed generation resulting in inefficient costs for all electricity users and rate payers. • Would require substantial policy agreement between jurisdictions and legislative reform.

151 Argyle Consulting and Endgame Economics (2022) *Network tariffs for the distributed energy future Final paper for the Australian Energy Regulator*, June 2022, p 15.
152 Ausgrid (2023) *Our TSS Explanatory Statement for 2024-29*, p 57.
153 Ausgrid (2023) *Project Edith Knowledge Share Report*, July 2023, p 30.

Tariff type or element	Potential benefits	Key limitations
Centralised optimisation[154] The network is optimised for lowest cost considering market needs/and or local network constraints e.g., scheduled dispatch and market platforms.	• Firmer response than a purer incentives approach provided by opt-in dynamic pricing. • Provides independence to customers to choose their form of network support.	• Requires investment in complex, costly bidding, and dispatch platforms. Whereas dynamic pricing can leverage future committed dynamic operating envelope system capabilities. • It may have similar challenges with network support procurement including baselining and verification. • Less scalable than pure incentives provided through pricing.

[154] Ibid, p 29.

Appendix B - Details for each modelled tariff

EA025

Tariff Component	Season	Time	Charge
Daily Supply ($)	All	-	0.491497
Peak (c/kWh)	All	2-8pm	27.2634
Shoulder (c/kWh)	All	7-2pm, 8-10pm	5.5002
Off-Peak (c/kWh)	All	10-7am	3.8676

EA029 (Export Tariff)

Tariff Component	Season	Time	Charge
Export Charge (c/kWh)	All	10-2pm	1.2148
Export Reward (c/kWh)	All	2-8pm	2.2570

Dynamic Network Tariff

Tariff Component	Season	Time	Charge
Daily Supply ($)	All	-	1.00
Max Variable Charge at 80% Utilisation ($)	All	All	1.20

Origin Go Passthrough

Tariff Component	Season	Time	Charge
Daily Supply ($)	All	-	0.8802
Feed-in Tariff (c/kWh)	All	All	7
Peak 1 (c/kWh)	Winter	5-9pm	32.2903
Peak 2 (c/kWh)	Winter	2-5pm	58.0256
Shoulder 1 (c/kWh)	Spring, Autumn	7am-8pm	26.7998
Shoulder 2 (c/kWh)	Spring, Autumn	8-10pm	28.5956
Peak (c/kWh)	Summer	2-8pm	32.2903
Shoulder 1 (c/kWh)	Summer, Winter	7-10am, 8-10pm	26.7998
Shoulder 2 (c/kWh)	Summer, Winter	10-2pm	28.5956
Off-Peak (c/kWh)	All	10-7am	14.7056

Amber Spot Price Passthrough

Tariff Component	Season	Time	Charge
Monthly Subscription ($)	All	-	19
Regulatory and Market Pricing Fees (c/kWh)	All	-	2.7231
NSW Spot Prices ($/MWh)	All	-	(October 2022 – October 2023 Prices)