Value of optimised flexible DER

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Version History

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1 Contents

2 Executive summary

2.1 Background

The increase in end-consumer installation of new technology to generate and shift energy is widely documented. These technologies are often referred to as Distributed Energy Resources ('DER')[1]. There is an increasing penetration of rooftop solar photovoltaics technology ('PV'), home battery energy storage systems ('BESS'), demand-side response enablement, and an emerging focus on electric vehicles ('EVs'). Additionally, we are seeing innovation in the coordination and control of many small devices, unlocking the potential for technology within the home to meaningfully provide electricity and other services to the national electricity grid. In the context of this market transition, DER is increasingly highlighted as a resource which may offer value to customers, market participants and the wider system.

This study was commissioned by the Australian Energy Regulator ('AER') in May 2020, to provide a quantitative 'Size of the Prize' view of the potential value of optimising flexibility for a household with DER. This analysis is intended to provide the AER with insight and reference points in the ongoing discussions around facilitation of DER assets in the network, and to inform broader conversations about tariff reform.

The costs of supplying a residential customer with electricity are illustrated in the retail cost stack in Figure 1 below. DER can avoid some of these costs by:

- reducing the total amount of electricity consumed from the grid (applicable for generation technologies such as solar PV), and/or
- changing the time of that consumption from higher priced to lower priced periods (applicable to flexible assets such as batteries and EVs, which can change their operation based on price signals)

The focus of this study is flexibility – i.e. principally shifting the timing of consumption, as opposed to reduction in annual consumption. Therefore, we will focus the analysis on three key value streams, as follows:

- **Wholesale electricity –** refers to the spot price in the Australian National Electricity Market ('NEM'). This price currently changes every half hour during the day, driven by supply and demand in the electricity market. If a technology behind-the-meter acts to reduce a customer's load, it will reduce the wholesale costs to supply the home in that period. Similarly, if the customer generates more power than it can use and exports this back into the grid, then it can be sold back into the market.
- **Avoided network tariff costs –** refers to the avoidance of fees charged by network operators to retailers for a customer's use of the electricity network. These vary according to the structure and size of pre-determined tariffs which are set annually. These costs are

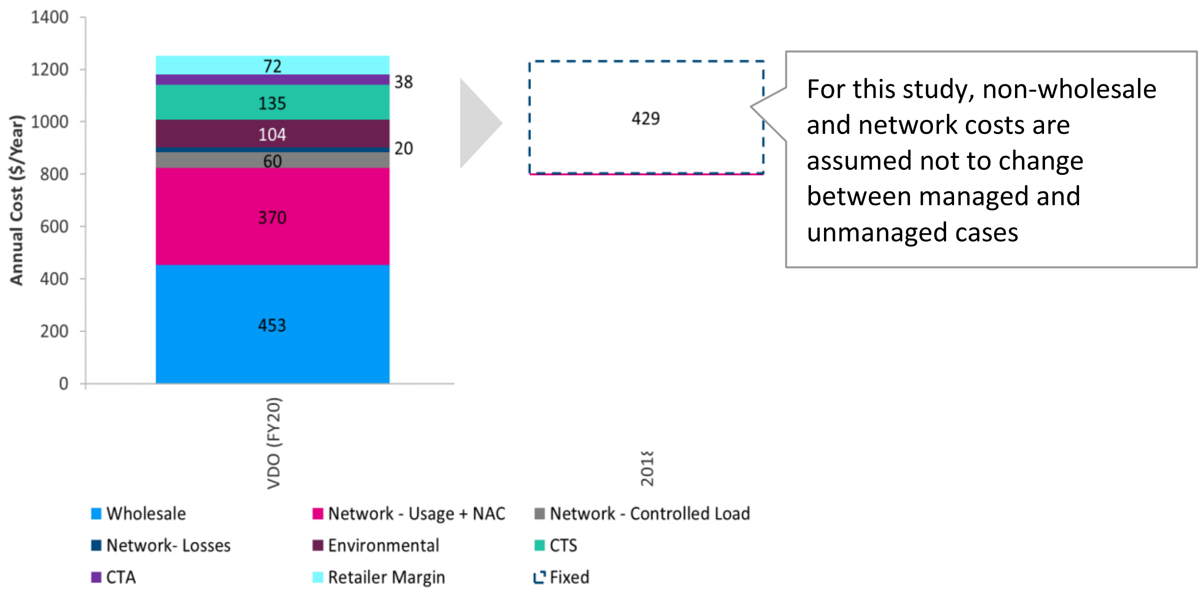
[1] DER is used in this report to describe technology located on customer site, or 'behind-the-meter', and does not include grid-scale 'front-of-meter' distribution-connected technology. We have also focused on residential DER, as opposed to business customers.

passed through to consumers, and for network prices that vary over the day, DER assets can reduce network charges paid by consumers by shifting consumption from high- to low-priced periods.

- **Ancillary services –** refers to Frequency Control Ancillary Services (FCAS) procured by the Australian Energy Market Operator (AEMO) to manage the grid. The services considered in this study are called 'Contingency FCAS', which require fast response to balance the grid in the case of an unexpected incident (e.g. a large generator trip). Revenue is received for providing these services, with prices changing every half-hour. DER optimisation can act to both increase FCAS revenues for, and decrease the allocation of FCAS costs to, customers with DER.

Wholesale and network costs represented around 65% of a typical residential customer bill in Victoria as per the FY 20 Victorian Default Offer ('VDO') as seen in Figure 1 below. It is assumed that all other costs are levied on a flat usage ($/kWh) or fixed ($/yr) basis, meaning they do not change materially if household consumption is shifted over the day. These have been assumed the same between the managed and unmanaged cases.

Figure 1 Proportion of non-wholesale or network costs for a typical residential customer



Using data from a number of illustrative typical customers, the analysis explores the potential value of managed flexibility, which includes cost reductions on the retail bill through wholesale and network charge reductions along with supplementary revenue through participation in the FCAS markets. The cases modelled are representative of an automated optimisation solution, for example from a retailer or third-party using an optimisation algorithm with full exposure to granular wholesale and network prices. The analysis assumes the end-user household energy consumption remains as it is today, with technology working 'in the background' to reduce consumer costs without requiring a significant change to lifestyle.[2]

It is also worth noting that the focus of this report is on how different assumptions on the operational profile of DER assets impact the value of these assets in terms of bill impacts for customers with DER. This assessment is based on time of use and demand tariffs from the proposed tariff structure statements ('TSS')[3] by the Victorian Distribution Network Service Providers ('DNSP'). Under some tariff structures, some or all of the costs avoided by customers with DER may be reallocated to non-DER customers, rather than resulting in overall lower costs. These equity issues are outside of the scope of this work, but are worthy of consideration in order to gain a more holistic assessment of the impact of DER on overall system costs and overall consumer welfare.

2.2 Methodology

In order to highlight the value of optimised flexibility[4], the annual wholesale and network costs for a customer with DER were measured in two cases:

- **an 'unmanaged' base case** - assumes no optimisation and very basic operation of flexible assets, and
- **a 'managed' case -** where the operation of the customer asset is optimised to minimise total wholesale and network costs for the customer and maximize revenue through ancillary services[5] .

This was completed by understanding the pattern of household energy in each half-hour over a year – referred to as a customer usage 'profile'. Illustrative typical customer profiles were derived from a dataset of consumption from 1,974 households in Victoria from 2018.[6]

For new technologies which were not well represented in the dataset (e.g. batteries and EVs), examples were taken from mass-market products available in the market. Similarly, for segments of the dataset where the average profile was not an accurate representation of a typical customer or of current market conditions, a more focussed sample size was selected. For example, in the case of households with rooftop solar PV, one hundred of the largest exporting households were selected with an average PV system size of 5kW (when compared to 2.5kW for the entire dataset), to more accurately reflect current installation sizes.

These approaches allowed us to define five illustrative customer types as outlined in Table 1 below.

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[2] The EV example modelled assumes a fixed plug-in and plug-out time, which may not be applicable to all consumer usage patterns.
[3] Submitted by AusNet, Citipower, Jemena, Powercor and United Energy to the AER in January 2020 for the regulatory period 1 July 2021 to 30 June 2026.
[4] Value is based on reduction of bill through wholesale and network costs plus revenue earned through ancillary services for a single household. It does not include any capital or operational costs for the DER asset.
[5] Participation only in the FCAS Contingency markets only
[6] Compiled by the Victorian Distribution Network Service Providers (DNSP) and ACIL Allen which focussed on customers that are more vulnerable. The selection of a typical household for this study represented a more average customer. As an example, a typical household with no DER assets consumed 4 MWh/year of energy which is in line with the consumption stated within the VDO.

Table 1 Comparison of managed and unmanaged cases

	DER Asset	Unmanaged Profile	Managed Profile
PV + BESS	5kW PV, 5kW /13.5kWh BESS[7]	Underlying profile based on a sample size of 100 customers, BESS assumed to charge only from the solar and discharge only during peak retail hours, with no grid charging or export to the grid.	Optimised BESS that minimises wholesale energy and network costs and allows for charging from the grid and export to the grid. Additional value captured by participating in the ancillary services markets.
EV	7.4kW / 50kWh EV battery	Underlying EV profile[8] was overlaid on to the usage profile of a typical customer with no DER[9].	EV available from 5pm to 7am and can provide Vehicle to Home ('V2H') and Vehicle to Grid ('V2G') services whereby the battery in EV discharges energy to the house or the grid. Additional value captured by participating in the ancillary services markets.
PV + EV	5kW PV, 7.4kW / 50kWh EV battery	Underlying EV profile[10] overlaid on usage profile for 100 PV customers.	Same as EV, with the additional availability of excess solar to meet household demand and charge the EV when the EV is available.
Pool Pump	2,240 kWh / year with pump sized at 1 kW	Underlying profile based on a sample size of 74 customers with a pool pump and no PV.	Load shifting of pool pump usage to periods of low prices, along with participation in ancillary services markets by turning the pump on or off.
HVAC[11]	HVAC load consumed at the household	Underlying profile based on a sample size of 365 customers with only electric heating and electric cooling in their household.	Demand reduction met by reducing HVAC output to 50% for 2 hours for 5 days a year. Ancillary services are is provided by turning off the HVAC when operating.

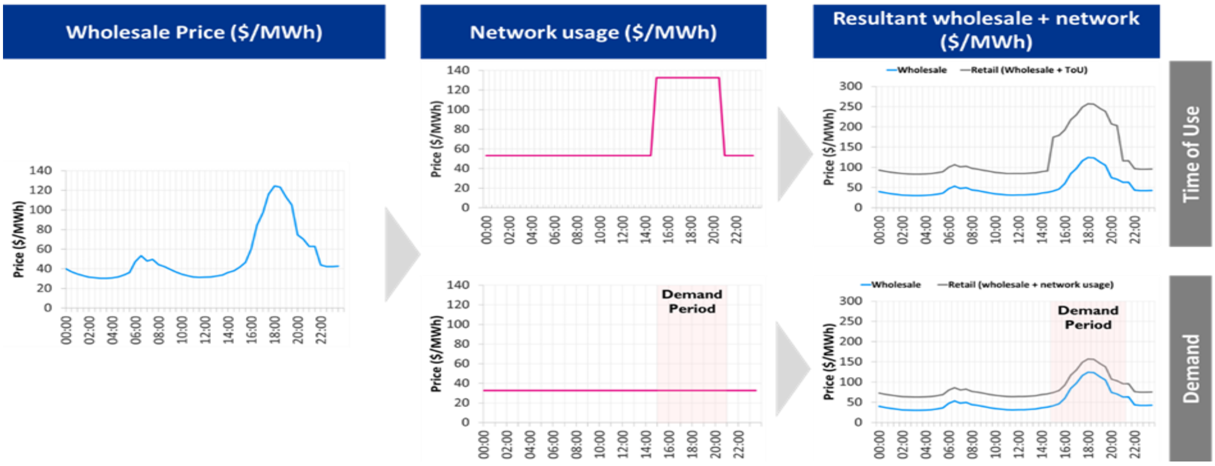
An optimisation model was run for each customer example above, allowing the asset to maximise value through avoided wholesale[12] and network costs and maximizing revenues from FCAS. This was conducted for a number of different wholesale and network price scenarios, representing differing wholesale market conditions and both time of use ('ToU') and demand-based network tariffs across the five Victorian DNSPs. ToU tariffs are volumetric charges that have different network prices at

[7] Representative of typical household BESS.
[8] EV profile based on AEMO's convenience charging profile from ESOO 2019.
[9] Profile was derived from 1,400 households with no DER assets.
[10] EV profile based on AEMO's convenience charging profile from ESOO 2019.
[11] HVAC- Heating, ventilation and air conditioning.
[12] Based on Baringa's in-house market projections (Q1 2020).

different times of the day. A demand tariff is a tariff that has a charge based on maximum demand over the specified demand period.

Figure 2 provides an illustration of how the retail stack is constructed, where the graphs on top represent ToU tariffs while the graphs at the bottom represent demand tariffs. The ToU tariffs have a higher variation in retail prices during the evening period, while the demand tariffs have flatter usage charges with costs highly dependent on usage during the shaded demand period.

Figure 2 Illustrated derivation of final retail stack for FY22 with United Energy as DNSP[13]



When several DERs are aggregated, they can participate in the FCAS market which provides further value (as a revenue stream), in addition to the cost reductions on the wholesale and network charges. This study is focused on participation in only one type of FCAS product - FCAS Contingency.[14] This is in line with the current regulatory regime, which allows small DERs to provide these services. It has been assumed that optimisation and telemetry software required to coordinate this response does not unduly delay the response of DER in providing frequency response, and therefore all Contingency FCAS products can be offered (6s, 60s and 5 minutes). This is broadly in line with results seen from recent virtual power plant ('VPP') demonstrations, for example the ongoing AEMO VPP demonstrations.[15]

2.3 Operations

2.3.1 Managed DER operations

This section describes the managed case, for each of the DER asset combinations studied.

PV + BESS: The managed PV + BESS utilises more of the solar energy within the household, which reduces both energy consumption from the grid as well as the export of excess solar energy to the

[13] Retail price shown is wholesale and network price component only, as this has been the focus of this study. It does not include network losses, environmental charges, retailer costs, controlled loads and hedging costs.
[14] FCAS Contingency is the provision of power (+/- kW) in events where the system frequency strays outside the normal operating frequency band. All products (representing response within 6s, 60s, and 5min) were included.
[15] https://aemo.com.au/en/initiatives/major-programs/nem-distributed-energy-resources-der-program/pilots-and-trials/virtual-power-plant-vpp-demonstrations

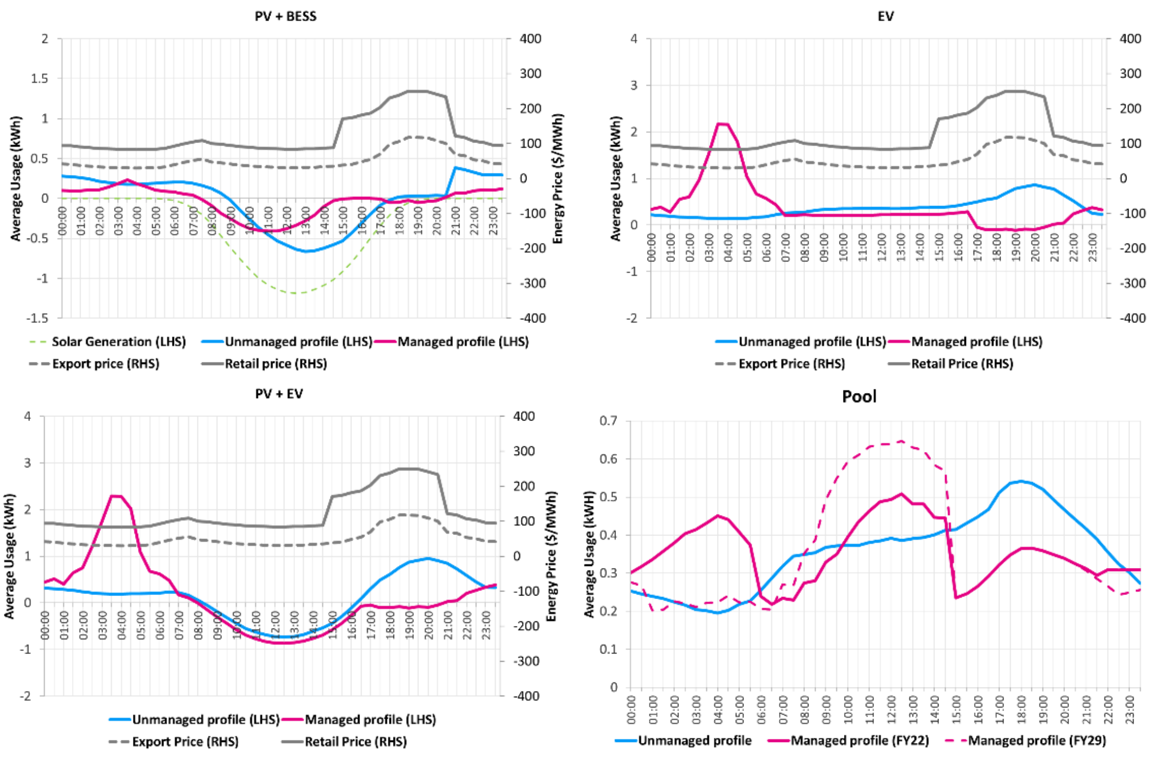
grid. The energy from the PV powers the household, charges the battery, and exports any additional generation. The BESS starts discharging once the household's energy requirement starts exceeding the solar energy being generated, and would typically continue to discharge through the evening period and may export to the grid during high price events. Figure 3 illustrates how the energy consumption of a managed PV + BESS profile is nearly zero from 2pm – 9pm on average.

EV: The EV operates in a similar manner to a BESS when it is available for use. The EV comes back home at 5pm with 85% charge and provides energy to the household through the peak retail period, and may even discharge to the grid when power prices are high. At the end of the peak period, the EV may continue supplying power to the house if prices are high. The EV typically gets charged overnight during periods of low energy and network prices.

PV + EV: The EV in this scenario operates in an identical manner to the scenario where a household had an EV but no PV. The key difference is that the household's daytime energy needs are met by the PV and any excess energy generated from the PV after 5pm charges the EV.

Pool: The managed pool pump shifts energy consumption to periods of low wholesale prices within the off peak network periods, which is 9pm to 3pm. In FY22, this occurs overnight on some days and in the middle of the day on other days, while this occurs predominantly in the middle of the day in FY29 (as seen in Figure 3 below).

Figure 3 Average daily energy consumption across a year for all DER assets (FY 22)[16]



[16] Retail price shown is wholesale and network price component only, as this has been the focus of this study. It does not include network losses, environmental charges, retailer costs, controlled loads and hedging costs.

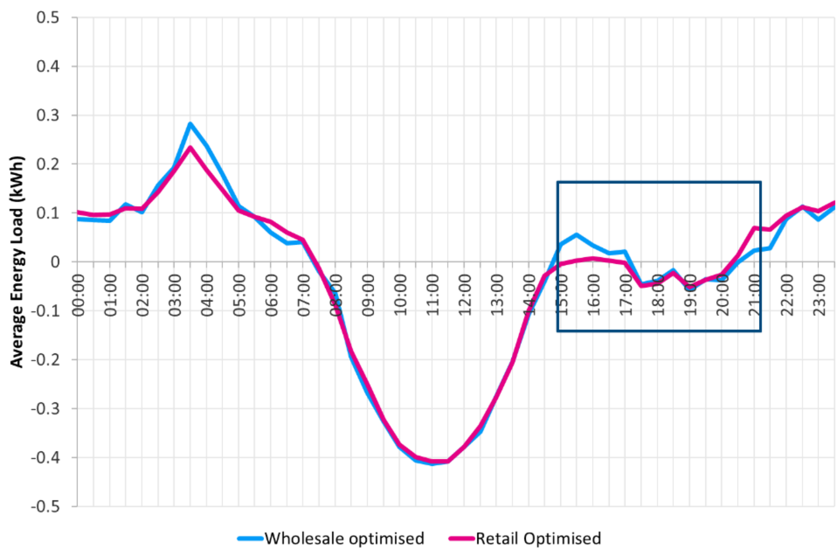
2.3.2 Influence of network prices on operations

A secondary consideration in this study was to investigate the impact that network tariff structures (which are generally time-invariant (i.e. static) or less dynamic in nature than wholesale spot prices) have on the dispatch of the BESS., For example, a time-of-use (ToU) tariff may specify a broad time window (e.g. 3-9pm) over which the network peak price is fixed, which could influence the behaviour of a BESS that responds to these prices. The BESS could discharge during this window at times when wholesale spot prices are low, or conversely the BESS could charge during the off-peak window (e.g. 9pm-7am), even though wholesale prices may be high at certain times during that window.

The impact of network tariff structures on storage operation was considered by comparing the operation of the assets when optimised against a combined wholesale and network price signal, with the operations if optimised against wholesale prices only. If dispatch is similar in the two cases, this would indicate that dispatch of the battery is well-aligned to wholesale prices (which are, in turn, a dynamic indicator of regional supply-demand), and it would also indicate that network and wholesale prices are well-aligned.

As shown in Figure 4 below, behaviour is similar in both cases. When optimising against wholesale and network prices, the BESS tends not to charge during the peak network price window,[17] and discharges less from 9-10 pm than it would otherwise. This suggests that while the peak network price window is typically well aligned to the peak wholesale price periods, there are some days in which wholesale prices peak slightly later than would be captured within the network peak period.

Figure 4 Comparison of BESS operation through retail versus wholesale-only cost optimisation for FY22



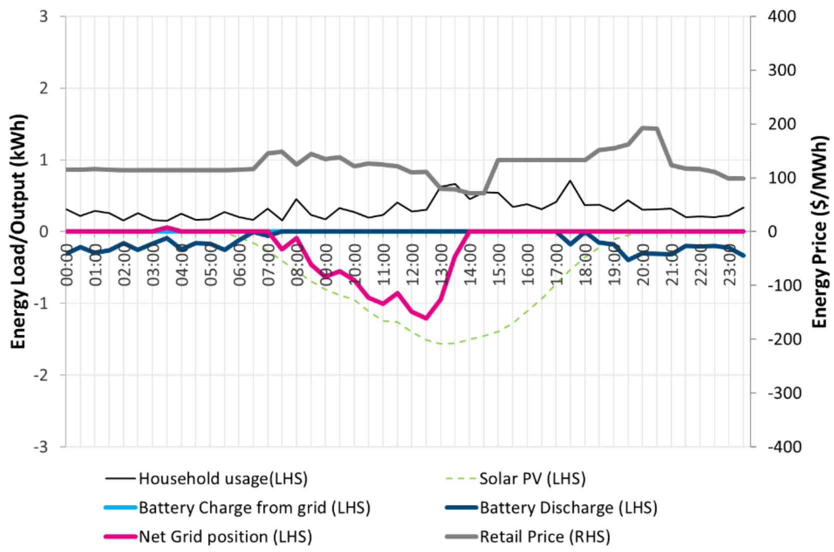
[17] Network peak price window is from 3pm – 9pm.

It was found that the wholesale arbitrage value for the BESS would increase by 3-5% when optimized against the wholesale price rather than the retail price (wholesale + network price) across FY22, FY26 and FY29. This indicates that the alignment of wholesale and network prices are similar across all modelled years.

The similarity in behaviour between the two cases is due to the typical BESS sizes chosen (as previously outlined in Table 1), which are large compared with a typical residential customer consumption over the evening peak period. This is illustrated in the two example days in Figure 5 and 6 below.

In Figure 5, the energy consumption of the household drops to zero during the day, with the PV providing power to the household and any extra energy charging the BESS. The BESS capacity is larger than a typical household's evening energy needs, and can discharge to meet the household's energy load through the entire evening peak. This avoids a potential 'cliff edge' of significant demand increases at the end of the peak network period, as seen Figure 5 and Figure 6 below. After the peak network period, the remaining energy in the BESS is dispatched according to wholesale price signals.

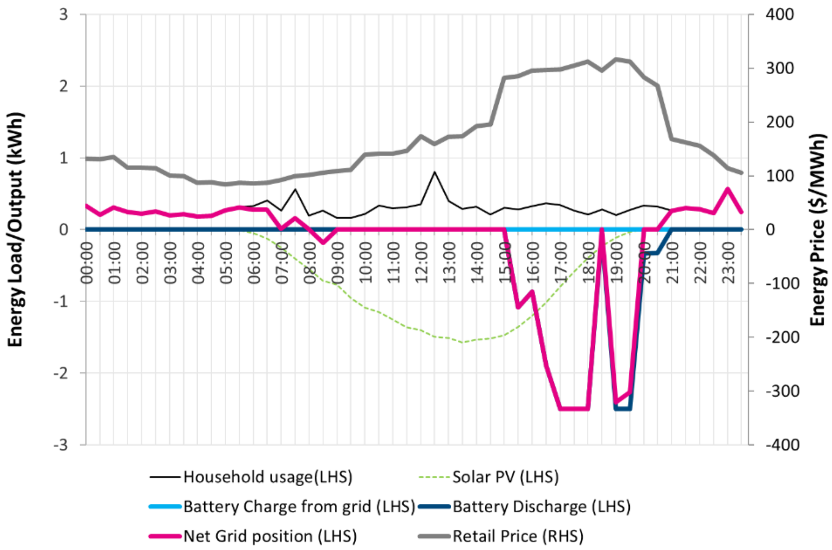
Figure 5 PV + BESS dispatch profile on a typical day [18]



However, the peak network price becomes the dominant price signal in two scenarios – when market conditions result in export of energy during high price periods and therefore less energy being available for the evening peak, or when there is reduced solar energy to charge the BESS during the day. To illustrate this, in Figure 6 the BESS dispatches most of its energy between 2pm and 7pm to take advantage of high wholesale prices, which results in the BESS being energy constrained later in the evening. When the BESS is energy constrained, the dispatch would typically align to the peak network times and potentially cause a 9pm 'cliff edge', (i.e. the BESS dispatches until 9pm, but then the household consumes energy from the grid).

[18] Retail price shown is wholesale and network price component only, as this has been the focus of this study. It does not include network losses, environmental charges, retailer costs, controlled loads and hedging costs.

Figure 6 PV + BESS dispatch profile on a high price day [19]



[19] Retail price shown is wholesale and network price component only, as this has been the focus of this study. It does not include network losses, environmental charges, retailer costs, controlled loads and hedging costs.

2.4 Key findings

2.4.1 Value of optimised charge/discharge

This study finds that the value of managed flexibility is higher for larger DER assets such as BESS and EVs, while the value is lower for non-storage assets such as pool pumps and HVAC. The value of HVAC systems is considerably lower than other assets due to their infrequent operation for managed flexibility.

As seen in Table 2, the value of a managed BESS is $1,050/yr when compared to a household with PV and no BESS. Assuming that this value is achieved every year, this represents a payback of 6-8 years[20] for the addition of a BESS to an existing PV.

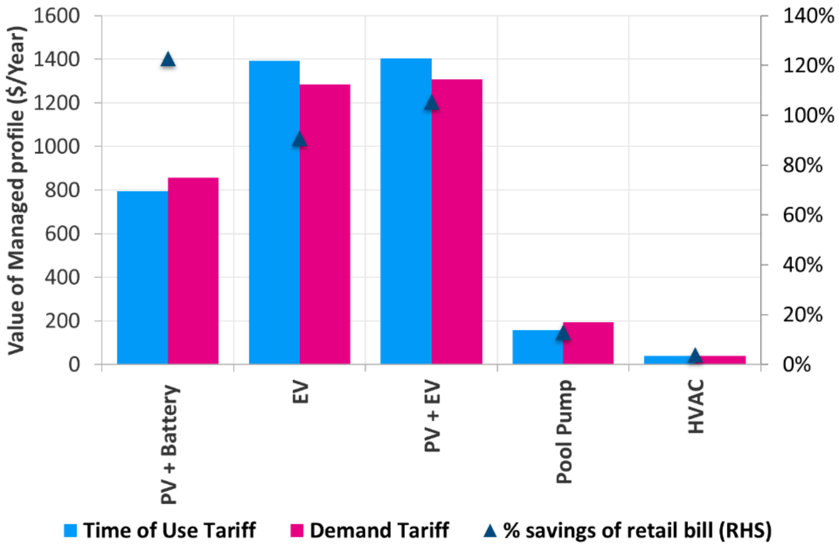
Table 2 Value of managed flexibility results

	Average annual total retail invoice[21] for unmanaged profile (FY22)	Annual value potential[22] (FY22)	Savings on total retail invoice[23] (FY22)	Value across all modelled scenarios[24]	Proportion of value from ancillary services
PV only household[25] (no DER)	$915	$1,065	117%	$975-$1,550	65%
PV + BESS	$675	$825	123%	$800- $1,300	65%
EV	$1,475	$1,340	91%	$1250-$1,950	50%
PV + EV	$1,285	$1,350	105%	$1,250-$1,900	50%
Pool	$1,370	$180	13%	$150-$280	25%
HVAC	$1050	$40	4%	$45-$50	45%

[20] Assuming that the cost of the BESS is $11,000 to $13,000 and has access to the full $4,838 battery rebate offered by the Victorian government. The ongoing operational and control technology expenditure has been assumed to be $0.
[21] Total retail bill has not been a focus of this study and been approximated here for illustration by taking cost estimates of $429/year for network losses, environmental charges, retailer costs, hedging costs and controlled load costs from the VDO and assuming these are flat on a $/kWh usage or $/year basis in all years. Based on average across all DNSPs.
[22] Value potential is based on reduction in wholesale and network costs along with revenue from ancillary markets. Costs, i.e. Capex, control, or operational costs of assets are not included. Based on average across all DNSPs.
[23] Total retail bill has not been a focus of this study and been approximated here for illustration by taking cost estimates of $429/year for network losses, environmental charges, retailer costs, hedging costs and controlled load costs from the VDO and assuming these are flat on a $/kWh usage or $/year basis in all years.
[24] Includes modelling across four different modelled years, two tariffs types and five DNSPs.
[25] Based on typical household profile with PV and no DER such as a BESS. Value potential based on comparison between unmanaged household with only PV and a managed household with PV and BESS.

As seen in Table 2, the value of a managed BESS is $1,050/yr when compared to a household with PV and no BESS. Assuming that this value is achieved every year, this represents a payback of 6-8 years[26] for the addition of a BESS to an existing PV.

Figure 7 Value of managed flexibility by asset and by network tariff type in FY22 [27] (average across all DNSPs)



All values shown should be considered illustrative of a theoretical maximum value achievable for the technical parameters modelled. This is due to the fact that the modelling has been done on a 'perfect-foresight' basis (i.e. it assumes that wholesale prices and network tariffs can be forecast each half-hour with 100% accuracy) and assuming 100% availability of DER when at the residential property. In this study, we have not considered the capital costs of installing the technology, nor the costs of operating and maintaining it. These would need to be considered by the customer when determining if a DER asset was an economic investment, and the expected pay-back period.

Similar levels of value for managed flexibility are seen for ToU and demand network tariffs for customers with storage assets (whether home BESS or within the EV). This is because these assets are sufficiently large to reduce the customer's demand (thereby reducing the $/kW demand charge) and consumption to zero through the ToU or demand peak period, which is from 3-9pm.

[26] Assuming that the cost of the BESS is $11,000 to $13,000 and has access to the full $4,838 battery rebate offered by the Victorian government. The ongoing operational and control technology expenditure has been assumed to be $0.

[27] The savings of the retail bill is a reduction on the total retailer bill. The Total retail bill has not been a focus of this study and been approximated here for illustration by taking cost estimates of $429/year for network losses, environmental charges, retailer costs, hedging costs and controlled load costs from the VDO and assuming these are flat on a $/kWh usage or $/year basis in all years.

2.5 Commercial considerations

2.5.1 Value capture

The values presented in this study are calculated on a perfect foresight basis, for individual example customers. It is assumed that the party optimising the assets has the ability to accurately predict prices and that the DER is always available within the parameters assumed.

The proportion of perfect foresight value captured for a given available asset will vary depending on the sophistication of the optimisation solution and market conditions, in particular pricing volatility. From our market due diligence work, we understand that the available battery storage technology operating in the NEM currently can capture around 75%-90% of the total perfect foresight value through optimisation algorithms.

Availability of customer assets further impact annual revenues. For relatively new assets which are located permanently in the customer home, such as BESS systems, a high availability (typically above 90%) can be assumed.

For assets such as EVs, predicting availability of the battery is more difficult. The modelling contained in the study assumes a car returns at 5pm with the battery around 85% full, and is required by the customer to be 100% full at 7am, all while maintaining a minimum charge of 20% for unexpected travel requirement. This example was selected to be consistent with the average daily energy consumption of 7kWh from AEMO's ESOO,[28] and the battery size of a Tesla Model 3 Standard car,[29] while providing a view of maximum potential value assuming significant flexibility and ability for the battery to discharge to meet evening peak.

However, recent mass-market studies which have been conducted in the UK by the Energy Technologies Institute[30] suggests a significant variation in customer behaviour across a trial of 50 customers (sample size extrapolated through modelling to 100,000 customers). As shown in Section 7 of the report, the aggregate behaviour of consumers implies that they tend to plug-in on average once every few days. In addition, while post-work charging is the most common plug-in time, there is significant variability to charging time throughout the day. While customer behaviour will vary across markets with driving patterns and range requirement, a similar level of variability is expected to exist for Australian customers (particularly in urban areas where deployment will be highest). This variability, and particularly the average availability of the EV to be plugged in and available to discharge through the evening peak price period, will have a significant impact on total value across a portfolio.

Finally, we have assumed that the household will not impact market pricing, however when several households operate in a similar manner there may be a significant impact on pricing, which may result in reduced value. The price projections used in this study account for some level of embedded energy storage in Victoria but a significant variation from this may impact wholesale prices, FCAS prices and the total value of managed flexibility.

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[28] Residential, Convenience Charging profile (VIC, Central) from AEMO's 2019 Electricity Statement of Opportunities Inputs and Assumptions workbook

[29] https://ev-database.org/car/1060/Tesla-Model-3-Standard-Range

[30] D7.3 – Demand Management Aggregator Framework, ETI ESD Consumers, Vehicles and Energy Integration Project 2019

For these reasons, values shown should be considered as a maximum potential value, under the conditions modelled, with discounts applied to account for imperfect price forecasting, asset availability and limited feedback of DER on market prices.

2.5.2 Customer products

There are a relatively small number of tariffs designed for customers with flexible DER today, and they tend to have low scale and maturity. However, retailers are innovating at pace and there are a range of trial products that do exist nationally and internationally which provide a level of insight into how the market may evolve to facilitate DER flexibility, as well as the impact of varying tariff structures,

Two broad ways to elicit response from flexible DER have been categorised in Figure 8 below. Either a retailer or other third party directly controls the asset ('Prices for Devices'), or a price signal is passed through to the customer to change its behaviour ('Active customer flexibility').

Figure 8 Spectrum of customer product design options

Prices for Devices		Active customer flexibility
The customer gives the supplier remote control of some assets to create flexibility. **The retailer gives the customer a discount which reflects the value it can create from the flexibility, via a simplified tariff**		**The retailer exposes the customer to price shape to incentivise a response from flexibility.** **The customer is responsible for generating value by optimising their demand.**
The retailer takes risk on being able to realise the assumed level of flexibility, which will have been priced.	Risk	The customer takes risk on value being created from flexibility.
The retailer has full market access and granular price signals.	Price	The price signal available to the customer is defined by the retailer.
Centralised control solution required for direct control of larger discrete loads. Typically high ability to flex load.	Control	No centralised control solution required, allowing small loads to be flexed. Customer behaviour drives ability to flex load.

There are three key themes emerging in this space:

1. **The majority of Prices for Devices tariffs have been focused on large DER technologies**. This is perhaps unsurprising given the significantly larger value available, as outlined in this report. In addition, there are proportionally lower control costs for single large, discrete assets compared with multiple smaller home devices.

2. **A price signal to the customer is common for electric vehicle tariffs**. For assets such as EVs, where customer behaviour has a larger impact on the total value which can be realised, there are more examples of tariffs which provide a price signal to the customer. This is because customer plug-in time is harder to predict and has a material impact on value captured.

3. **Prices for Devices offers for smaller assets have seen less recent development.** Due to the complexity of control and optimisation of a large number of small household assets, and the relatively low value of flexing load such as pool pumps, HVAC or whitegoods, tariffs designed for optimisation of smaller scale flexibility have been less of a recent focus for retailer tariff development. While controlled load tariffs for hot water systems have been evident for many years, recent development of flexible tariffs for smaller assets have tended to pass granular price signals directly through to the customer.

While many of these examples are trials, or low-maturity products, their presence suggests that retailers or aggregators expect to achieve value from managing flexible DER. Also, that they are willing to manage the risk which arises from managing customer flexibility while providing the customer with a simplified tariff structure. This may offer an opportunity for customers with DER who do not want to actively engage in the optimisation of their assets in the market with an opportunity to realise value from flexibility.

2.6 Conclusions

The analysis considered in this study indicate the following key conclusions:

- **The value of optimisation and management of DER is particularly high for large storage technologies such as BESS and EVs**. The additional annual value of optimised, or 'managed' charging ranged from \$800-\$1,300 for PV + BESS systems, \$1,250-\$1,950 for EVs and \$1250-\$1,900 for PV + EVs across the different scenarios considered, which included four different modelled years, two tariffs types and five DNSPs. Whilst the value of large storage technologies are similar, they represent considerably different customer propositions, as the purchase of a BESS to supplement an existing PV is different to the marginal additional cost of purchasing an EV when compared to a traditional combustion vehicle.
- **For the typical customers considered, both ToU and demand tariffs provide similar levels of value in most cases.** This is because with EVs and home BESS sizes in line with current market trends, there is sufficient storage to reduce household consumption to zero over the evening peak period.
- **These high-value DER assets have also been the focus of most 'Prices for Devices' style products to date**, with an aggregator or retailer optimising the behaviour of the technology on behalf of the customer, and passing a simple tariff structure through. This is due to the high total value, and relatively low costs for central control.
- **For optimisation of other DER, such as HVAC or pool pumps, the value is smaller but maybe easier and cheaper to implement with lower payback costs.** Traditionally flexible response for these technologies has been driven by direct customer response to a price signal, which does not require centralised control technology.
- Many of these products in the market today are currently in trial phases, and available for a limited number of customers. However, **if proven commercial at scale, these products would signal an opportunity for the coordination of DER response** while maintaining simplicity for the customer and limited impact on the end-user experience of using electricity.

3 Glossary of Acronyms

AEMO – Australian Energy Market Operator

AER – Australian Energy Regulator

BESS - Battery Energy Storage System

CAL18 – Calendar Year 2018

CTA – Cost to Acquire

CTS – Cost to Serve

DNSP – Distribution Network Service Provider

DR – Demand Response

DER – Distributed Energy Resources

DLF – Distribution Loss Factor

ESOO – NEM Electricity Statement of Opportunities

EV – Electric Vehicle

FCAS - Frequency Control and Ancillary Services

FY22 – Financial Year 2022

FY26 – Financial Year 2026

FY29 – Financial Year 2029

HVAC – Heating and Ventilation Air Conditioning

NAC – Network Access Charge

NEM – National Electricity market

PV – Photovoltaic System

PV + BESS – Photovoltaic system + Battery

PV + EV – Photovoltaic System + Electric Vehicle

PiV - Plug in Vehicles

ToU – Time of Use

TSS – Tariff Structure Statement

VDO – Victorian Default Offer

V2G- Vehicle to Grid

V2H- Vehicle to Home

VPP – Virtual Power Plant

4 Methodology

This section of the report describes the detailed methodology used for the analysis. This includes the derivation of unmanaged profiles, derivation of the retail price stacks and assumptions used to model the managed profile.

4.1 Unmanaged profiles

Illustrative customer profiles were derived from a dataset of 1,974 households in Victoria from 2018.[31] The profiles were filtered by the type of DER asset at the household and classified into four key segments:

- House with no DER assets
- House with PV only
- House with pool only
- House with PV and pool

A summary of the dataset by asset segment and tariffs type can be found in Table 3 below.

Table 3 - Summary of respondents by tariff and asset segments

Tariff Type	No DER	PV only	Pool only	PV & Pool
Flat	1263	152	65	22
ToU[32]	95	320	11	46
Total	**1358**	**472**	**76**	**68**

The methodology to derive typical customer profiles was set with two criteria. Firstly, that the annual average daily shape (i.e. the average over a year of the energy consumption in each half-hour period of the day) was in line with the average of all customers within this segment. Secondly, that the day-to-day variability, which drives peak demand charges, was representative of a typical customer.

For example, for customers without DER, this resulted in three steps outlined below to create a 'no DER' profile.

- A year of half-hourly consumption data was averaged across 1,358 customers, to understand the average consumption profile over the year, and typical daily shape.
- A typical household was chosen, which had average daily shape closest to the average of the entire sample set.

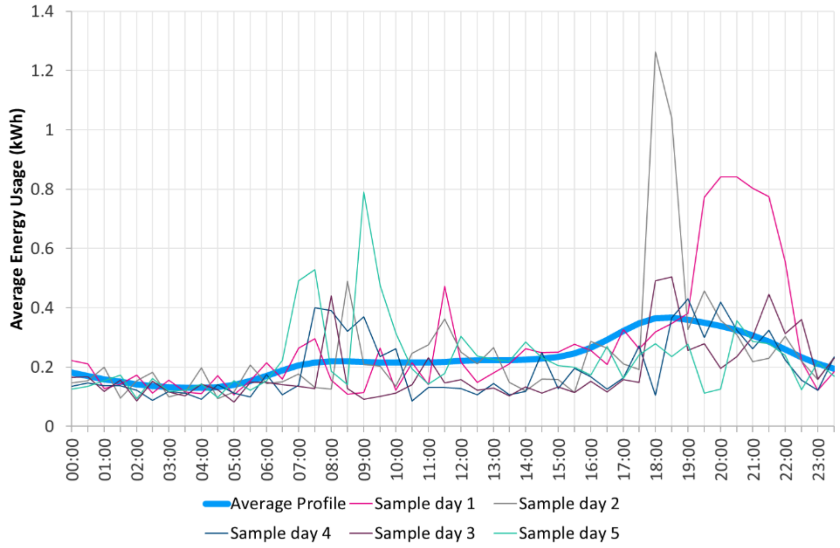
[31] Compiled by the Victorian Distribution Network Service Providers (DNSP) and ACIL Allen which focussed on customers that are more vulnerable. The selection of a typical household for this study represented a more average customer. As an example, a typical household with no DER assets consumed 4 MWh/year of energy which is in line with the consumption stated within the VDO.

[32] ToU- Time of use tariffs have different prices for electricity at different times of the day.

▸ The day-to-day variability of consumption from this customer was applied to the average consumption profile.

This resulted in a half-hourly consumption profile for a typical customer over a year, with the usage varying to be representative of a more typical household as seen in Figure 9 below.

Figure 9 Average daily energy consumption of households with no DER assets



4.1.1 Unmanaged PV + BESS

A similar process was used to derive the unmanaged profile for a household with a PV + BESS.

Given that net load data was provided, it was necessary to derive an implied PV system size for the profile, using an average Victorian rooftop solar PV profile.[33] The average PV system size across the 472 households in the dataset was found to be 2.5 kW, but we chose to focus on larger system sizes which were more in line with current installation sizes. This also ensures that the size of the PV system would be large enough to be eligible for the Victorian government's solar battery rebate.

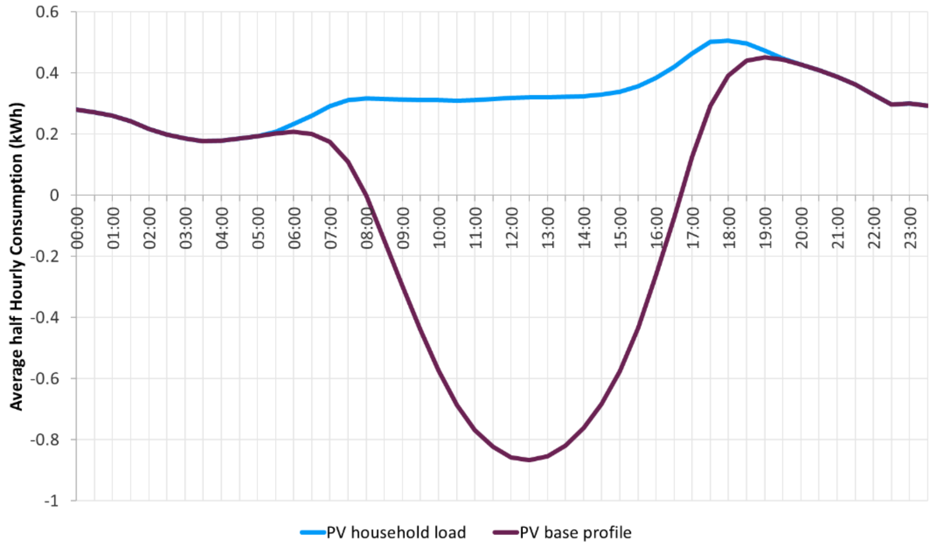
Profiles across the 100 largest exporting households were analysed and it was found that the average PV system size across these households was 5kW. The maroon line in Figure 10 is the average daily shape of a PV household profile for the 100 largest exporting sites. The energy requirement for the household during solar hours was calculated by subtracting the output of a 5kW system from the average profile of the 100 households.

As shown in the figure below, the average large solar PV customer appears to have higher overnight consumption when compared to customers with no DER assets. This is likely due to the fact that a

[33] The average profile was sourced from AEMO based on the actual rooftop PV output across Victoria in calendar year 2018 to ensure that the PV profile and household loads were from the same period. System capacity factor was assumed to be 15%.

majority of this sample set are currently on time of use tariffs,[34] which reward shifting of consumption to off-peak periods. Given this flexibility was not related to a specific customer asset studied, it was included in the unmanaged profile.

Figure 10 Average daily energy consumption of households with PV



There were no customers flagged to have a BESS, so we super-imposed the operations of a BESS with a basic algorithm to create an 'unmanaged' PV + BESS profile. The BESS operating logic and system configuration can be found in Table 4.

Table 4 Unmanaged PV + BESS system configuration

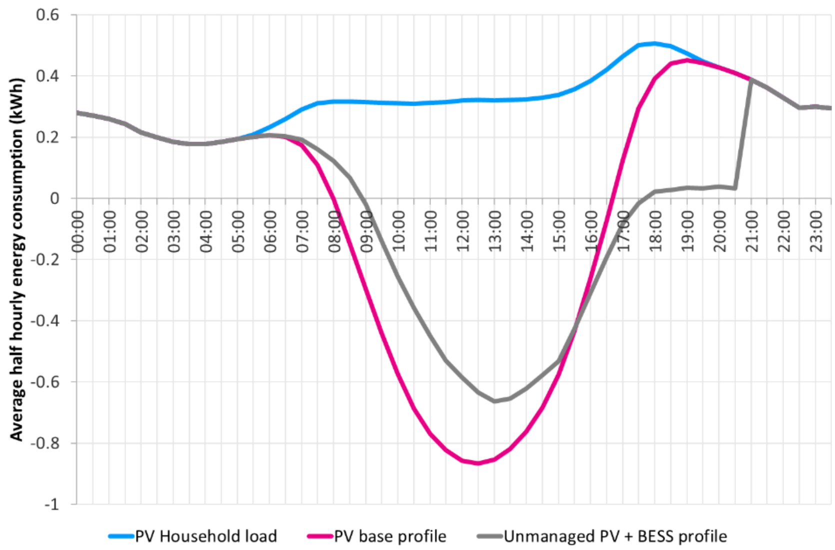
Category	Sizing
PV System Size	5 kW
BESS storage duration	13.5 kWh
BESS rated capacity	5 kW
BESS round-trip efficiency	90%
Operating Logic	- Solar supplies household load first - Excess solar feeds BESS - BESS discharges 3-9pm to meet household load - No export of BESS to grid, or charging from grid

It was assumed that the BESS would discharge only during peak network periods and will not interact directly with the grid. Excess energy from the PV charges the BESS, and the BESS discharges only to meet household energy requirements (as the export price for the excess solar is considerably lower than the peak energy usage price thereby incentivizing self-consumption and minimizing export). While this operation is not truly 'unmanaged' it was chosen to represent a simple operation of a BESS which does not have the ability to export or optimise against wholesale prices. The average shape of the unmanaged PV + BESS profile can be found in Figure 11 below, where it is visible that the BESS

[34]Time of use tariffs have different prices for electricity at different times of the day with overnight prices being considerably cheaper.

absorbs some of the excess solar energy during the day to meet the majority of the evening household energy requirements. It is worth noting that the low annual average grid consumption over this period is due to a net zero consumption on the majority of days, with some grid consumption on a minority of days where there is insufficient energy from the PV to charge the BESS to meet household energy needs through the entire evening peak period.

Figure 11 Average daily energy consumption of unmanaged PV + BESS

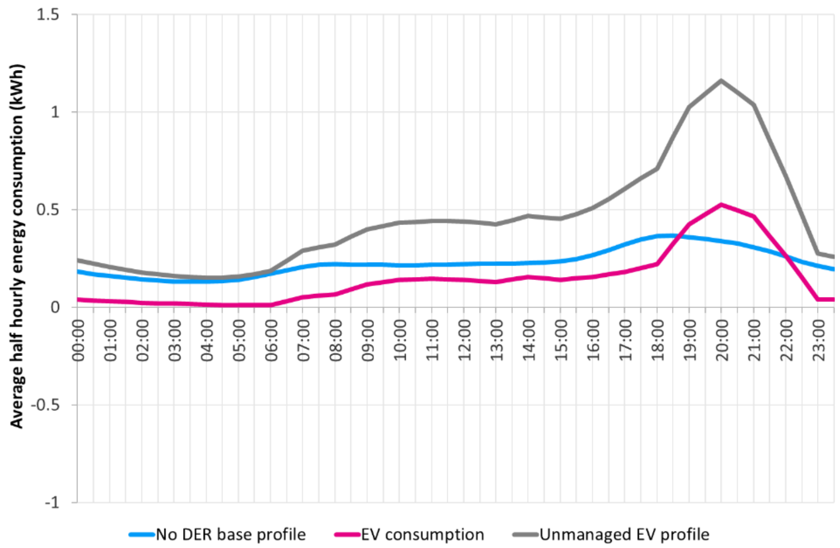


4.1.2 Unmanaged EV

The unmanaged EV profile was derived by overlaying the no-DER base profile with AEMO's projection of EV consumption as per the NEM Electricity Statement of Opportunities ('ESOO') 2019. The average energy consumption per residential EV was found to be close to 7 kWh/day (2.5 MWh/year) based on the central case for Victorian EV demand and uptake projections in the ESOO. It was assumed that the EV charging pattern of the unmanaged case would be the same as the residential convenience charging pattern in the ESOO.

The average daily shape of the EV consumption along with the unmanaged EV profile can be seen below in Figure 12, where the unmanaged EV profile is the sum of the base profile for households without DER assets and the EV consumption profile from the ESOO.

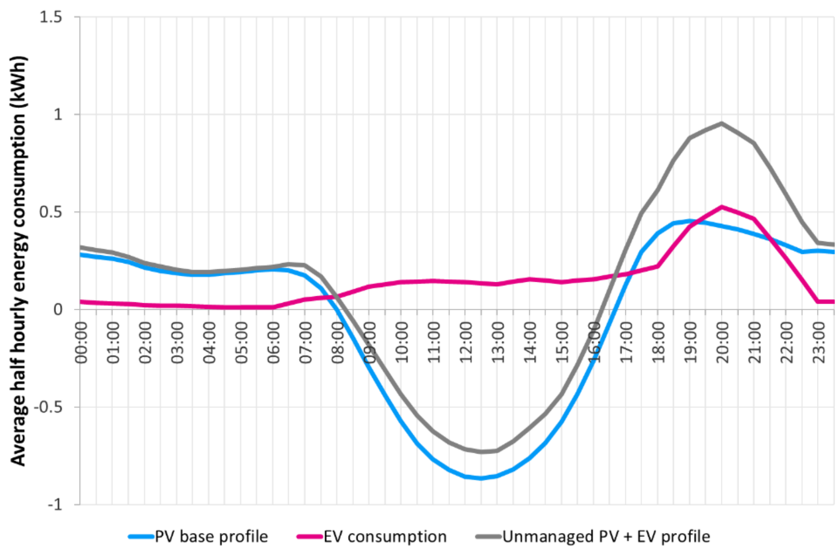
Figure 12   Average daily energy consumption of unmanaged EV



4.1.3 Unmanaged PV + EV

The unmanaged PV + EV profile was derived in a similar manner to unmanaged EV profile. This was done by overlaying the PV base profile with the same EV profile from AEMO's projection of EV consumption as per the ESOO.

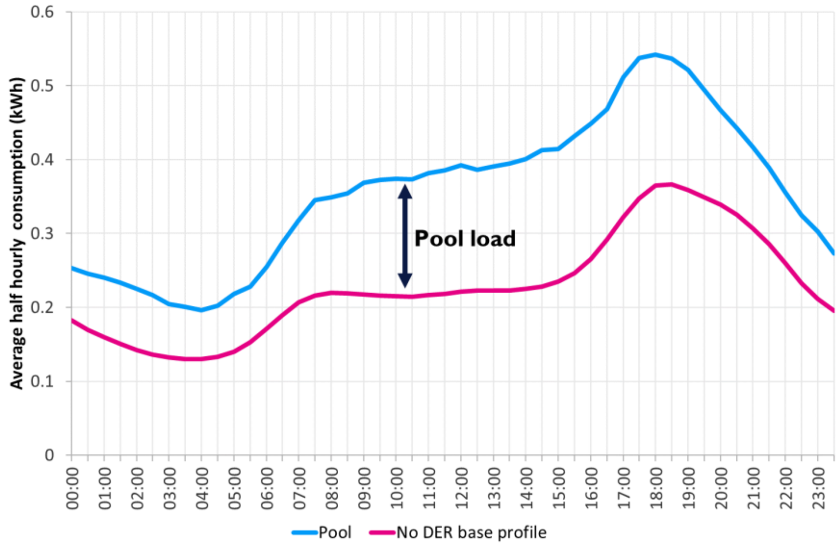
Figure 13   Average daily energy consumption of unmanaged PV + EV



4.1.4 Unmanaged Pool

The average consumption of all customers (76) in the dataset that had a pool and no PV was used to derive the unmanaged pool profile. As with the other profiles, this average profile was scaled to account for daily usage variability using a customer whose profile closely fits with the average shape. The pool load, which is 2,240 kWh/year, was the difference between the pool profile and the no-DER profile. This is broadly in line with a 1kW pool pump running for a little more than 6 hours every day.

Figure 14 Average daily energy consumption of unmanaged pool profile



4.1.5 Unmanaged HVAC

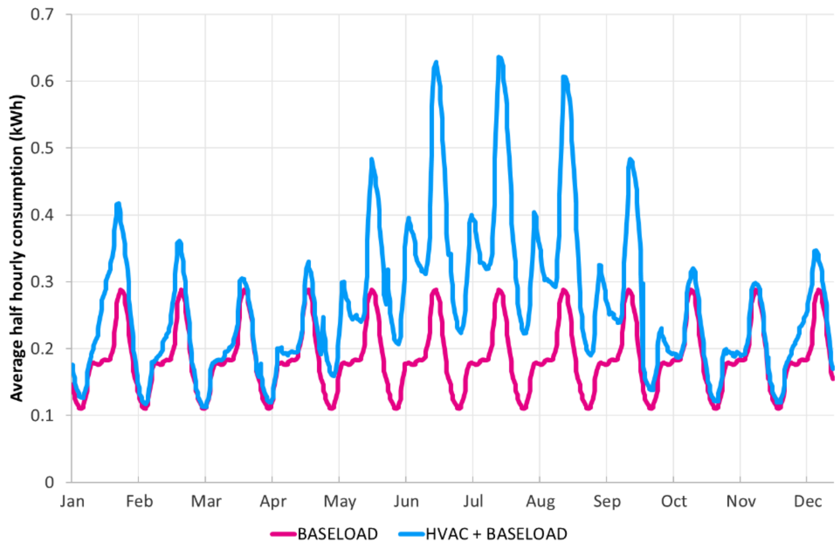
The unmanaged HVAC profile represented a typical household that had only electric heating and cooling (ducted or split system). Households with other types of HVAC systems and households with gas heating were not included in the unmanaged HVAC profile.

The HVAC load of the household was derived in three steps:

- Taking the average profile of all customers with no DER assets and had only gas heating to derive a non-HVAC baseload for the period from March to November.
- It was assumed that there would be minimal electric cooling during the months of March, April, October, and November. The average usage across these months was assumed to be the non-HVAC baseload for Jan, Feb and Dec as seen by the pink line in Figure 15 below. The baseload usage was consistent across all months.
- The HVAC load was found to be the difference between the average HVAC profile of a house with electric heating and cooling and the average baseload profile, on a half hourly basis accounting for customer variability.

Figure 15 shows the consistent baseload profile with varying HVAC requirements through the year. For these HVAC customers with no gas heating, it was found that energy consumption was higher in winter than summer. In winter, the average daily profile shows an increase in HVAC load in the mornings before reducing through the day and increasing further during the evening period.

Figure 15 Average daily unmanaged HVAC profile by month



4.2 Price assumptions

We selected calendar year 2018 ('CAL18'), financial year 2022 ('FY22'), financial year 2026 ('FY26') and financial year 2029 ('FY29') to represent a number of different wholesale and network price scenarios. For each year, both ToU and demand-based residential network tariffs were modelled across the five Victorian DNSPs.

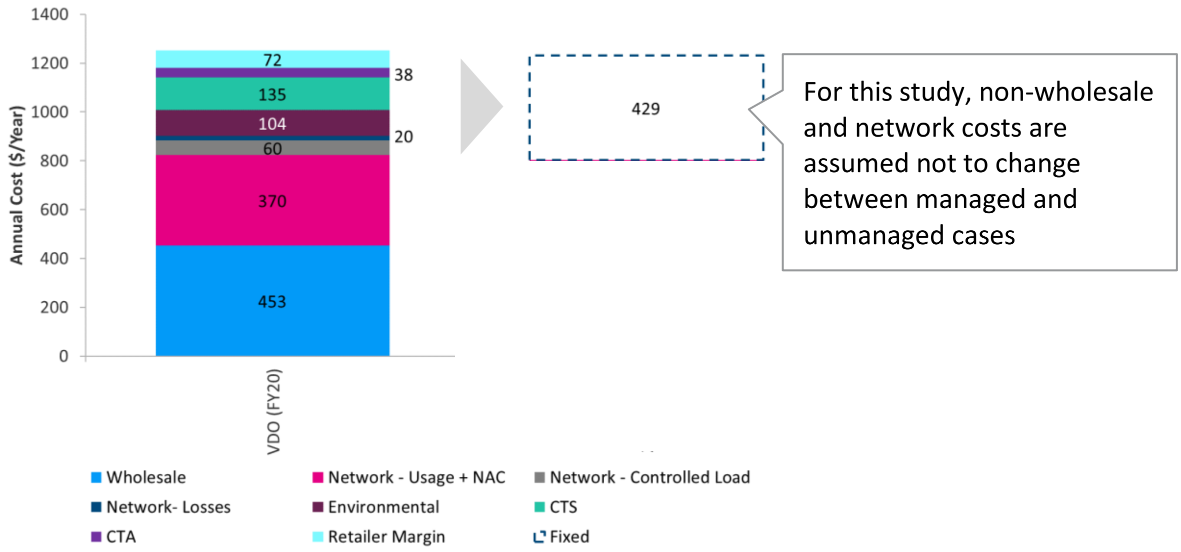
4.2.1 Focus area of retail stack

Wholesale and network[35] costs account for approximately 65% of the total household bill for a customer based on the current VDO, as seen in Figure 16. Given that these costs vary across the day with the household's energy consumption and create value for load shifting, they are the focus of the results presented in this report.

The remaining costs, which is about 35%, have not been a focus of the analysis as they do not change through management of the household's usage profile and are individually too small to impact value.

[35] Network costs represent both usage and fixed Network Access Charges ('NAC') where the fixed NAC cannot be influenced by load shifting. This charge has been included in the analysis due to the variation of the NAC by Distribution Network Service Provider (DNSP).

Figure 16 Proportion of non-wholesale or network costs for a typical residential customer



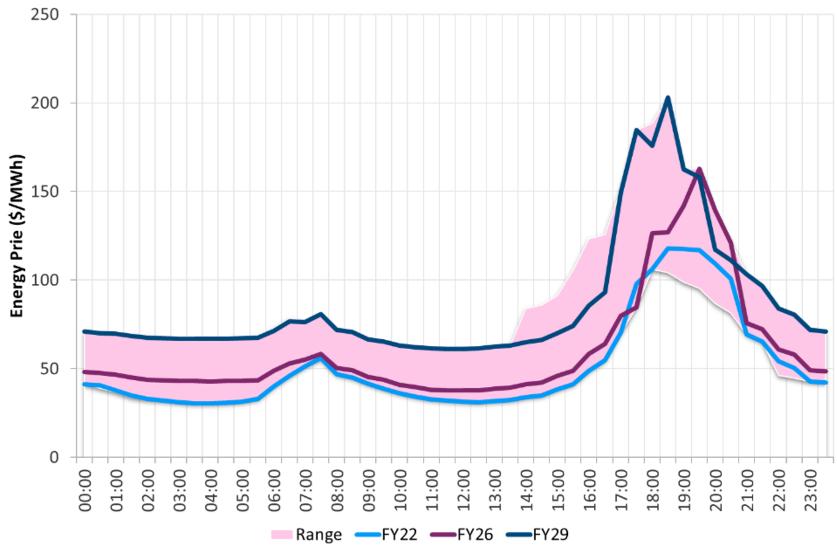
4.2.2 Wholesale Energy & FCAS Prices

The wholesale energy prices used to develop the cost stack were half hourly Victorian energy prices from Baringa's long term (Q1 2020) Reference Case price projections.

Due to varying market dynamics, both the daily average wholesale price and the daily price shape are projected to change between 2021 and 2030 as seen in Figure 17 where the pink area represents the range seen through the ten years. For this analysis, we chose the following years to represent varying price and market conditions:

- Calendar Year 2018: Representative of the historic year from which customer household data was obtained.
- Financial Year 2022: This is the first year of the new Tariff Structure Statement (TSS) and represents a low price year as seen in Figure 17.
- Financial Year 2026: This is the last year of the new TSS and represents a year with mid-level baseload prices and high price spreads as seen in Figure 17.
- Financial Year 2029: This year was included to show a year of high baseload prices. In Baringa's Reference Case modelling, this is due to a sharp reduction of coal generation in Victoria (approximately 10TWh) in FY 2028 on the back of the projected closure of Yallourn West. Price spreads are similar for both FY26 and FY29.

Figure 17 Average Daily price shape for Victoria



The annual FCAS price projections for FY22, FY26 and FY29 were based on Baringa's in-house long term Reference Case (Q1 2020) FCAS price projections. For CAL18, actual annual FCAS prices was used.

Table 5 Average annual FCAS prices

Annual Average Prices (Mainland NEM)		Range over modelled horizon
Contingency Raise (6s, 60s)	$/MW/hr	6.9 - 10
Contingency Raise (6s, 60s)	$/MW/hr	6.9 - 9.3
Contingency Raise (5min)	$/MW/hr	7.0 - 15
Contingency Lower (6s, 60s)	$/MW/hr	0.0 - 0.9
Contingency Lower (6s, 60s)	$/MW/hr	0.0 – 0.9
Contingency Lower (5min)	$/MW/hr	0.0 – 0.6

4.2.3 Network Prices

The modelling was based on both time-of-use (TOU) energy tariffs and peak demand- tariffs for residential customers. The proposed Tariff Structure Statements[36] ('TSS') from the five Victorian Distribution Network Service Providers (DNSP) for 2021- 2026 was used to select the relevant tariffs.

The proposed TSS of all DNSPs have aligned both time of use and demand peak periods for residential tariffs and are:

[36] Submitted by AusNet, Citipower, Jemena, Powercor and United Energy to the AER in January 2020 for the regulatory period 1 July 2021 to 30 June 2026.

Time of Use:

- Peak hours: 3pm - 9pm everyday
- Off peak hours: 9pm – 3 pm everyday

Demand:

- Peak demand period: 3pm – 9pm weekdays
- Demand is measured as the maximum half-hour kW demand during the peak demand period

The structure of the ToU tariffs in 2018 was different to the structure of tariffs in the new TSSs. Given that the aim of this study was to look at the impact of the proposed tariffs across different wholesale and FCAS market conditions, a new proxy ToU tariff was derived for 2018 for each DNSP using the 2018 tariffs and data from the respondents. The data from all households which were on a flat tariff was used to calculate the revenue that a DNSP would have received from those customers. A peak and off-peak tariff was calculated for each DNSP based on its off-peak to peak price ratio in order to receive the same total revenue across the customer group for each DNSP as seen in Table 6.

Table 6 Derivation of proxy 2018 ToU tariff by DNSP

	Customers [A]	Revenue ($) [B]	Peak Usage (kWh) [C]	Off-Peak Usage (kWh) [D]	Off-peak to Peak Ratio [E]	Fixed Charge ($/Year) [F]	Peak Rate (c/kWh) [G]	Off-Peak Rate (c/kWh) [H]
AusNet	446	$235,978	632,820	1,184,025	5	109	**21.55**	**4.31**
Citipower	89	$24,879	90,214	179,890	2.5	85	**10.68**	**4.27**
Jemena	179	$64,289	238,636	446,554	3	45	**14.53**	**4.84**
Powercor	431	$182,945	638,834	1,158,804	2.5	125	**11.71**	**4.68**
United Energy	340	$119,846	493,154	874,035	2.5	25	**13.21**	**5.28**

Where:

[B] Revenue was determined by each DNSP's usage tariffs and was used to find the peak and off-peak rates where:

$[B] = [\mathrm{A}] * [\mathrm{F}] + \frac{[C]*[G]+[D]*[H]}{100}$; And

[G] = [E]*[H]

For FY22 and FY26, the indicative network use of system ('NUOS') charge for the applicable ToU and demand tariff from each TSS was used and the selected tariffs can be seen in Table. Given that indicative tariffs for FY29 are not available, the FY26 tariffs were applied to the FY29 cost stack.

Table 7 Summary of tariff Selection

DNSP	2018		FY22, FY26 and FY29	
	Time of Use	Demand	Time of Use (default)	Demand
AusNet	Calculated value	NASN11	NAST11	NASN11
Citipower	Calculated value	CR	CRTOU	CR
Jemena	Calculated value	A10D	A120	A10D
Powercor	Calculated value	DD	PRTOU	DD
United Energy	Calculated value	RESKW1R	URTOU	RESKW1R

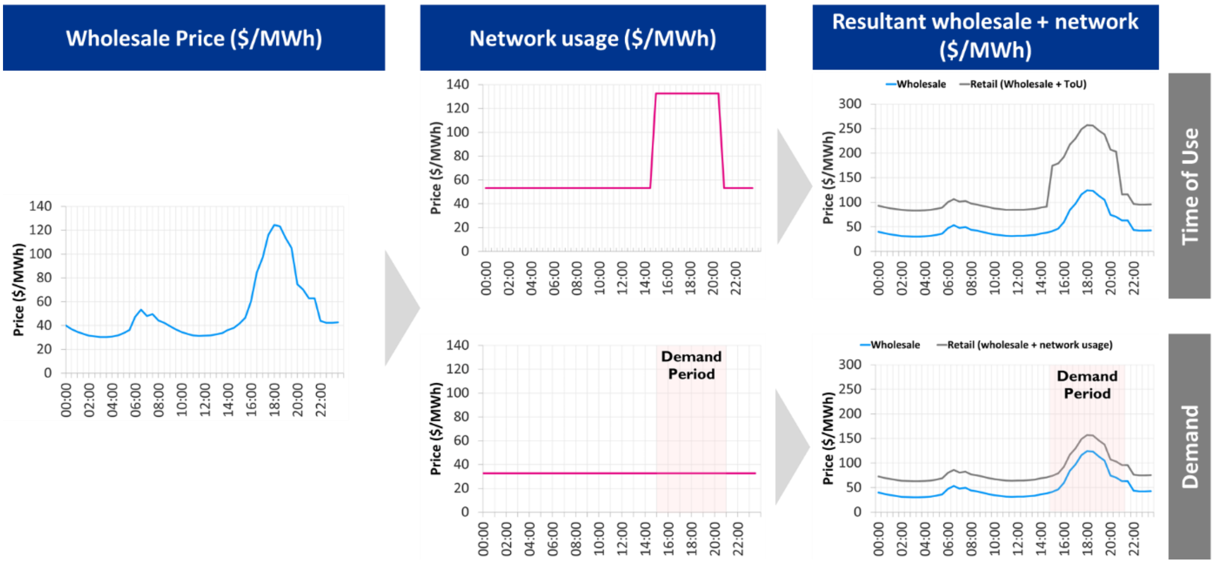
4.2.4 Retail Prices

The retail price[37] used for the modelling was derived by combining the wholesale and network prices together. Figure 18 is an illustration of the retail stack where the top graphs represent ToU tariffs while the bottom graphs depict demand-based tariffs. The ToU tariffs have a higher variation in retail prices during the evening period while the demand tariffs have flatter usage charges with costs highly dependent on usage during the shaded demand period.

It is worth noting that our retail price profile does not correspond to any observed retail tariffs, since we add network tariffs with wholesale spot prices to derive our retail price. In contrast, actual retail tariffs are typically based on wholesale *contract* prices and so have a smoother profile. This said, it is worth noting the growing amount of wholesale spot price-exposed retail tariffs, such as those offered by Amber Electric.[38]

[37] Retail price shown is wholesale and network price component only, as this has been the focus of this study. It does not include network losses, environmental charges, retailer costs, controlled loads and hedging costs.
[38] https://www.amberelectric.com.au/pricing

Figure 18 Illustrated derivation of final retail stack for FY22 with United Energy as DNSP



4.3 Managed Profiles

The managed profiles were derived by using the same assets used for the unmanaged case, but with their flexibility optimised against the cost stack through an optimisation model. The asset availability and flexibility can be seen in Table 8 below, where the specification and flexibility of each asset has been based on common examples seen in market, rather than based on the optimised values under the current retail tariffs.

Table 8 Managed profile Asset availability

	DER Asset Specification	Asset Availability
PV + BESS	5kW PV, 5kW/13.5kWh BESS Roundtrip efficiency = 90%[39]	BESS can charge from the grid and export to the grid.
EV	7.4kW/50kWh EV battery[40] Roundtrip efficiency = 85%[41] Minimum state of charge = 10kWh	Vehicle assumed to be available only from 5pm to 7am.

[39] In line with a common BESS such as a Tesla powerwall2

[40] Based on a Tesla Model 3 that had a single phase charger. It was assumed that the example customer will not upgrade the supply connections to a three phase input to accommodate a large EV charger given limited performance variations between single and three-phase chargers

[41] Based on study of electric vehicles and V2G integration by Future grids by Daniel O'Neill, Baran Yildiz, and Jose I. Bilbao, SPREE UNSW.

PV + EV	5kW PV, 7.4kW/50kWh EV battery Roundtrip efficiency = 85% Minimum state of charge = 10kWh	Vehicle arrives home with 85% charge assuming that the EV will require 7kWh of charge as in the unmanaged case which have a range of 45-60km. EV must be fully charged by 7am. The EV must always have a minimum charge of 10kWh which would be representative of 40-55km in range. For the PV + EV case, the EV may be charged by any excess energy generated by the PV from 5pm onwards.
Pool Pump	2,240 kWh/year 1 kW max draw	Single speed devices that can be turned on or off resulting in the pump either consuming 1 kW per hour when on or being turned off.
HVAC	HVAC load set according to profile, with maximum of 1.7kWh in a 30 min period (broadly in line with a 10-14kW HVAC system)	Available for load shedding of 2 hours[42] a day for a maximum of 5 days a year[43].

The managed assets are assumed to access the FCAS markets, where bid volumes are based on the charge stage (+/- MW) and available energy after wholesale arbitrage for every half-hour period to calculate the FCAS availability and participation volumes, as outlined in section 4.2.

[42] Based on current Energy Queensland demand response mechanism which showed minimal variation in customer comfort with two hours of HVAC reductions.

[43] We reviewed the value of demand response ('DR') against the number of days of DR to find that there isn't a significant increase in the value increasing of DR by increasing the number of days, indicating that most value is found in the 5 peak energy days.

5 Operational Behaviour

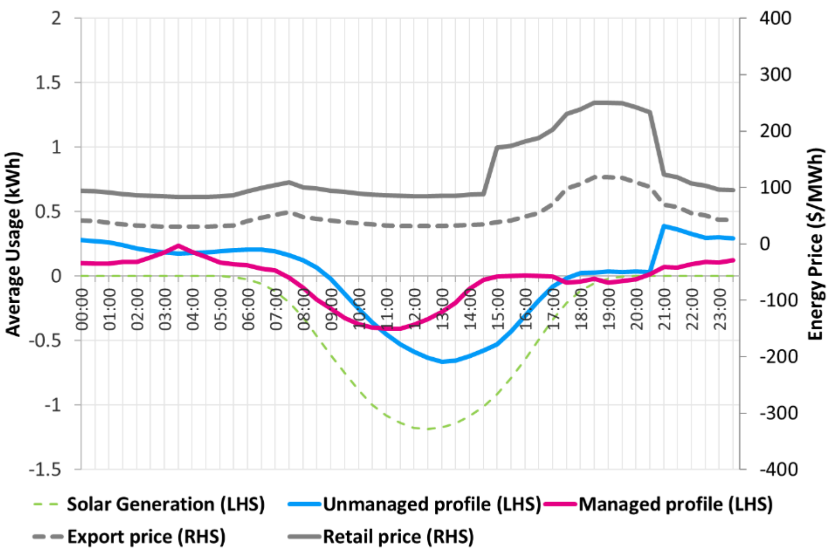
In this section of the report, we provide an overview of the operational behaviour of the assets. We review the flexibility shown by each asset along with key drivers for its operation including the impact of network prices. For simplicity of reporting and comprehension, the charts in the following section are for United Energy DNSP and FY22.

5.1 PV + BESS

In the managed scenario, the BESS utilises more of the energy from the PV and reduces both export and grid consumption for the household. The BESS typically discharges between 3-9pm to reduce energy consumption from the grid during peak network periods, while ensuring that the demand is zero during these periods for customers on a demand tariff. The BESS utilizes the PV more than it does in the unmanaged case, resulting in less energy consumption from the grid over the year and less export of excess energy from the PV to the grid as seen in Figure 19. While not a focus of this study or explicitly modelled, the level of curtailment (should the PV start getting curtailed in the future) would reduce as the PV exports less energy due to increased utilisation by the BESS.

It has been assumed that any net export from the household will be valued at the wholesale price, represented by the dotted grey lines in the following charts. Any reduction of customer import from the grid will be valued at the retailer price which is the combined wholesale and network tariff.[44]

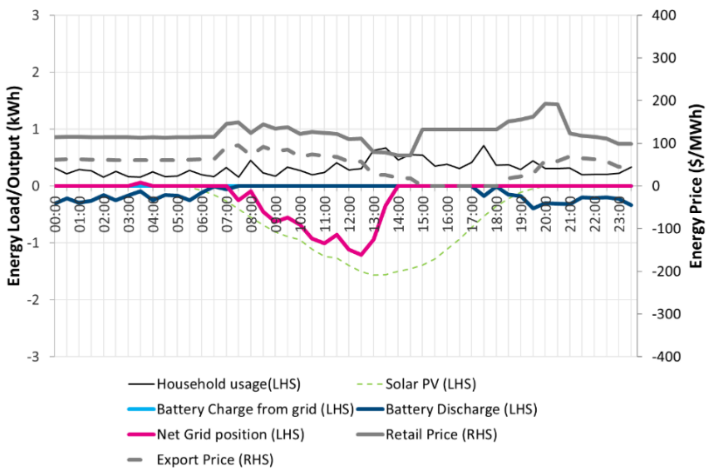
Figure 19 Average daily energy consumption across all days for PV+BESS[45]



[44] For this modelling, the avoided distribution system network losses have not been considered. These would vary depending on the customer site distribution loss factor (DLF), but would typically add around 5% to the wholesale value but could range between 0.4% to 10% across the Victorian DNSPs (based on AEMO's DLF value for the Victorian distributors in 2019/20).
[45] Retail price shown is wholesale and network price component only, as this has been the focus of this study. It does not include network losses, environmental charges, retailer costs, controlled loads and hedging costs.

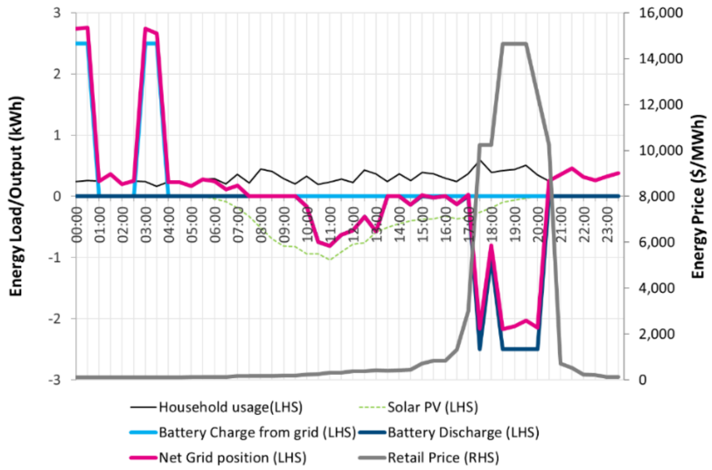
On a typical day, the BESS does not export energy but meets the household energy load. In Figure 20, the BESS does not charge from the grid and does not export to the grid as the PV charges the BESS and discharges only to meet the household energy requirement, as the export price does not exceed the retail price.

Figure 20 PV + BESS operation on a typical day[46]



On a high price day, the BESS would typically export during the evening high price periods. In the high price example in Figure 21, the BESS exports during the afternoon peak when wholesale prices exceed $2,000 and reaches its minimum state of charge by 8pm, after which the household consumes energy from the grid. In this scenario, the export price in the afternoon period is considerably higher than the retail price post 8pm, resulting in the BESS choosing to export all its energy before 8pm instead of dispatching during the 8-9pm peak network price period.

Figure 21 PV + BESS Operation on a high price day[47]



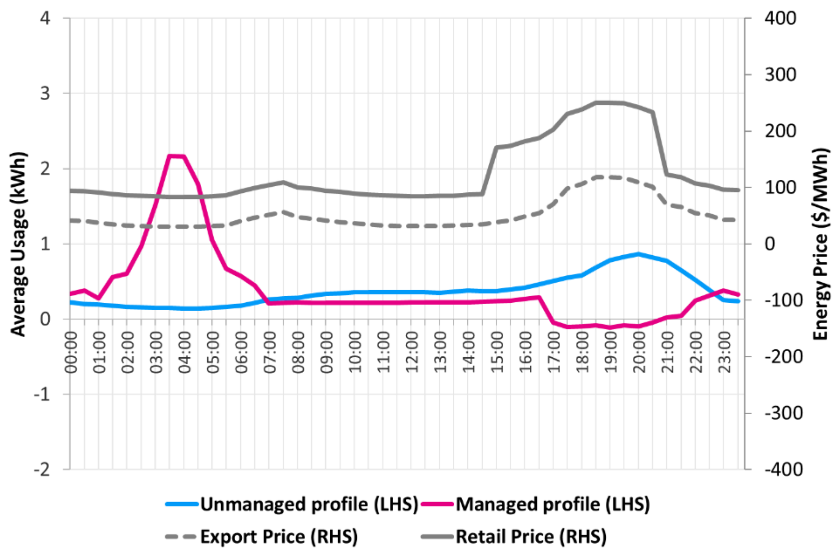
[46] Retail price shown is wholesale and network price component only, as this has been the focus of this study. It does not include network losses, environmental charges, retailer costs, controlled loads and hedging costs.
[47] Retail price shown is wholesale and network price component only, as this has been the focus of this study. It does not include network losses, environmental charges, retailer costs, controlled loads and hedging costs.

5.1.1 EV

The managed EV typically comes home in the evenings less than fully discharged from its day trips, provides energy to the household during the evening peak period, and charges overnight. The EV operates in a similar manner to the regular BESS and is considerably larger than the household energy requirement. This modelling assumes at-home charging only, and that the EV is not at the property during the middle of the day. For customers with different usage patterns, such as shift workers or retirees, the charging windows may be materially different, and provide access to charging during low price periods in the middle of the day. Equally, if public charging infrastructure is deployed extensively and tariffs evolve to allow households to capture value from charging in the middle of the day, value may be improved.

As seen in Figure 22, the EV is large enough to meet the household's energy consumption and typically discharges between 5-9pm. Any additional discharging and exporting to the grid then depends on prevailing wholesale spot prices. The EV charges overnight, with the volume of charge dependent on the previous day's discharge profile. The profile in the graph below is based on an annual average and will vary on a day by day basis.

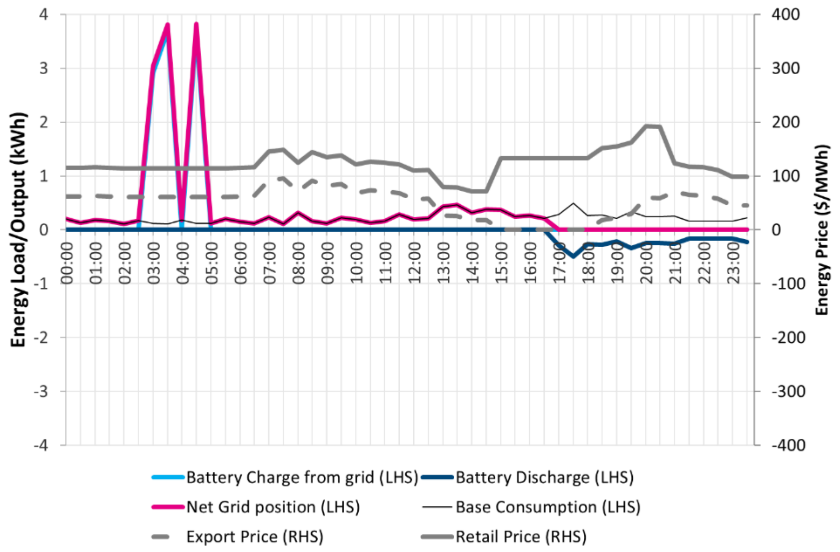
Figure 22 Average daily energy consumption across all days for an EV[48]



On a typical day, the EV is large enough to meet household energy requirements through the evening peak period and charges overnight during periods of low prices. The EV does not typically supply energy to the household during off-peak hours as any energy discharged will need to be charged back to ensure that the EV is fully charged by 7am.

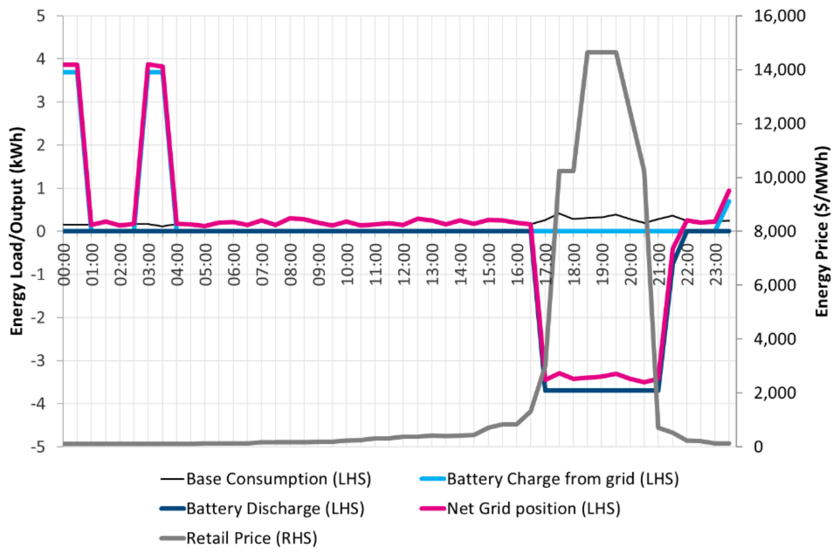
[48] Retail price shown is wholesale and network price component only, as this has been the focus of this study. It does not include network losses, environmental charges, retailer costs, controlled loads and hedging costs.

Figure 23 EV operations on a typical day



On a high price day, the EV would discharge during the high price afternoon peak in a similar manner to the PV + BESS. However, the duration of an EV is longer than 4 hours as it arrives home with ~43kWh and has a minimum state of charge of 10kWh, resulting in the EV having ~33kWh which is more than 4 hours of discharge at its 7.4 kW capacity. The longer duration of the EV allows it to discharge for a longer duration of the peak period as seen in Figure 24.

Figure 24 Typical high price day discharge behaviour[49]

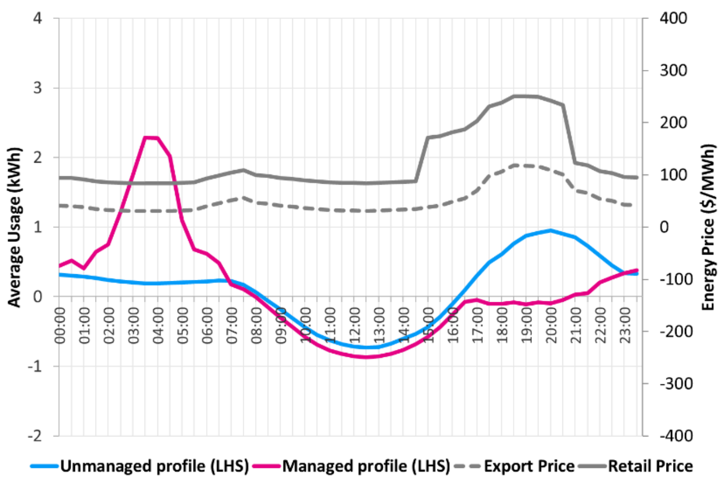


[49] Retail price shown is wholesale and network price component only, as this has been the focus of this study. It does not include network losses, environmental charges, retailer costs, controlled loads and hedging costs.

5.1.2 PV + EV

The managed PV + EV operates in a similar manner to the managed EV, with the only difference being the availability of the PV to meet household demand and charge the EV. The daytime profile (from 7am to 5pm) of a managed PV + EV is similar to the unmanaged profile. The operation of the EV is similar to operation of an EV with no PV, but the only difference is the availability of additional solar energy to meet household demand or charge the BESS after 5pm.

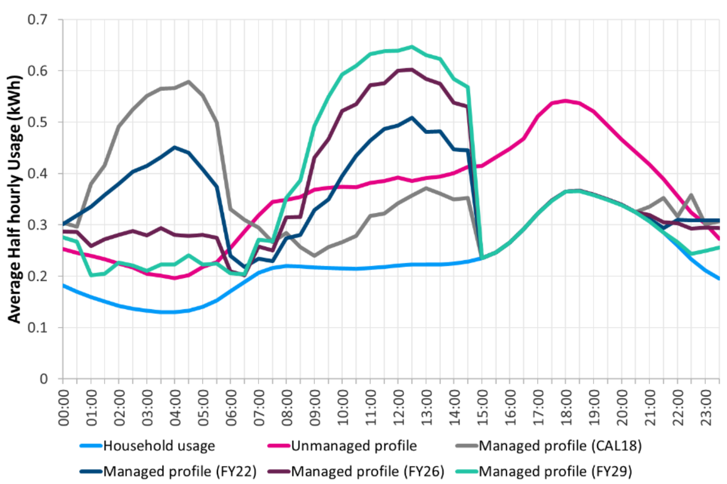
Figure 25 Average daily energy consumption for PV + EV[50]



5.1.3 Pool

The managed pool pump was operated in a flexible manner where it ran for just over six hours every day during the lowest prices periods. This resulted in varying profiles each year as seen in Figure 26.

Figure 26 Comparison of managed pool profile by year (United Energy)



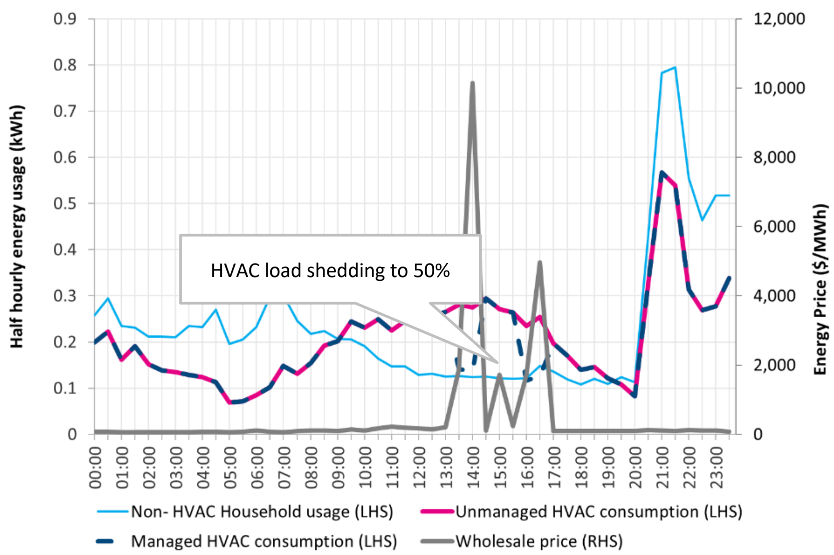
[50] Retail price shown is wholesale and network price component only, as this has been the focus of this study. It does not include network losses, environmental charges, retailer costs, controlled loads and hedging costs.

The pool pump usage moved from being operating predominantly overnight in CAL18 to operating during the middle of the day in FY29 due to the varying price shape, which is driven by the sharp increase of solar generation on the grid. The pool pump does not operate during the peak network and peak demand periods in any year.

5.1.4 HVAC

The managed HVAC profile offered little variation to the average daily shape as it resulted in load shedding of HVAC demand to half its output for 2 hours a day for 5 days. Figure 27 is a representation of load shedding on a day of high prices where the managed HVAC load reduces to 50% of the unmanaged case.

Figure 27 HVAC load shedding on day of high prices



5.2 FCAS operations

The charge state (+/- MW) and available energy after wholesale arbitrage for every half-hour period was used to calculate the FCAS availability and participation volumes. FCAS participation was optimized according to the following rules:

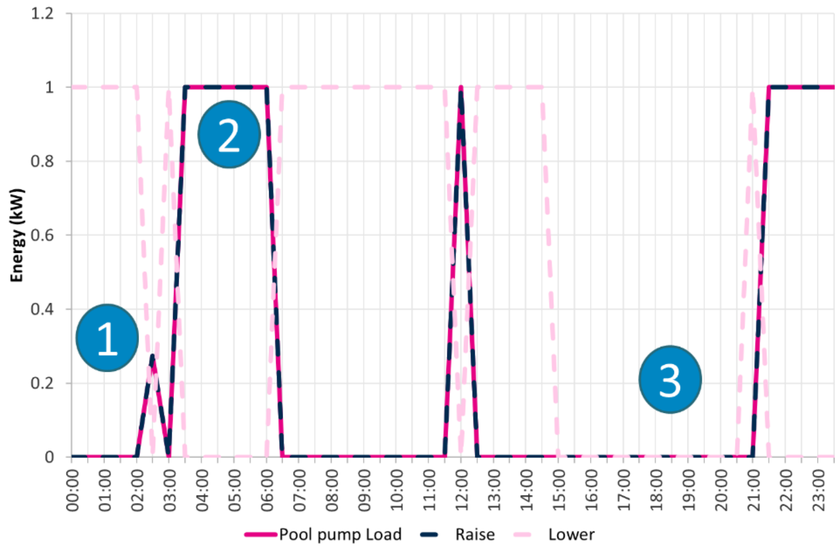
- **Contingency FCAS bidding strategy:** It was assumed that the BESS participates in Contingency FCAS Raise services at all times, and Contingency FCAS Lower services only during off-peak hours. This assumption helps determine the state-of-charge of the BESS at any time of the day.
- **Mutual exclusivity with energy arbitrage:** Projections for the DER asset have been constrained by its participation in energy arbitrage. The asset is unable to provide Raise services when dispatching at full capacity, and unable to provide Lower services when

charging at zero capacity (i.e. mutual participation is power limited). Additionally, for the PV + BESS, the asset is unable to provide Lower services when the PV is charging the BESS.

FCAS revenues were reduced slightly to account for the cost incurred to bring the asset back to its state of charge after being called upon to provide FCAS services. FCAS revenues were further discounted to account for a conservative view of the correlation between high FCAS prices and high wholesale prices.

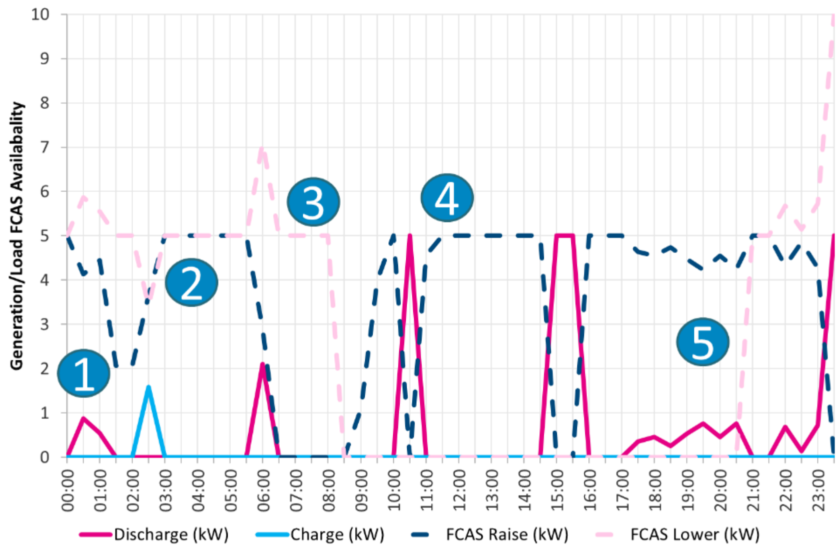
Figure 28 and Figure 29 illustrate the FCAS bidding behavior and resulting FCAS trapezium of a pool pump and PV + BESS system. A similar logic was applied to all other DER assets.

Figure 28 Illustration of FCAS bidding for a pool pump



#	Pump operation	FCAS Raise	FCAS Lower
1 (01:00 hours)	Pump off	0 kW	1 kW – *by turning on pump*
2 (05:00 hours)	Pump on	1 kW - *turn off pump*	0 kW - *cannot increase pumping*
3 (18:00 hours)	Pump off	0 kW	0 kW - *no lower during peak hours*

Figure 29 Illustration of FCAS bidding behaviour for PV + BESS



#	BESS Operation	Raise	Lower
1 (00:30 hours)	BESS discharging at 1kW	4kW - *increase discharge from 1 kw to 5kW*	6kW - *stop discharge 1 kW + charge 5kW*
2 (04:00 hours)	BESS Static not full or empty	5 kW	5 kW
3 (07:30 hours)	BESS static empty	0 kW – *no energy available to discharge*	5 kW
4 (12:00 hours)	BESS discharging 5kW (100%)	0 kW – *discharging at max level*	0 kW – *cannot change action as energy from PV is flowing into BESS*
5 (20:00 hours)	BESS discharging at 0.8 kW	4.2kW - *increase discharge from 0.8kw to 5kW*	0 kW – *no lower during peak periods*

The modelling assumed that the entire available volume may bid into the market and be enabled. FCAS bids are required to be submitted in full MW blocks which may reduce the volume being bid by each household into the market to aggregate to a whole number. This is particularly relevant for smaller portfolios, where the minimum bid size can be a large proportion of the total aggregated portfolio. As an example, under current rules, aggregated portfolios of 1-1.9MW can register and enable only 1MW of response.

5.3 Influence of network prices on operations

A secondary consideration in this study was to investigate the impact that the network tariff structure had on the operational profile of the BESS. This was considered by comparing the operation of the assets when optimised against a combined wholesale and network price signal, with the operations which would be observed if optimised against wholesale prices only.

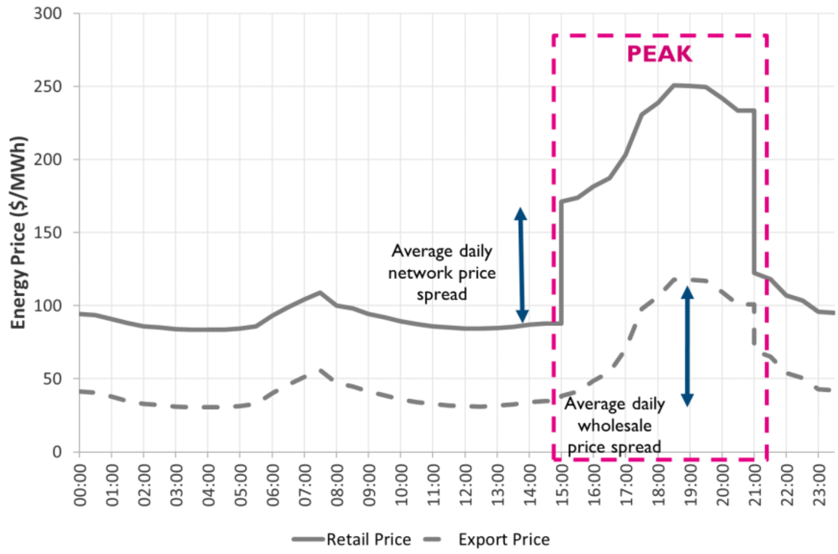
5.3.1 Impact of prices on retail price signals

The network price signals considered in this study are for a time-of-use ('ToU') tariff without any demand charges, and have the following two characteristics:

- **Static** – the price levels and time windows are determined in advance and fixed.
- **Long-run** – the tariff is determined based on a longer-term forward view of system demand and supply, consistent with distribution network pricing principles. Being a longer-run price signal, such a tariff is necessarily not expected to be reflective of short-run, real-time, changes in the supply and demand of the system.

In comparison, wholesale NEM spot prices can be thought of as dynamic short-run price signals, given they are currently set in 30-minute trading intervals based on regional supply-demand dynamics. Therefore, any differences in network price signals vis-à-vis wholesale spot prices can result in the operation of DER in ways that are not aligned with regional supply-demand dynamics (on which the operation of grid-connected batteries are based).

Figure 30 Average daily energy price shape (FY22)[51]



On average, annual spreads in wholesale prices are similar to those of network prices as seen in Figure 30. However, across days, network price spreads are greater than wholesale price spreads on a larger proportion of days (74 % in FY 22 for United Energy & 98% for AusNet) as seen in Table 9.

[51] Retail price shown is wholesale and network price component only, as this has been the focus of this study. It does not include network losses, environmental charges, retailer costs, controlled loads and hedging costs.

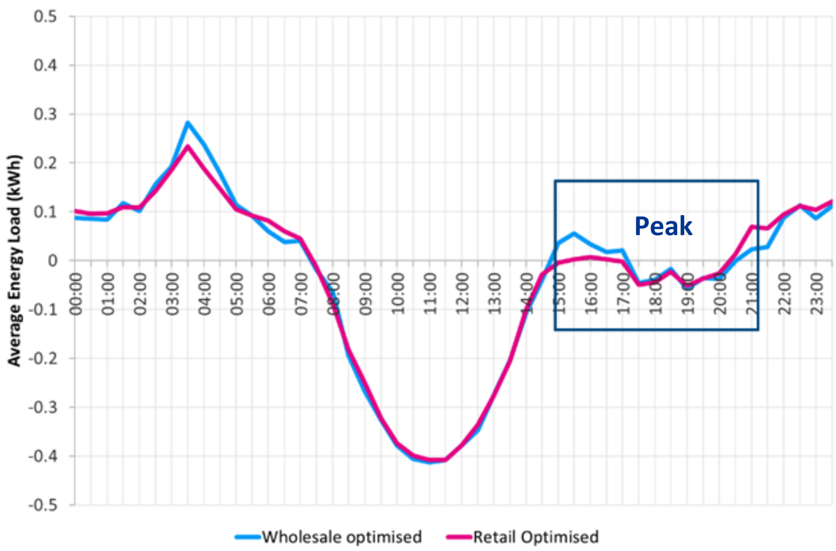
Table 9 Extent of ToU network price signals (United Energy)

	% days with largest 2 hour daily spread from…	
Year	…network	…wholesale
FY 22	74%	26%
FY 26	83%	17%
FY 29	70%	30%

The impact of network price signals increases for AusNet and Jemena, as they have higher off peak to peak price ratios of 5:1 and 3:1 respectively (when compared to the other three DNSPs whose ratios are 5:2).

Network prices influence timing of dispatch for managed DER, but dispatch behaviour is typically well-aligned between wholesale and network price signals. As shown in Figure 31 below, behaviour is similar when assets are optimised against wholesale prices only. The small wholesale uplift in value illustrates that when optimising against wholesale and network prices, the DER asset tends not to charge during the peak demand window, and discharges less from 9-10 pm than it would otherwise. This suggests that while the peak network price window is typically well-aligned to the peak wholesale price periods, there are some days in which wholesale prices peak slightly later than would be captured within the network peak period.

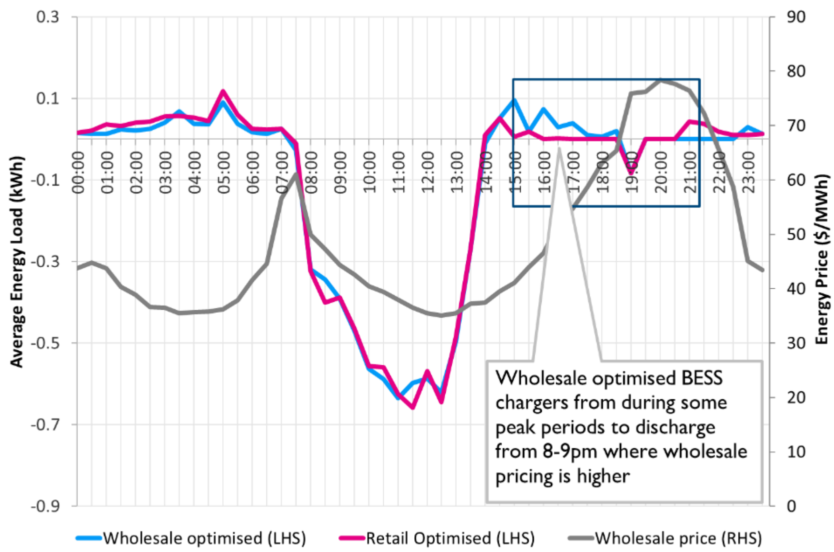
Figure 31 Comparison of BESS operation through retail versus wholesale-only cost optimisation for FY22



There are a few periods where the BESS receives conflicting price signals from the wholesale and network prices. For example it was found that the BESS wholesale arbitrage revenue would increase by 3-5% when optimized against the wholesale price rather than the retail price (wholesale + network price).

The existence of static network prices forces the BESS to discharge (or not charge) between 3-9pm even during periods of low wholesale energy prices. In the sample month of Feb 2022, the BESS would charge during the early network peak periods, on days of low prices, if there were no network charges as seen in Figure 32. However a behind-the-meter BESS will not be able to do so as network charges during this period would add $150-$250/MWh to the cost of charging.

Figure 32 Average consumption and dispatch profile for summer month (Feb 2022) through retail versus wholesale-only cost optimisation



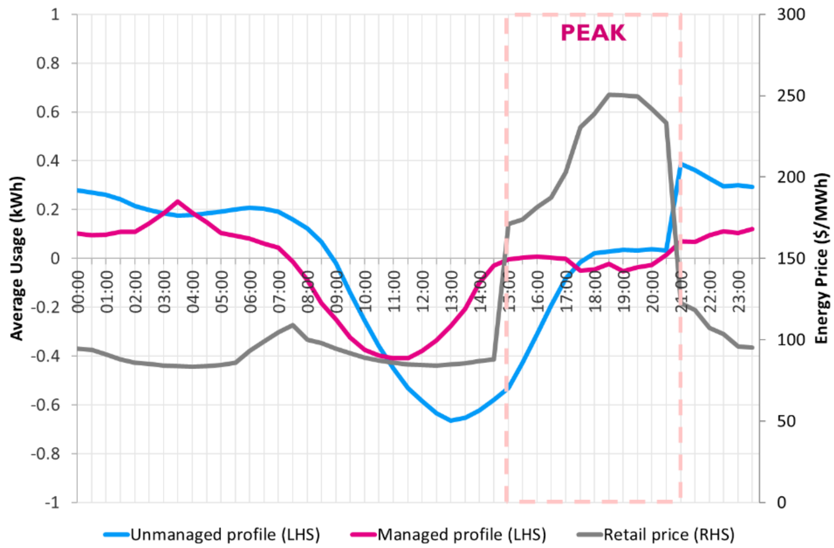
On average (except in 2018) the wholesale energy price is higher from 8-9pm when compared to 3-4pm showing the peak wholesale and network periods are not perfectly aligned. This variation may be more accurately captured with dynamic network price signals.

5.3.2 Impact of network prices on dispatch

Managed assets, optimised against the full retail granularity, show greater daily variability in their operations when compared to the unmanaged asset.

The unmanaged PV + BESS is assumed to operate with a simple dispatch logic, against a retail tariff only. It is set to charge from PV and discharge to meet household energy consumption during the evening peak retail period, providing a consistent daily shape. In comparison, for the managed case, the BESS may charge from the grid when prices are low or export power during high wholesale price periods.

Figure 33 Comparison of average dispatch profile of managed and unmanaged PV + BESS[52]



The BESS studied and being installed by households currently are larger than a typical household's energy needs, so can discharge to meet the household's load through the entire evening peak. This avoids a potential 'cliff edge' of significant demand increases at the end of the peak network period, as seen in Figure 20 above. Once the BESS dispatches through the peak network period the remaining energy's dispatch is driven by wholesale prices. This means there is less consistency between daily discharge patterns.

However, when market conditions result in less energy being available for the evening peak, through either export of energy during high price periods or reduced generation from the PV, the peak network price becomes the dominant price signal. When the BESS is energy constrained, the dispatch would typically align to the peak network times and potentially cause a 9pm cliff edge – as seen in Figure 21 where the BESS dispatches until 9pm after which the household consumes energy from the grid.

[52] Retail price shown is wholesale and network price component only, as this has been the focus of this study. It does not include network losses, environmental charges, retailer costs, controlled loads and hedging costs.

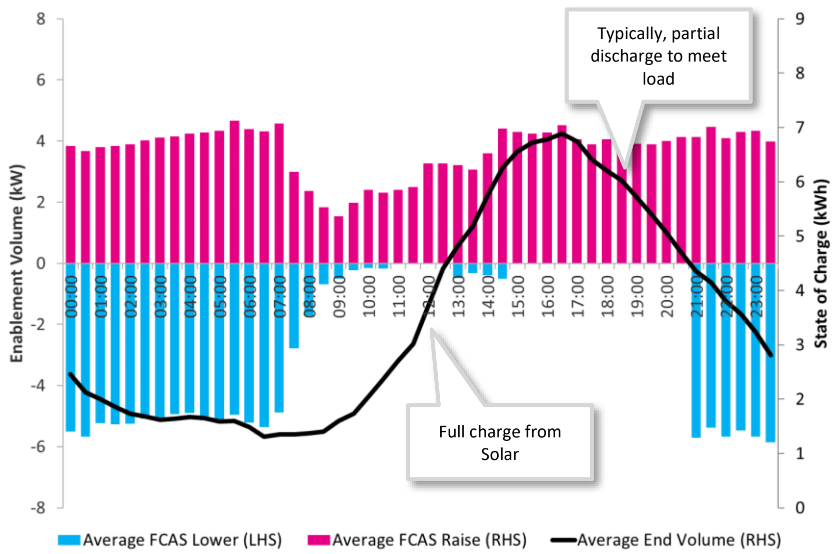
5.3.3 Impact of network prices on FCAS revenues

Network price periods have a smaller impact on availability for FCAS revenues, with reduced FCAS availability driven largely by high wholesale price periods. It was found that the BESS FCAS revenue would increase by only 2% when optimized against the wholesale price rather than the retail price. (wholesale + network price).

For the PV + BESS system, availability for Raise Contingency FCAS is fairly constant over the day. Network price periods have limited impact on the enablement profile for FCAS. This is due to the fact that the BESS is large (5kW, 13.5kWh) compared to average house loads (peak of 3.5kW), so when the BESS is discharging to meet residential load, it can frequently still increase its discharge to provide Raise FCAS.

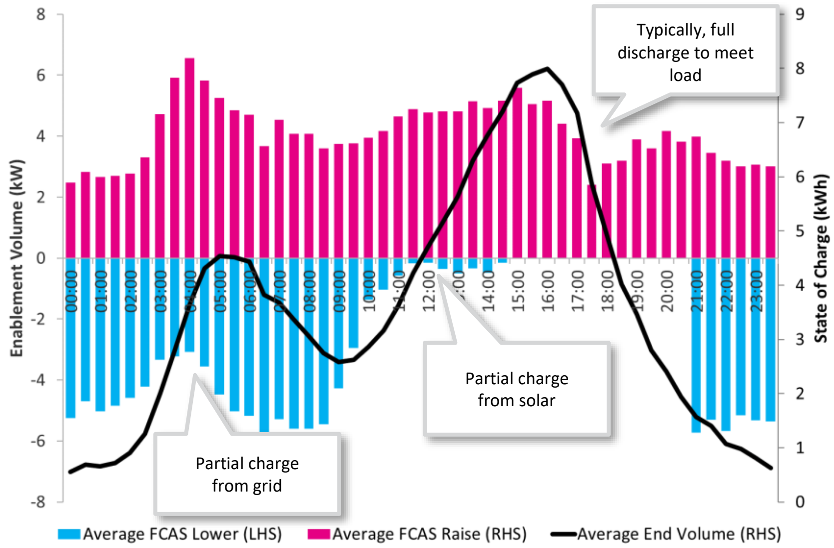
On the majority of days in all months, the BESS discharges to meet the household consumption. The asset exports only if wholesale price spreads are large. In summer, generation from the PV coincides with peak consumption and therefore less discharge (kW) is required to meet customer load, and more is available to provide FCAS raise through the peak period. This is illustrated by the slower reduction in average state of charge in Figure 34 below.

Figure 34 FCAS enablement - January 2018



In winter, a greater BESS capacity is required to meet customer load at peak times, meaning the availability to provide FCAS is limited during peak times. Availability to provide lower services is also limited during the morning charge as the BESS draws from the grid.

Figure 35 FCAS enablement - July 2018



It has been assumed for all profiles that lower services are not offered during peak network hours, or when the BESS is charging from PV. This reduces Lower enablement volumes in the middle of the day, particularly in summer. Further Lower enablement volumes may be able to be achieved, but given the low value of FCAS Contingency Lower services the impact on total value is low.

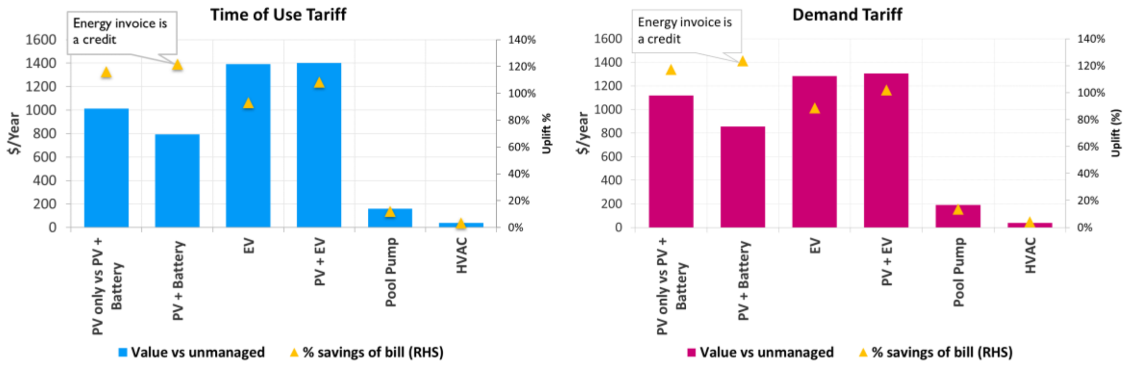
6 Results

6.1 Summary

This study finds that there is an annual value[53] potential for residential customers with large flexible DER assets including batteries and EVs. For example, in FY 2022 this value is in the order of $800-$1400 pa. This represents savings of 90%-105% of the total retail bill for customers with EVs and PV + EVs and more than a 120% reduction for customers with PV + BESS assets. Savings of more than 100% results in the total retail bill being a credit back to the household. The value of PV + BESS against a household with just a PV system and no BESS is between $1,000-$1,100/year in FY22, showing the value of the BESS to be between $1,000 and $1,100 for that year.

The value for managed flexibility of pool pumps is significantly lower at $180-200/MWh, or 18%-20% of total wholesale and network costs, due to the limited amount of flexibility and high number of running hours required per day. The value of managed flexibility for HVAC is less than $50/year due to its infrequent operation.

Figure 36 Value of managed profiles vs unmanaged profiles in FY22 (Average across all DNSPs)



All values shown should be considered illustrative of a theoretical maximum value achievable for the technical parameters modelled and only includes wholesale cost savings, network cost savings and FCAS revenues. This is because the modelling has been done on a 'perfect-foresight' basis (i.e. the optimiser has perfect forecasting of price) and assuming 100% availability of DER assets when at the residential property. In addition, each asset is modelled as a 'price taker' in the market, meaning the actions of the DER asset does not influence prices in the market. The impact of this is considered further in section 7.

Similar levels of value for managed flexibility are seen for ToU and demand network tariffs for customers with storage assets, whether home battery or within the EV. This is a result of the assets being sufficiently large to reduce the household consumption to zero through the ToU or demand peak period, which is from 3-9pm.

[53] Value is based on reduction of bill through wholesale and network costs plus revenue earned through ancillary services for a single household. It does not include any capital or operational costs for the DER asset.

For simplicity of reporting and comprehension, the charts in the following section are for United Energy DNSP. This was chosen as it has an average peak / off-peak spread compared with the other DNSPs in the group. Further consideration of differences between DNSPs is outlined in Section 0.

6.2 Results by Asset Type

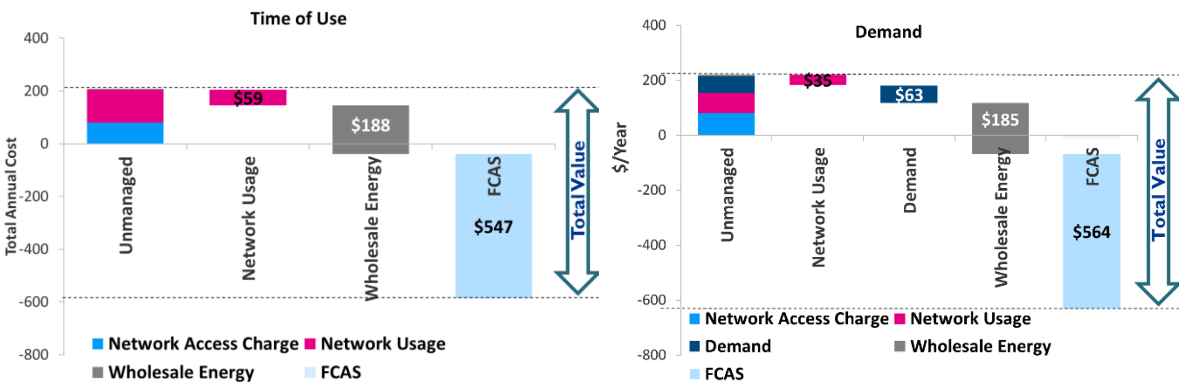
6.2.1 PV + BESS

In the managed scenario, the BESS maximizes the amount of energy it receives from the PV during the day and reduces consumption from the grid during the evening peak period.

For the managed scenarios, both ToU and demand tariffs have similar total costs[54] for the customer. The value of managed flexibility is higher for demand tariffs as the unmanaged demand tariff is more expensive than the unmanaged ToU tariff. The BESS eliminates all demand charges for a demand tariff by ensuring that the PV + BESS dispatch meets or exceeds household energy demand from 3-9pm thereby eliminating grid demand during this period.

FCAS revenue is significant for both tariff structures, with an average enablement volume of 3.7kW for each of the Raise Contingency FCAS products (6s, 60s and 5 minute), and 2.5kW for each of the Lower Contingency FCAS products (6s, 60s and 5 minute) over the year. As discussed in section 7, realized FCAS value may be significantly below the potential value shown here due to the requirement to commit to explicit FCAS response ahead of time.

Figure 37 Value of managed flexibility for each component of the cost stack - United Energy (FY22)



Total Value - $794 **Total Value - $847**

The wholesale energy cost for an unmanaged for PV + BESS is approximately $0 as seen Figure 37. The excess energy from the PV is exported to the grid offsetting any grid consumption costs.

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[54] Total cost is considered the total wholesale and network costs, plus the FCAS revenue for the managed profile. The cost of managing the state of charge after a Contingency FCAS event has not been considered in this study, given its small magnitude compared with uncertainty on available and enabled FCAS volumes.

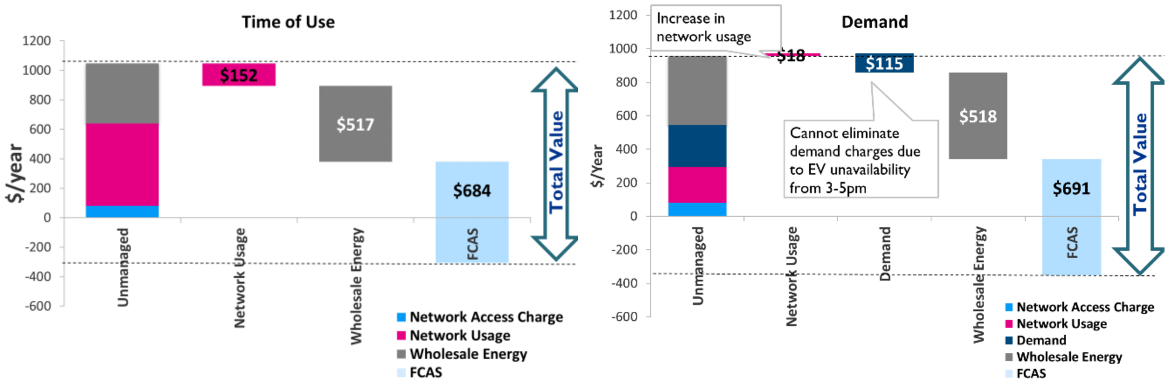
6.2.2 EV & PV + EV

For a managed profile, both demand and ToU tariffs result in similar total cost[55] to a customer. The value of managed flexibility is higher for ToU tariffs as the unmanaged ToU tariff is more expensive than the unmanaged demand tariff.

For a demand tariff, the demand charges cannot be completely eliminated as the EV is unavailable to meet household demand from 3-5pm. The network usage charges for a demand tariff increases as the EV consumes more energy, due to its V2G and V2H capabilities, when compared to an unmanaged case.

Potential FCAS revenue is significant for both tariff structures, representing an average enablement volume of 4.8kW for Raise products (6s, 60s and 5 minute) and 1.7 kW for Lower products (6s, 60s and 5 minute) over the year.

Figure 38 Value of managed flexibility for each component of the cost stack for EV – United Energy (FY22)

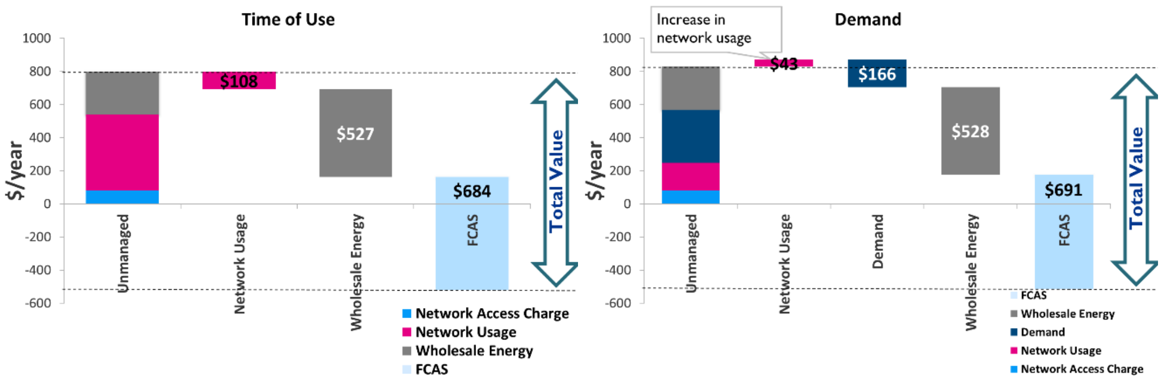


Total Value - $1,353 **Total Value - $1,306**

For the PV + EV, the value of managed flexibility for each component of the cost stack is similar to the EV as the operation of the assets are similar. The PV offsets household energy consumption during the day for both the managed and the unmanaged profiles.

55 As in footnote 16, total cost is considered the total wholesale and network costs, plus the FCAS revenue for the managed profile.

Figure 39 Value of managed flexibility for each component of the cost stack for PV + EV - United Energy (FY22)



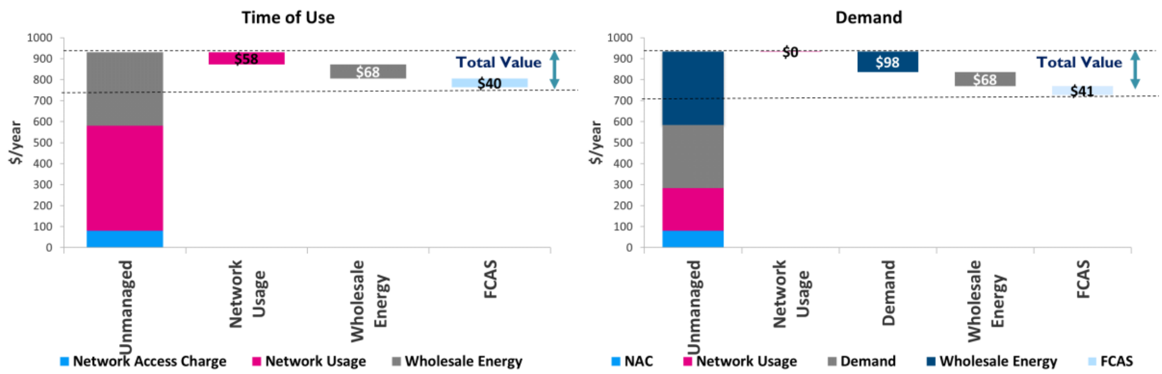
Total Value - $1,319 **Total Value - $1,342**

6.2.3 Pool

For the household with the unmanaged pool profile, the cost of demand and ToU tariffs is identical. The wholesale + network costs for a managed pool profile is 15-20% lower than for the unmanaged profile. The demand tariff offers marginally better value for managed flexibility for typical households.

FCAS is offered as a binary function dependant on the operation of the pump. FCAS provides additional annual value of approximately $40.

Figure 40 Value of managed flexibility for each component of the cost stack for Pool – United Energy (FY22)

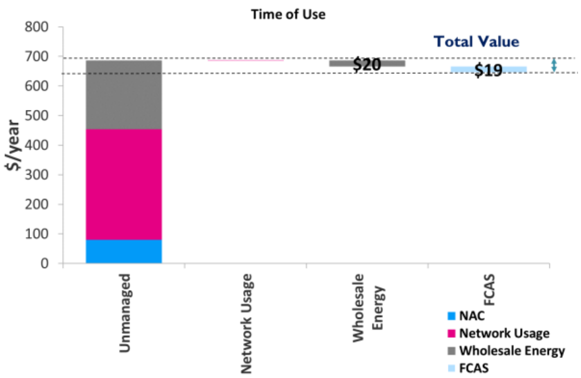


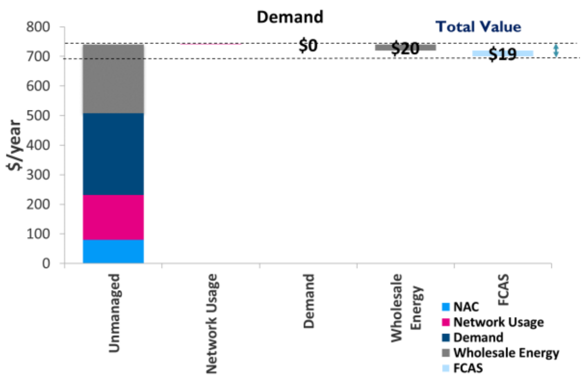
Total Value - $166 **Total Value - $207**

6.2.4 HVAC

The wholesale + network costs for managed HVAC profile is 3% lower than for the unmanaged profile with value coming through load shedding and participation in the FCAS markets. For the unmanaged case, demand tariffs are more expensive due to the spikey nature of HVAC. The value across both ToU and demand tariffs are almost identical as the tariff does not impact the demand response mechanism while the infrequent nature of the response does not reduce network costs.

Figure 41 Value of managed flexibility for each component of the cost stack for HVAC - United Energy (FY22)





Total Value - $39 **Total Value - $39**

6.3 Results by DNSP

6.3.1 Comparison of value

The value of managed flexibility is similar across all DNSPs for households with PV + BESS assets, pools and HVAC as seen in Figure 42. Similarly, the value does not vary considerably between ToU and demand tariffs for these assets.

When looking at ToU tariffs for EVs and PV + EVs, the value of managed flexibility is higher for AusNet when compared to other DNSPs due to its higher off-peak to peak price ratio. This makes load shifting more valuable for AusNet customers. For EV and PV + EV asset classes, ToU tariffs offer marginally more value given that all demand charges cannot be completely eliminated due to the unavailability of the EV between 3-5pm.

Figure 42 Value of management by DNSP - FY22

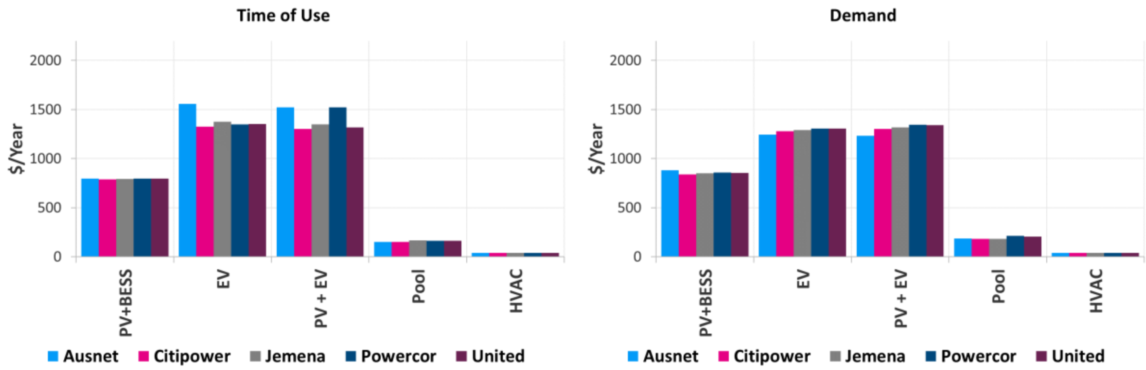
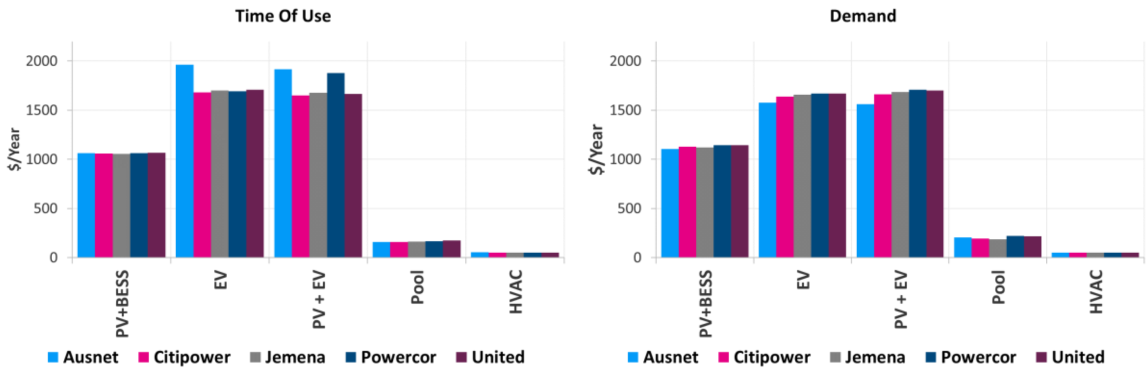
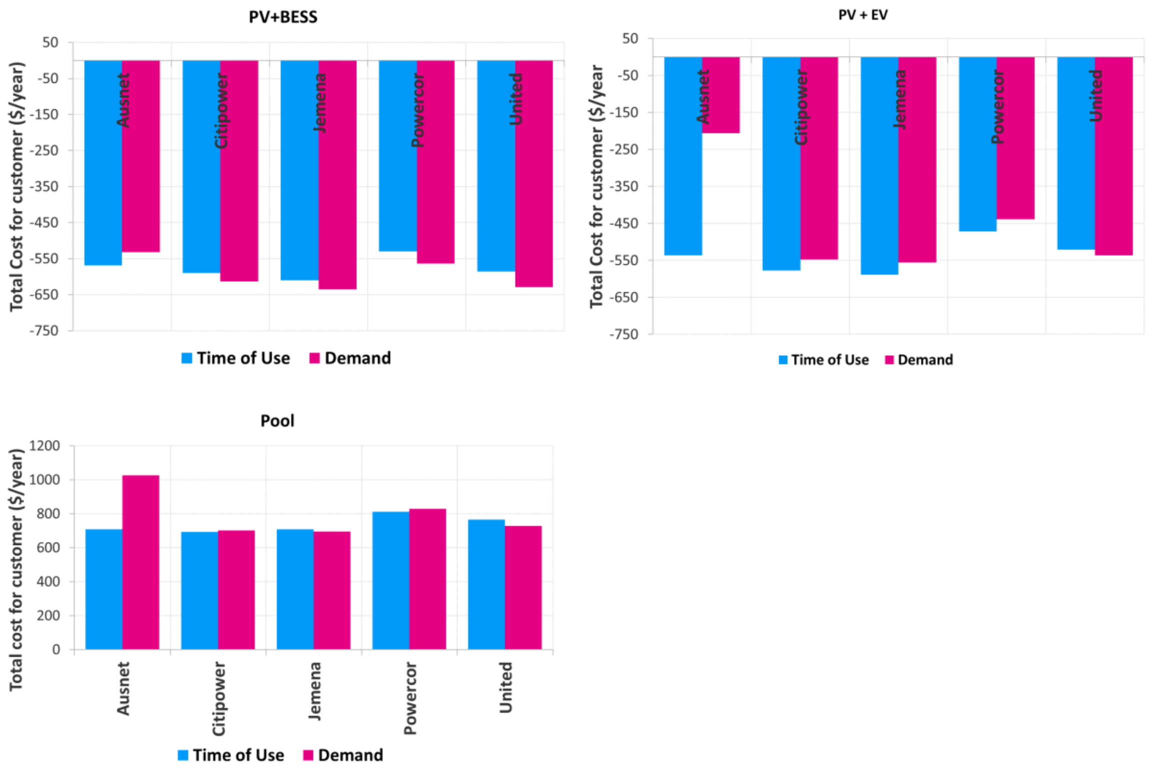


Figure 43 Value of management by DNSP - FY26



In general, both demand and ToU tariffs have similar costs across all DNSPs except AusNet, as seen in Figure 44 below. The AusNet flat usage rate (c/kWh) for its demand tariff is considerably higher than its off-peak rate for a ToU tariff, making overnight usage considerably more expensive for sites on a demand tariff. This is not the case for other DNSPs where the flat usage rate of a demand tariff is considerably lower than the off-peak TOU rate.

Figure 44 Comparison of total wholesale and network cost/revenue by tariff type for each DNSP – FY22



6.4 Results by year

The value of managed flexibility is strongly influenced by the wholesale price spreads. Table 10 below shows FY22 to have the least value with all other years having more value due to larger wholesale price spreads. The assets with storage, such as PV + BESS, EV and PV + EV, have a greater variation in value between the modelled years due to their ability to not only load shift but also take advantage of high price events by exporting during these periods.

In general, both FY26 and FY29 have similar levels of total value for managed flexibility. The wholesale and network arbitrage value for managed flexibility is higher for FY29 due to higher wholesale price spreads. Prices for FCAS Raise product reduce in the future years and this reduces total FCAS value in FY29 when compared to FY26. However, for the typical customers with EVs, this reduction is outweighed by increased wholesale value.

For the PV + BESS example, FY29 provides higher wholesale and network value (10%) when compared to FY26. However, the PV + BESS cycles more in FY29 which leads to decrease in the volume of FCAS bid into the contingency markets. This reduced volume (5%) coupled with lower FCAS prices (5%) results in the total value of managed flexibility for PV+BESS being marginally lower for FY29 than FY26. The optimisation algorithm could be modified further to reduce cycling and potentially increase total revenues.

High price years such as CAL18 and FY29 provide the most value for pools which have the ability to only load shift and offer only binary (on/off) FCAS services.

Table 10 Average value of managed DER by modelled year ($/year)

	CAL18		FY22		FY26		FY29	
	ToU	Demand	ToU	Demand	ToU	Demand	ToU	Demand
PV + BESS	$1,237	$1,297	$794	$857	$1,062	$1,128	$1,003	$1,109
EV	$1,771	$1,670	$1,393	$1,285	$1,749	$1,642	$1,758	$1,657
PV + EV	$1,788	$1,694	$1,403	$1,309	$1,758	$1,663	$1,769	$1,674
Pool	$231	$266	$159	$194	$164	$205	$172	$212
HVAC	$52	$52	$40	$39	$53	$52	$52	$52

7 Commercial considerations

This section of the report considers what aspects may reduce expected DER asset gross margins from the modelled values, and how this value may be shared with the customer under emerging product designs.

7.1 Value capture

The values presented in this study are calculated on a perfect foresight basis, for individual customer types. Perfect foresight means the party optimising the assets is assumed to have the ability to accurately predict prices and that the DER assets are always available within the parameters assumed. Another assumption is that the DER asset is a price taker where the DER assets will not influence energy prices and will receive the prevailing market price. For these reasons, the estimated savings from DER assets should be considered as an upper bound, under the market (i.e. price) and technical conditions modelled, with discounts applied to account for imperfect price forecasting, asset availability, and transient market power.

The numbers presented are gross margins, and do not include costs for managed flexibility such as the up-front capital cost or ongoing operational costs of control hardware or software.

7.1.1 Price forecasting error

Perfect foresight of pricing has been assumed, with dispatch decisions prioritised to maximise wholesale and network price savings. With dynamic pricing signals (i.e. wholesale and FCAS prices) sophisticated price forecasting is required to fully optimise the dispatch of the DER assets. The proportion of perfect foresight value captured for a given available asset will vary depending on the sophistication of the optimisation solution and the market conditions, in particular pricing volatility. From our market due diligence work, we understand that the available battery storage technology operating in the NEM currently can capture around 75%-90% of the total perfect foresight value through optimisation algorithms.

7.1.2 Availability of customer assets

Availability of customer assets further impacts the value which can be achieved through managed charging. This impact can be:

- **direct** – with the asset having a reduced available capacity (kW) in a period in which it would ideally be used, or
- **indirect** – where there is a chance that the asset will not be available, and therefore the optimiser assumes a conservative view of availability to ensure service provision. This is most relevant for markets which require explicit bidding of response in advance.

Under the current market design, wholesale and network cost savings are impacted typically only by direct unavailability, whereas FCAS markets require explicit bid volumes at the day-ahead stage and therefore are more likely to be impacted indirectly from conservative availability assumptions.

Therefore, we would expect to see a greater reduction of expected FCAS revenues compared with perfect foresight (relative to wholesale or network).

Storage

For relatively new assets which are located permanently in the customer home, such as BESS, a high availability (typically above 90%) can be assumed for each customer. The availability of the aggregated portfolio to provide response is dependent on both asset availability and communications.

Work is ongoing in Australia to determine the ability of aggregated portfolios to respond at scale, in particular across domestic residential storage. For example, the AEMO VPP Demonstration knowledge sharing report[56] investigates the response of the South Australian Tesla / EnergyLocals VPP. Enablement volumes of 1MW were determined via a portfolio-wide test, and understood to be less than the total installed capacity of the batteries within the VPP. There were examples of over and under delivery of response in an FCAS event. For example, there was an instance where dispatch was greater than target volume, which is assumed to be due to over-dispatch of assets to ensure the response target was met given uncertainty of asset response. In another instance, 83% of the target response was provided, reportedly due to technical issues limiting the provision of all of the targeted response.

Another example is the Ausgrid Reposit VPP trial[57], which outlines one particular peak price dispatch event on 12 March 2019. Of 207 customers with an average maximum BESS dispatch power rating of 3.7kW/customer, an average of 3KW/customer was requested during the peak price window from 3:15pm to 6:15pm. Of this, the Reposit dispatch engine accepted availability of 2.4KW/customer, with 1.8kW/customer on average delivered. This response represents 60% of that requested, and only around 50% of the average maximum response.

While these studies provide insufficient data to be conclusive, it suggests that it would be prudent to apply a reduction/discount to the maximum potential wholesale, network and FCAS revenue shown in this report due to asset availability.

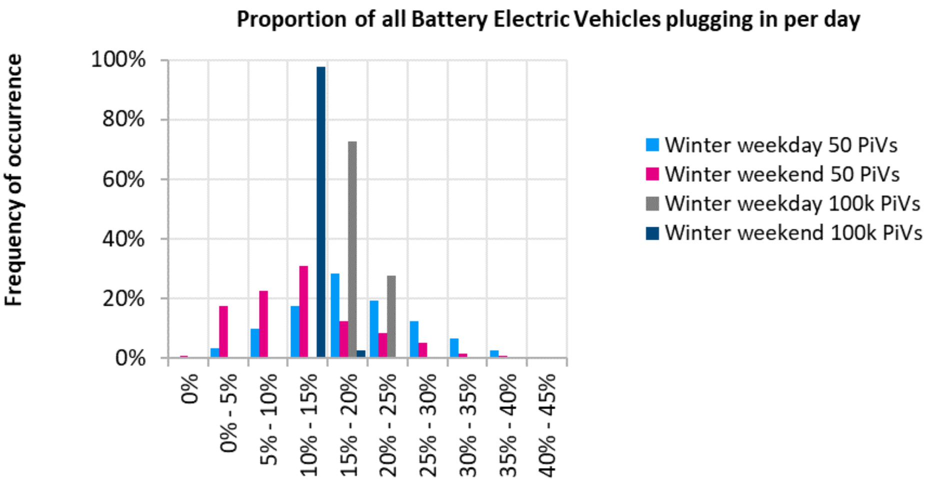
Electric Vehicles

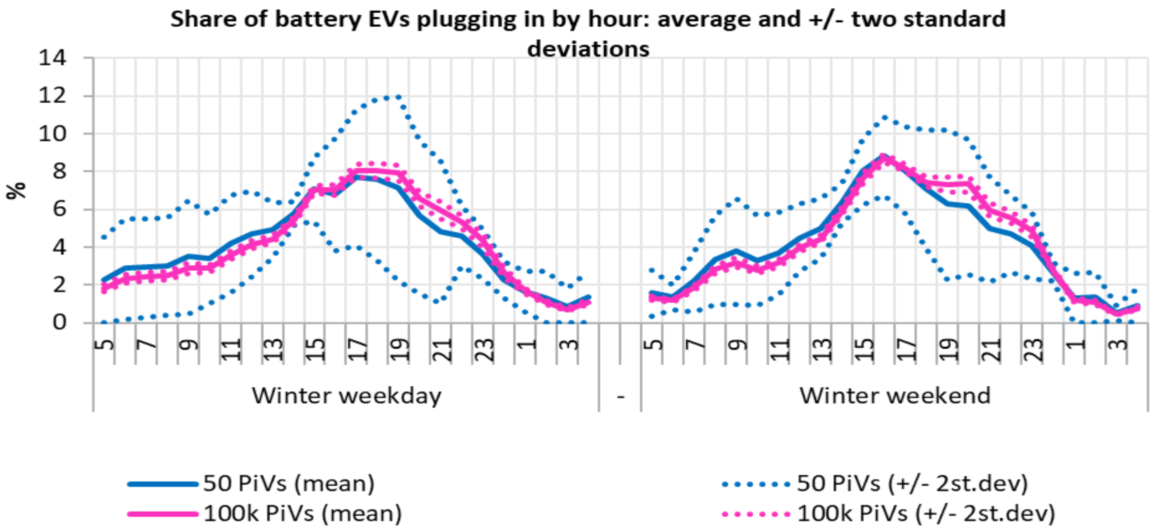
For assets not permanently at home, such as EVs, predicting availability of the battery is more difficult. The modelling contained in the study assumes a car returns at 5pm with the battery around 85% full, and is required by the customer at 7am 100% full, while maintaining a minimum charge of 20% for unexpected travel requirement. This example was selected to be consistent with the average daily energy consumption of 7kWh from AEMO's ESOO[58], and a Tesla Model 3 Standard car[59], while providing a view of maximum potential value assuming significant flexibility and ability for the battery to discharge to meet evening peak.

[56] AEMO Virtual Power Plant Demonstration, Knowledge Sharing Report #1, March 2020.
[57] Ausgrid's Battery Virtual Power Plant Phase 1 Summary, August 2019.
[58] Residential, Convenience Charging profile (VIC, Central) from AEMO's 2019 Electricity Statement of Opportunities Inputs and Assumptions workbook.
[59] https://ev-database.org/car/1060/Tesla-Model-3-Standard-Range.

However, recent mass-market studies which have been conducted in the UK by the Energy Technologies Institute[60] suggest a significant variation in customer behaviour across a trial of 50 customers (sample size extrapolated through modelling to 100,000 customers). As shown below, the aggregate behaviour of consumers implies that they tend to plug-in on average once every few days. In addition, that while post-work charging (here, 5pm) is the most common plug-in time, there is significant variability to charging time throughout the day. While customer behaviour will vary across markets with driving patterns, a similar level of variability is expected to exist for Australian customers. This variability, and particularly the average availability of the EV to be plugged in and available to discharge through the evening peak price period, will have a significant impact on total value across a portfolio.

Figure 45 - Variation of battery EV Plug in Vehicles ('PiV') plug-in times across a portfolio





Demand side response

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[60] D7.3 – Demand Management Aggregator Framework, ETI ESD Consumers, Vehicles and Energy Integration Project 2019.

Other demand response areas that were modelled in this study are HVAC and pool pumps. With regard to HVAC trials to control customer load, one Ausgrid trial 'CoolSaver' explored the ability to reduce air conditioner capacity on compliant AC units by 50% and 75% respectively. Although the test sample size for the Ausgrid trial was small, Ausgrid anticipated that on average they were able to reduce demand through sending a signal to compliant HVAC devices by 1-1.5kw (out of 10kw devices). Trial participants were likely to be engaged energy customers, but the results did show that on average only about 10% of participants in the central coast region performed an override of the HVAC controls during the five peak events. While this is another relatively small sample size, the response is consistent with the modelling in this study, which found an average of 1-1.7 kW HVAC load from a typical customer at high price times, and may suggest that limited further discounting is required for customer override.

7.1.3 Price influence at scale

We modelled a single customer against a set of market prices assuming the behaviour does not change the price. However, when many customers operate in a similar manner there may be a significant impact on price, particularly where their volume is large compared with total market volumes. Our Reference case includes 285 MW of embedded energy storage in Victoria[61] for FY29 while our FCAS price projections assumes FCAS participation volumes of 160 to 280 MW (primary and secondary response markets) from distributed generation across the NEM. This volume is representative of 56,000 typical households with a 5kW BESS. Given the significant uptake of rooftop PV in the NEM, which our reference case assumes to be 13GW by FY29, this represents a small portion of PV customers participating in this market. The wholesale prices considers an uptake of 36,000 EVs by FY29[62]. However, these are not all modelled with full V2G capability in the Reference Case.

If more customers installed batteries, or purchased EVs and participated in wholesale and FCAS markets largely, there could be a further downward impact on price.

7.2 Product design

There are a relatively small number of tariffs designed for customers with DER flexible assets today, and they tend to have low scale and maturity. However, retailers are innovating at pace and there are a range of trial products that do exist nationally and internationally, which provide a level of insight into varying tariff structures, and how the market may evolve to facilitate DER flexibility.

Two broad ways to illicit response from flexible DER assets have been categorised in Figure 46 below. Either a retailer or other third party directly controls the asset ('Prices for Devices'), or a price signal is passed through to the customer to change its behaviour ('Active customer flexibility').

It is worth noting that the spectrum between these two options allows for differing degrees to which end-customers are exposed to dynamic prices – and, inversely, the degree to which control of devices need to be provided by the customer to the supplier, or some other party, to manage the associated devices. The structure of retail tariffs vis-à-vis the structure of network tariffs would play a key role in determining where a particular retail offering sits on the spectrum, as any differences in structure

[61] Total embedded energy storage systems (aggregated and non-aggregated) from ESOO 2019.

[62] Accounts for all EVs including buses, light commercial EVs, residential EV and EV trucks.

creates volume basis risk for retailers which need to be managed by, for example, having control over customers' devices.

For example, 'Prices for Devices' would apply where the network tariff is highly dynamic while the corresponding retail tariff is fairly static. Conversely, 'Active customer flexibility' would apply where the retail tariff and network tariff are both highly dynamic, such that differences between the two tariffs – and hence the exposure of the retailer to basis risk – is minimal.

Figure 46 - DER asset tariff spectrum

Prices for Devices		Active customer flexibility
The customer gives the supplier remote control of some assets to create flexibility. The retailer gives the customer a discount which reflects the value it can create from the flexibility, via a simplified tariff		The retailer exposes the customer to price shape to incentivise a response from flexibility. The customer is responsible for generating value by optimising their demand.
The retailer takes risk on being able to realise the assumed level of flexibility, which will have been priced.	Risk	The customer takes risk on value being created from flexibility.
The retailer has full market access and granular price signals.	Price	The price signal available to the customer is defined by the retailer.
Centralised control solution required for direct control of larger discrete loads. Typically high ability to flex load.	Control	No centralised control solution required, allowing small loads to be flexed. Customer behaviour drives ability to flex load.

The effect of automation to customer response remains somewhat unclear, due to most studies having a small number of data points. A review on DSR value realisation[63] in Great Britain highlights that customer behaviour response to price signals is not straightforward. Studies have shown that residential customers do respond to dynamic time of use prices to some extent. However, enabling technology, automation and product simplification of market access products are the key components to influencing a greater level of response to market prices at scale.

'Prices for Devices' products have been a focus of innovation recently, given that:

- direct control and automation of response has typically seen to provide greater levels of response than methods which require a change of customer behaviour, and is essential for ancillary service provision, and
- maximising value for optimisation requires access to full granularity of wholesale, FCAS and network prices, which have historically been available to retailers, and more recently aggregators but is uncommon for end customers.

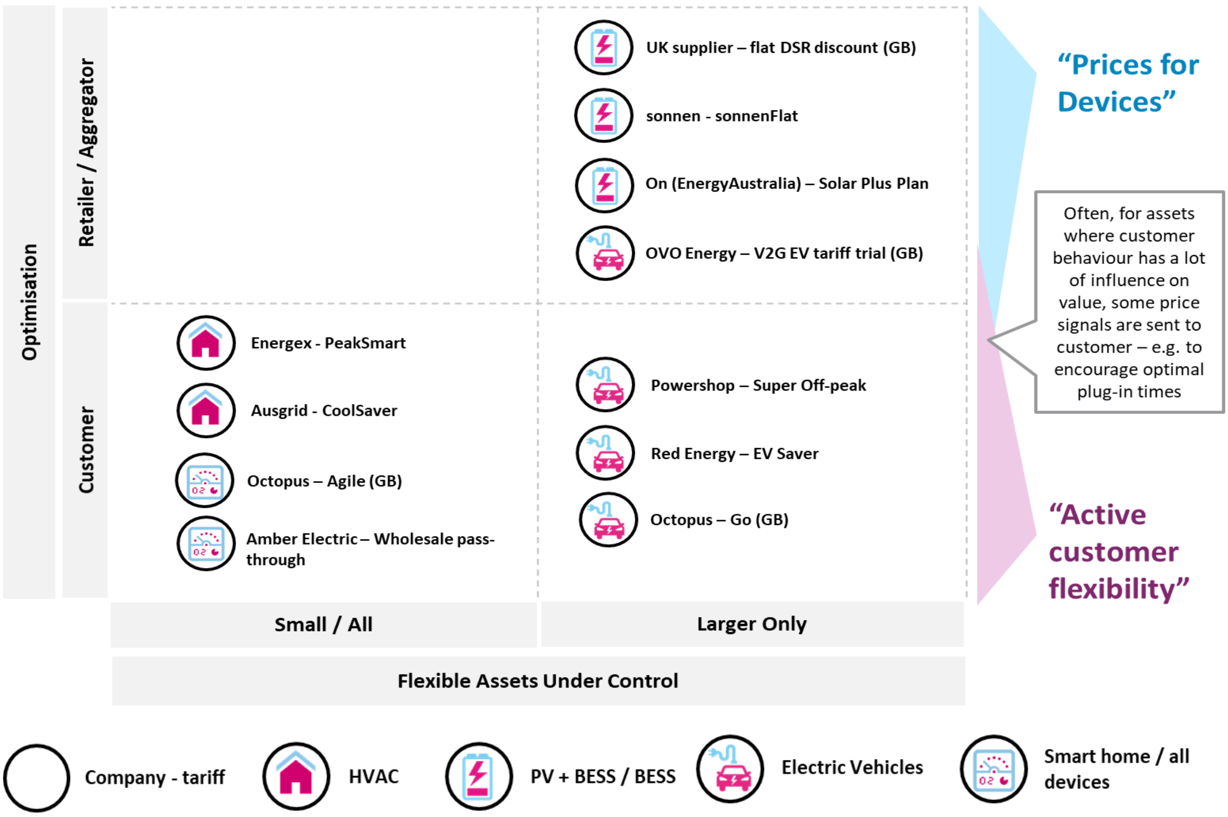
In these products, the retailer manages the market risk and flexible asset operation, passing value through to the customer via a simplified tariff structure. It will typically charge the customer for the

[63] BEIS, Realising the Potential of Demand-Side Response to 2025, 2017.

management of this risk either directly (e.g. via a flat monthly fee) or by taking a larger share of the total asset value. In comparison, in tariffs which encourage active customer flexibility, the retailer passes the majority of the market price risk and value through to the customer. The retailer carries little risk while the customer must change their usage behaviour to adapt to more agile pricing. This may offer more value to customers who are engaged and operate their asset optimally, however it also increases customer exposure to price spikes, or other potential cost increases of sub-optimal behaviour.

Figure 49 below outlines some examples of customer tariffs designed to cater for customers with DER flexibility. These examples have been chosen from within the National Electricity Market, or Great Britain, as an international market with a growing focus on Electric Vehicle tariff design. They are intended to be illustrative, contain both commercially-available products and past or present trials, and by no means are an exhaustive list of products available.

Figure 47 Example retail tariffs for DER flexible assets



The examples above illustrate a few key themes we see globally in this space:

1. **The majority of Prices for Devices tariffs have been focused on large DER assets with relatively stable operating profiles**. This is perhaps not surprising given the significantly larger value available (as outlined in the results section of this report). In addition, the proportionally lower control costs for single large, discrete assets compared with multiple smaller home devices. These have tended to focus on PV + BESS system households and offer fixed rates for electricity over the term, if the customer has a compliant solar and BESS onsite. The PV and BESS systems can be owned either by the customer (e.g.

sonnenFlat) or by the retailer (e.g. Solar plus Plan) through the entire agreement period. Value is passed through to the customer via a simplified flat ($/kWh) rate, or fixed cost ($) per month. The retailer takes on the risk that this value will not be realised, and therefore there are often conditions of customer eligibility – such as minimum consumption, or asset size which are imposed to increase likelihood that the expected value is achieved. The retailer also may take on the risk that the asset is available, which for PV + BESS systems is relatively consistent and easy to predict compared with mobile assets such as EVs.

2. **A price signal to the customer is common for electric vehicle tariffs**. For assets such as EVs, where customer behaviour has a larger impact on the total value which can be realised, there are more examples of tariffs which provide a price signal to the customer. This is because customer plug-in time is harder to predict and has a material impact on value achieved. To make the operational profiles of EVs less unpredictable, the Powershop, Red Energy and Octopus examples above all provide examples of super off-peak EV charging windows, which incentivise EV customers to charge at pre-defined windows of expected low wholesale prices. These are common for EVs which are only a load, and the customer controls the simple charging behaviour. For V2G chargers, the optimisation is a little more complex. For example, OVO Energy are currently trialling a tariff under which the customer specifies plug-in timing, and required time and state of charge for plug-out, and the retailer optimising the charge/discharge of the BESS across energy and ancillary service markets. This behaviour is similar to that modelled in this study, and the value of these actions are passed through to the customer as a discount to the retail bill[64].

3. **Prices for Devices offers for smaller assets have seen less recent development.** Due to the complexity of control and optimisation of a large number of small household assets, and the relatively low value of flexing load such as pool pumps, HVAC or whitegoods, tariffs designed for optimisation of smaller scale flexibility have been less of a recent focus for retailer tariff development. While controlled load tariffs for hot water systems have been evident for many years, recent development of flexible tariffs for smaller assets have tended to pass granular price signals directly through to the customer. For example, Octopus's Agile tariff provides the customer with a dynamic day-ahead view of hourly wholesale price, and Amber Electric exposes the customer to wholesale spot price. There is significant technological development underway with a focus on control of distributed assets, and we would expect technologies which facilitates remote control of smaller assets at a cheap enough price would unlock these products for smaller assets.

While many of these examples are trials, or low-maturity products, their presence suggests that retailers or aggregators expect to achieve value from managing flexible DER assets and are willing to manage the risk which arises from managing customer flexibility while providing the customer with a simplified tariff structure. This may offer an opportunity for customers with DER assets who do not want to actively engage in the optimisation of their assets in the market with an opportunity to realise value from flexibility.

[64] https://www.ovoenergy.com/electric-cars/vehicle-to-grid-charger

8 Conclusions

The results show that there is a significant amount of potential value for managed flexibility of DER assets without materially impacting customer experience. This value is similar for the typical customers considered across both ToU and demand tariffs, showing that the asset responds in a flexible manner to take advantage of price signals in both tariff structures. The potential value of managed flexibility increases considerably with storage assets when compared to non-storage assets, due to their ability to not only load shift but also arbitrage by exporting into the grid during periods of high prices. The large size of the storage systems typically seen in the market today, whether EV battery or BESS, is sufficient to frequently reduce customer import to zero over the peak network price window. Furthermore, participation in the ancillary services market is a material additional revenue stream available to aggregated portfolios today, which is expected to continue to add value into the medium term.

To capture this value, an emerging range of products are being trialled both domestically and globally, in which retailers or third party aggregators optimise assets and pass some of the value through to the customer under a simplified retail structure. The majority of products or trials to date have been focused on larger assets as they represent the greater value for managed flexibility. Management of smaller assets, such as load shifting of pool pump usage, represents less value but maybe implemented easily.

Under these products, customer experience and comfort remains more or less, as it was previously, with the retailer managing the asset to reduce exposure to granular grid tariffs, and create value in the energy and FCAS markets. Not all of the potential value shown is expected to be captured by assets in reality, due to imperfect availability, price forecasting, and potential reduction in market prices due to coordinated DSR action. However, the modelling contained in this study, and the observed emergence of trial offers in the market, suggest that sufficient value is available to make this an attractive proposition for a retailer.

The extent to which these prices for devices offers extent to smaller assets will depend on technological innovation to reliably and cheaply control smaller assets.