Regulatory proposal 2026–31

Tariff structure statement

Explanatory statement

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Acknowledgement of Country

Powercor acknowledges and respects the Traditional Owners as the original Custodians of the lands and waters our networks cover; lands First Peoples have occupied for tens of thousands of years.

Powercor pays our respects to Elders past and present and acknowledge their ancient and continuing connection to Country.

About this document

Every five-years, the Australian Energy Regulator (AER) reviews our forecast plans for approval. This determines the services we deliver, and the revenue we recover from our customers.

Our regulatory proposal sets out our plans for the 2026–31 regulatory period.

One component of our proposal is our proposed tariff structures which comprises two primary documents:

- Tariff Structure Statement – Compliance Document – which sets all the tariff structures we are proposing
- Tariff Structure Statement – Explanatory Statement – which explains why we are proposing these tariff structures.

This document is the Explanatory Statement.

Table of contents

1. Overview 5

2. Our role in electricity supply 7
2.1 Network tariffs 7
2.2 Other distribution services 8

3. Our future operating environment 9
3.1 Victorian Government policies 9

4. Stakeholder engagement 11
4.1 What we've heard 11

5. Role of network tariffs 15
5.1 Emissions reduction objective 15
5.2 Demand management 15
5.3 Implications for the role of network tariffs in demand management 16
5.4 How network tariffs have been considered in our demand forecasts 17
5.5 Other considerations 17

6. Tariff classes 18

7. Proposed network tariff reforms 19
7.1 Residential 19
7.2 Small business 30
7.3 Unmetered supplies 35
7.4 Medium business 35
7.5 Commercial and industrial 36
7.6 Flexible connections 38
7.7 Other tariff issues and complementary measures 50
7.8 Long run marginal cost, stand-alone and avoidable costs 52

1. Overview

Network tariffs are a key element of our network strategy and need to balance a range of stakeholder objectives. We have undertaken extensive consultation on network tariffs.

Based on stakeholder feedback, the Victorian distributors are proposing to continue to align residential and small business tariff structures, have no residential demand charges and have no mandatory export charges.

The main tariff changes which we propose are summarised in table 1.1.

TABLE 1.1 SUMMARY OF PROPOSED TARIFF CHANGES

PROPOSED CHANGE	REASON FOR CHANGE
Add a low-priced saver period from 11am–4pm into the residential time-of-use tariff	Soak up the increasing solar exports on residential networks which will help increase solar hosting capacity and allow customers without solar to still benefit from it
Shorten the peak period from 3–9pm to 4–9pm in the residential time-of-use tariff	Adapt to the growing rooftop solar generation which is pushing the residential peak period later in the day
Introduce a new two-way opt in residential CER tariff	Provide better price signals to retailers of homes with flexible loads such as home batteries and vehicle-to-home or vehicle-to-grid
Maintain the option for customers consuming less than 160 MWh per year to opt out of a demand tariff	Provide an opportunity for customers with low utilisation, such as EV charging stations, to establish their businesses
Introduce a trial tariff for dedicated low voltage EV charging sites, such as pole-mounted EV chargers	Provide an opportunity for dedicated low voltage EV charging sites to be more affordable by responding to price signals
Introduce a new winter incentive demand period for C&I tariffs	Adapt C&I tariffs in those parts of the network which are or will become winter peaking largely due to electrification of space heating
Introduce new non-residential flexible connection tariffs	Complement new flexible connection arrangements, for instance with community batteries, grid storage and renewable generation

We also propose the following measures to complement our tariffs:

- campaigns to encourage residential customers to optimise their energy bills by switching to a retail time-of-use tariff and matching their energy usage to low price periods
- literacy programs focussed on customers who may be at risk of energy poverty
- energy advisory services targeted at assisting communities, welfare agencies and other institutions on bespoke data requests
- more support for our commercial and industrial customers and storage and generation proponents, including improved online resources on how their network charges are calculated.

2. Our role in electricity supply

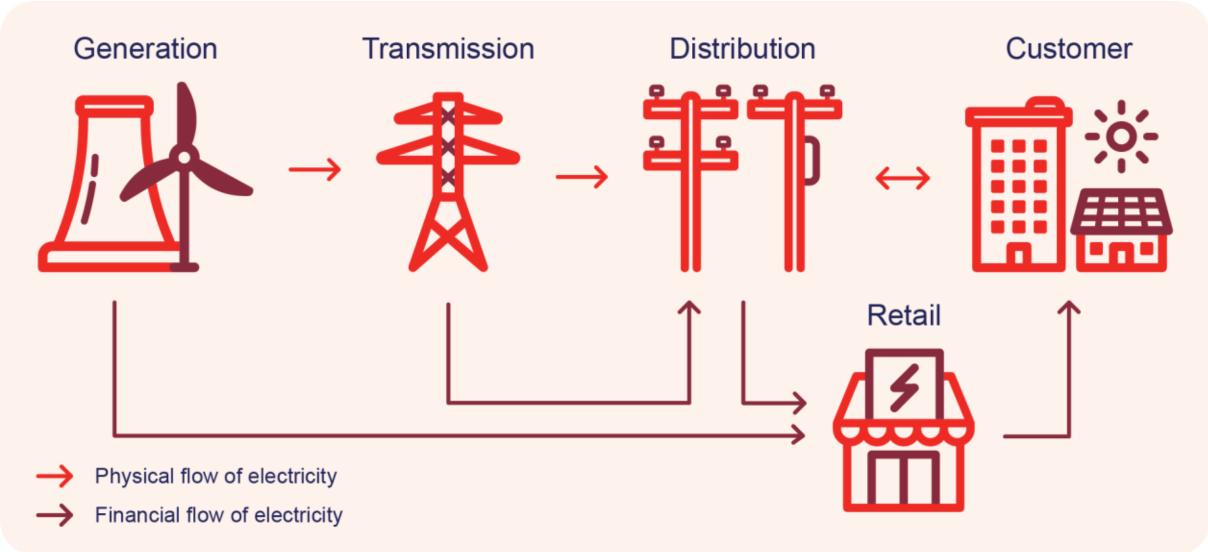
Our distribution network is at the centre of the electricity supply chain connecting over 900,000 homes and businesses to a safe and reliable supply across Melbourne’s outer western suburbs, and central and western Victoria.

While electricity was traditionally transported by networks from generators to customers, customers can now export electricity into the network to other customers.

We also pass network charges on to electricity retailers, who in turn pass them on to customers via electricity bills.

These physical and financial transfers are shown in figure 2.1.

FIGURE 2.1 THE ELECTRICITY SUPPLY CHAIN



2.1 Network tariffs

Network tariffs cover the cost of transporting electricity to and from our customers' homes or businesses. Network tariffs recover distribution, transmission and Victorian scheme costs.

Based on the Victorian default offer, network charges comprise approximately 31 per cent of our typical residential customers electricity bill, and approximately 39 per cent for our small business customers.

Our network tariffs are grouped into the tariff classes shown in table 2.1 which shows how are customer numbers and network revenue are distributed across our tariff classes. We are not proposing any changes to our tariff classes.

TABLE 2.1 OUR TARIFF CLASSES

TARIFF CLASS	NUMBER OF CUSTOMERS	PROPORTION OF NETWORK REVENUE
Residential	823,905	44%
Small and medium business	109,074	22%
Large low voltage	3,189	23%
High voltage	200	8%
Sub-transmission	18	3%

2.2 Other distribution services

We also provide other distribution services to customers in our distribution area which include:

- metering services to over 900,000 customers consuming less than 160 MWh per year
- public lighting services to councils and the Department of Transport
- ancillary network services.

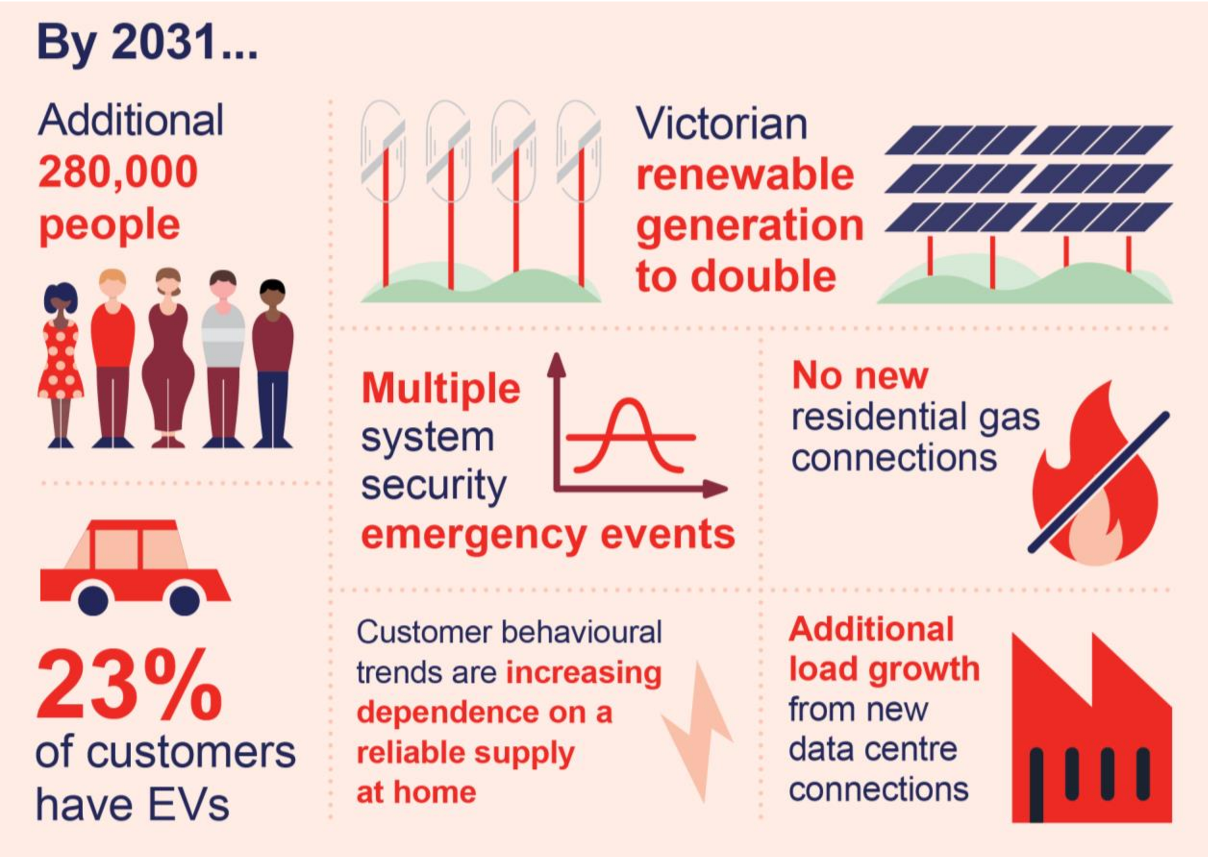
This document only covers network tariffs.

3. Our future operating environment

The way our customers are using electricity is rapidly changing. The electrification of transport, gas substitution, continued growth in rooftop solar, uptake of storage, and population growth will all impact the way the distribution network is used.

For example, the expected changes in our operating environment by 2031 are shown in figure 3.1.

FIGURE 3.1 EXPECTED CHANGES IN OUR OPERATING ENVIRONMENT BY 2031



3.1 Victorian Government policies

Government policies are a key influence in the adoption of new technologies, and the Victorian Government has the following relevant targets:

- greenhouse gas emissions to be 45–50 per cent below 2005 levels by 2030 and net zero by 2045
- 2.6 gigawatts of storage capacity by 2030 and 6.3 gigawatts by 2035
- 65 per cent of electricity generated in Victoria to come from renewable sources
- 50 per cent of all new light vehicle sales to be zero emissions vehicles by 2030.

The Victorian Government's gas substitution roadmap also outlines a pathway to transition away from residential gas in Victoria, including its ban on new residential gas connections from January 2024.

The Victorian Government is now consulting on regulations for new and existing buildings to achieve further gas substitution.

The Victorian Government's solar homes, businesses and apartments programs will enable installation of solar, hot water or battery systems on over 770,000 homes and businesses across the state.

Of particular relevance to network tariffs, the Victorian Government has also effectively mandated the following for Victorian distribution network tariffs:

- customers cannot be mandatorily assigned to an export charge
- residential and small business customers cannot be mandatorily assigned from a single rate tariff unless they install or upgrade their solar, upgrade to three phase or install an EV fast charger in their home or business.

4. Stakeholder engagement

Since late-2021, we have been engaging with our customers and key stakeholders as part of a comprehensive engagement program to shape our regulatory proposal. Network tariffs were one of many topics integrated into our Broad and Wide, Deep and Narrow and Test and Validate engagement activities, as described in our regulatory proposal.

Network tariffs were specifically included in the following engagement activities:

- three joint Victorian electricity distributor forums focussed on small customer tariffs, attended by customer advocates, renewable energy advocates, vulnerable customer advocates, retailers, government, and regulators
- a joint Victorian electricity distributor small business consultation paper
- a joint CitiPower, Powercor and United Energy storage consultation paper
- two joint Victorian electricity distributor customer vulnerability roundtables
- a customer energy resources (CER) integration forum
- Monash University Future Home Energy Demand report
- two commercial and industrial (C&I) forums
- a discussion with the Energy User's Association of Australia and some of their members
- multiple interviews with C&I customers
- a retailer tariff forum
- a tariff directions paper which was included with our draft proposal
- ad hoc meetings with retailers, commercial and industrial customers, grid-scale storage proponents, community battery proponents, the Victorian Government, the AER and other distributors.

Network tariffs were discussed extensively with the Customer Advisory Panel (CAP). The CAP comprises 11 diverse and unbiased members, including an independent Chair and Deputy Chair.

Whilst all stakeholder feedback was considered, not all stakeholder views could be incorporated into our final proposed network tariff structures.

4.1 What we've heard

The key themes emerging from our stakeholder engagement indicate that network tariff design involves a trade-off between potentially competing objectives—maintaining simplicity and stability, versus adapting tariffs for the energy transition. Another theme was a desire for more information and education.

These key themes were expressed by both residential and business customers. A summary of these engagement findings is outlined in table 4.1.

TABLE 4.1 KEY ENGAGEMENT FINDINGS

Keeping tariffs simple and stable:

- many customers, both residential and business, express a strong preference for simple, stable, and predictable pricing structures
- around half of residential and small business customer are unfamiliar with the concept of a time-of-use tariff
- many C&I customers did not know how their demand charges are calculated
- full-time workers and businesses have limited flexibility to adjust energy consumption behaviours
- there is concern about customers experiencing vulnerability being exposed to bill increases because of changes to network tariff structures.

Adapting for the energy transition:

- stakeholders highlight the importance of tariffs being sufficiently flexible to accommodate evolving customer behaviour patterns driven by prosumers, electric vehicles (EVs), batteries, electrical appliances and lifestyle changes
- residential customers indicated that they have flexibility in rescheduling EV charging to low price periods
- some stakeholders sought more cost-reflective network tariffs to address what they considered to be growing inequities arising from existing tariff arrangements which are not reflective of how network costs will be incurred under the energy transition
- some stakeholders believe that network tariffs should be designed to improve the financial viability of public EV charging, grid-connected storage, and rooftop solar recognising their broader environmental benefits, rather than reflect costs imposed on the network
- those business customers with flexibility, including storage customers, want to be rewarded for behaviour which assists the network
- there was a push for reforms that would allow businesses and communities to directly benefit from local energy resources
- negative sentiment was generally expressed towards export tariffs

Information and education:

- residential customers, especially those experiencing vulnerability, express a desire for more information on energy usage and tariff structures to assist them better manage energy bills
- business customers wanted simpler easily comprehensible educational materials that explain their network tariff structures in customer-friendly terms.

Table 4.2 shows the relevant tariff feedback we received in our CAP report on our tariff directions paper, and our response.

TABLE 4.2 OUR RESPONSE TO KEY FEEDBACK RECEIVED FROM OUR CAP

CAP FEEDBACK	OUR RESPONSE
Undertake more comprehensive engagement with C&I customers that captures the significant differences between different types of C&I customers; to ensure their views as adequately considered in its proposal	We will explore new ways for more meaningful engagement on network tariffs with C&I customers before our revised proposal
Provide more detail in the final proposal about how it plans to manage the uncertainty in forecasts of energy usage changes due to the energy transition, and the changes in costs and thus prices that could result.	Under our pricing framework, network tariff rates are adjusted each year in response to actual energy usage and updated forecasts of energy usage for the forthcoming year to ensure that we don't recover any more revenue than the revenue cap set by the AER.
We (in partnership with the other Victorian distribution businesses) should continue to work with the Victorian Government to develop an approach to transition all residential customers to the proposed time-of-use (ToU) tariffs over the 2026–31 period in a way that manages perceived and actual adverse impacts on vulnerable customers.	We don't believe that all residential customers can be transitioned to TOU tariffs over the 2026-31 regulatory period without adverse short-term bill impacts for some residential customers or without business customers cross-subsiding residential customers.
We should identify ways to facilitate increased customer understanding of how ToU tariffs could benefit them in order to increase voluntary adoption and build a stronger evidence base of the impact of ToU tariffs on different types of customers	We plan to design and run a campaign to encourage residential customers to optimise their energy bills by switching to a retail TOU tariff and matching their energy usage to low price periods. We are planning to develop a series of residential appliance / CER consumption profiles to better understand how a residential customer's appliance / CER mix affects their consumption profile, their ability to respond to prices, and the tariff structure which is best suited to them.

Table 4.3 shows specific feedback received on our tariff directions paper, and our response.

TABLE 4.3 OUR RESPONSE TO KEY FEEDBACK RECEIVED ON OUR TARIFF DIRECTIONS PAPER

STAKEHOLDER FEEDBACK	OUR RESPONSE
Mixed feedback was received from C&I customers on the proposed winter peak demand charge. Some supported the concept of cost-reflective tariffs, others criticised its fairness, particularly for sectors with inflexible energy needs	We think there is misunderstanding about the winter peak demand period. It is not a new charge, but a new period when the charge could be applied. It would be inefficient to apply a summer peak charge in a winter peaking area and therefore we think that this change is important.
A call was made for more interactive tools to help C&I customers assess and optimise their energy costs	We will provide additional resources for C&I customers. The details still need to be scoped.
ACEnergy expressed strong support for the newly proposed tariffs, labelling the proposal as a 'significant step toward balancing costs and encouraging the adoption of new technologies' which aid in emission reduction. They went on to say that 'the new tariffs are the most balanced seen across the National Electricity Market (NEM) and are set to benefit both solar and non-solar customers while enhancing the performance of energy storage systems'.	This is strong endorsement of our proposed residential low-priced solar saver period, and of our flexible connection tariffs.
Although the networks do not set export tariffs, council members were particularly focused on how the structuring of tariffs would impact solar investments. They expressed concerns that tariffs are increasing the cost of exporting solar and have posed significant challenges to councils investing in promoting solar uptake, especially for vulnerable community members.	There is a balance to be struck between designing tariffs to encourage solar investments and designing more cost-reflective tariffs to reduce cost pressures on non-solar customers who are more likely to be vulnerable. We believe that our proposed tariffs strike the right balance.
Support for time-of-use tariffs to encourage energy consumption during off-peak periods and to reduce the excess solar being exported during the middle of the day	This is strong endorsement of our proposed residential low-priced solar saver period and our proposal to assign customers with fast EV chargers to time-of-use tariffs.

5. Role of network tariffs

Network tariffs are a key tool in managing our network efficiently, but also fairly for all customers. In the context of the energy transition and our changing operating environment, network tariffs can support meeting emissions reduction objectives and demand management.

5.1 Emissions reduction objective

In 2023, an emissions reduction objective was included in the national energy objectives. The transition to electrification of transport, gas substitution, storage and renewable energy will be important in achieving emissions reduction.

To meet the emissions reduction objective, we need to facilitate the integration of these technologies into the network. Consequently, connection policies, service offerings, tariff structures and network planning will need to be more integrated and adapt to the transition.

Consistent with the above, a key theme to emerge from our stakeholder engagement is that our network tariffs need to adapt to changes in energy use patterns from new technologies. In general, stakeholders still see cost-reflectivity balanced by simplicity and stability as the guiding principle for adapting tariffs to the energy transition and emissions reduction.

5.2 Demand management

The integration of customer energy resources (CER) into the distribution network involves demand and voltage management. CER resources can exacerbate peak and minimum demand, but at the same time can be harnessed to manage demand.

Network tariffs are a low-cost solution for managing demand and therefore a critical consideration. While low cost, network tariff changes impact customers, therefore our network tariff proposals are strongly driven by stakeholder engagement with key themes summarised in the previous section.

We also need to consider how network tariffs fit in with other low-cost solutions to manage demand. Examples of non-tariff demand management solutions that we are already implementing are:

- low-cost network optimisation
- controlled load hot water which allows us to control hot water heating remotely
- dynamic voltage management system
- flexible connections for high voltage generators and storage.[1]

We are also proposing the following new demand management initiatives:

- flexible export services for small customers
- building capability for flexible load connections
- flexible connections for low voltage connected generation and storage
- a platform to procure network support.

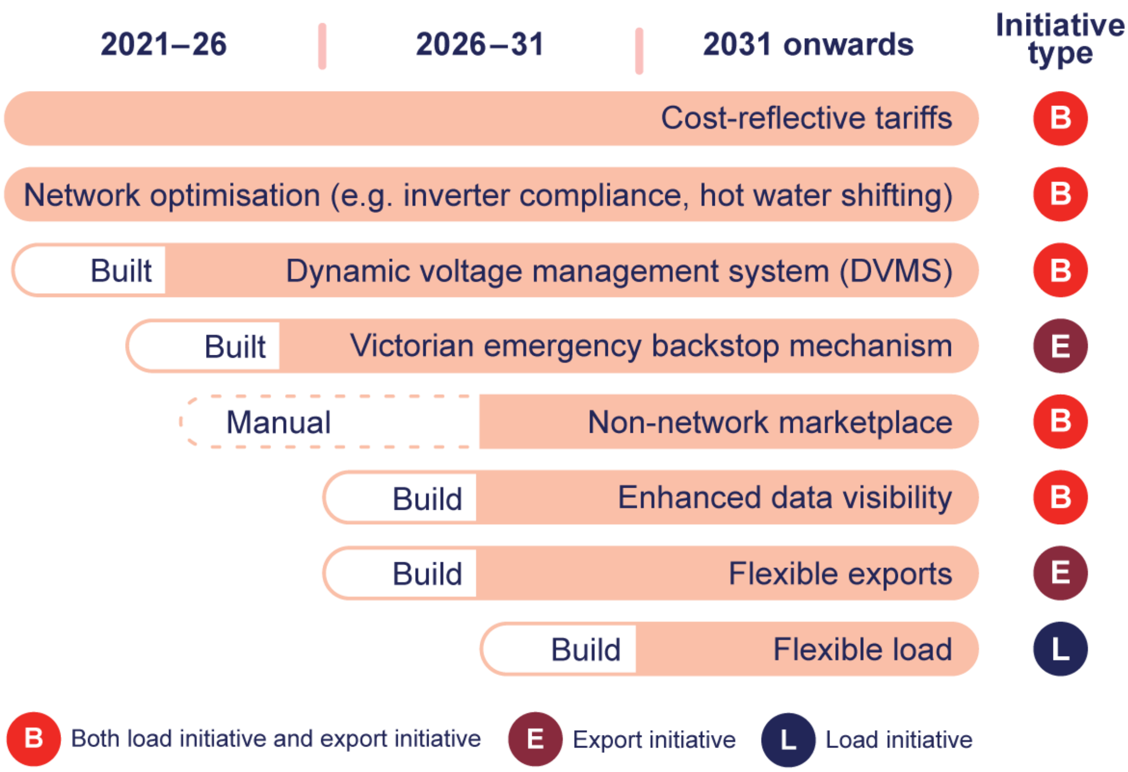
[1] HV storage and generation connect to our distribution energy resource management system (DERMS). Our DERMS allows us to secure a dynamic operating envelop by discontinuing, interrupting or limiting the quantity of electricity imported from or exported to the distribution system.

Non-tariff demand management solutions have advantages over cost-reflective network tariffs in managing shorter term locational network issues because they:

- can achieve firm demand management outcomes, whereas tariffs only provide incentives or disincentives
- can be targeted in locations where there is identifiable avoided or deferred network augmentation cost
- can be tailored to meet specific circumstances including financial arrangements, timing and duration of network support.

Figure 5.1 demonstrates how network tariffs fit into the broader suite of demand management solutions to reduce the need for augmentation expenditure.

FIGURE 5.1 DEMAND MANAGEMENT SOLUTIONS



5.3 Implications for the role of network tariffs in demand management

Regarding our proposed flexibility arrangements, the role of network tariffs in managing demand is to:

- support non-tariff demand management initiatives by providing discounted network tariff rates in return for handing us some form of control, for instance load control of hot water, limiting exports or imports, or other types of flexible connection arrangements
- signal average long-run costs across the network by encouraging reduced usage during expected typical times of future maximum demand and encouraging usage during expected typical times of low demand.

The advantage of this approach is that it allows tariffs to be simple and stable and avoids potential distributional effects of more cost-reflective network tariffs—important objectives for our stakeholders.

5.4 How network tariffs have been considered in our demand forecasts

Network tariffs have been considered in our demand forecasts as follows:

- augmentation associated with exports has been reduced to close to nothing due to our low-cost solutions which include introducing a low-priced saver period from 11am–4pm into the residential time-of-use tariff
- we have used AEMO's EV charging profile which assumes a gradual shift to prosumer tariffs
- electric hot water heating is assumed to make no contribution to maximum demand
- we have used two battery profiles – one which charges only from excess solar and discharges to support customer consumption and the other which follows market prices. Overall, batteries reduce our peak demand forecasts.

We have not assumed any reduction in peak demand due to our time-of-use tariffs. Firstly, the growth of customers assigned to time-of-use tariffs will be incremental – our initial proposal to assign all residential and small business customers to time-of-use tariffs was not accepted by our stakeholders. Secondly, quantitative analysis on our network indicates almost no change in behaviour when a customer in assigned to a time-of-use tariff. While we hope that further education and information can change this, it would be irresponsible to rely on a firm response for network planning until it is observed in practice.

5.5 Other considerations

In addition to supporting demand management and emissions reduction, network tariffs also need to take into consideration other customer and stakeholder objectives such as fairness and simplicity. These are considered further in this document for each tariff class.

6. Tariff classes

Tariff classes group retail customers together on an economically efficient basis with the aim to avoid unnecessary transaction costs to maintain compliance with:

- distribution tariff side constraints which is a customer protection to ensure no group of customers experiences price shock
- distribution revenues being between stand-alone and avoidable costs.

We propose to retain the same tariff classes as the current regulatory control period, which are shown in Table 6.1.

TABLE 6.1 PROPOSED TARIFF CLASSES

TARIFF CLASS	CONNECTION CRITERIA
Residential	• Connected to the low voltage network
Small and medium business	• Connected to the low voltage network • Consuming less than 160 MWh pa • Customers on our flexible small tariff
Large low voltage	• Connected to the low voltage network • Consuming more than 160 MWh pa • Customers on our flexible large tariff
High voltage	• Connected to the high voltage network
Sub-transmission	• Connected to the sub-transmission network • Customers on our flexible TUOS pass-through tariff

Flexible connections, which are discussed in section **Error! Reference source not found.**, have been assigned to the appropriate tariff class.

7. Proposed network tariff reforms

This section sets out our proposed network tariff reforms for the 2026–31 regulatory period in the following areas:

- residential tariffs
- small business tariffs
- medium business tariffs
- commercial and industrial tariffs
- flexible tariffs
- other tariff issues and complementary measures.

These reforms balance a range of stakeholder objectives and reflect our extensive consultation on network tariffs to date.

7.1 Residential

The Victorian distributors jointly consulted on pricing objectives and figure 7.1 summarises the outcome of that consultation. These pricing objectives underpin our proposed residential tariff structures and tariff assignment rules.

FIGURE 7.1 PRICING OBJECTIVES

Simple

Network tariffs should be simple and consistent, and readily understood by retailers, customers, and stakeholders.

Customers should be able to easily understand tariff structures and supporting explanatory materials. Explanatory materials should be readily available.

Efficient

Network tariffs should incentivise customer behaviours that make network costs more affordable and equitable in the long term.

Tariff structures provide incentive for customers to move usage from peaky evenings to the middle of the day when there is an excess of solar exports.

Adaptable

Network tariffs should be capable of being evolved for future network configurations and emerging technologies, consistent with a net zero future.

Tariffs needs to be cognisant of the continued uptake of solar, the uptake of home batteries, the uptake of electric vehicles, and electrification of hot water heating and space heating.

7.1.1 Tariff structure

In the current regulatory period, the Victorian distributors aligned their residential tariff structures. These structures are shown in table 7.1.

TABLE 7.1 CURRENT RESIDENTIAL TARIFF STRUCTURES

CHARGE TYPE	SINGLE[1]	TIME OF USE[2]	DEMAND[3]
Fixed	✓	✓	✓
Anytime energy	✓		✓
Peak energy		✓	
Off-peak energy		✓	
Maximum demand			✓

(1) Under a single-rate structure, usage charges, measured in kilowatt-hours (kWh), do not vary with the time of day.
(2) The Time of Use (ToU) structure has a high usage charge during the peak period from 3pm to 9pm local time and a low usage charge at all other times
(3) The demand tariff structure has a usage charge that does not vary with the time of day, and a demand charge that reflects the maximum monthly 30-minute demand from 3pm to 9pm local time

We also offer a secondary load control tariff with a discounted anytime usage rate for resistive electric water heaters connected to a dedicate circuit.

Table 7.2 shows that most residential customers are still on a single rate tariff.

TABLE 7.2 NUMBER OF CUSTOMERS ON EACH PRIMARY RESIDENTIAL TARIFF

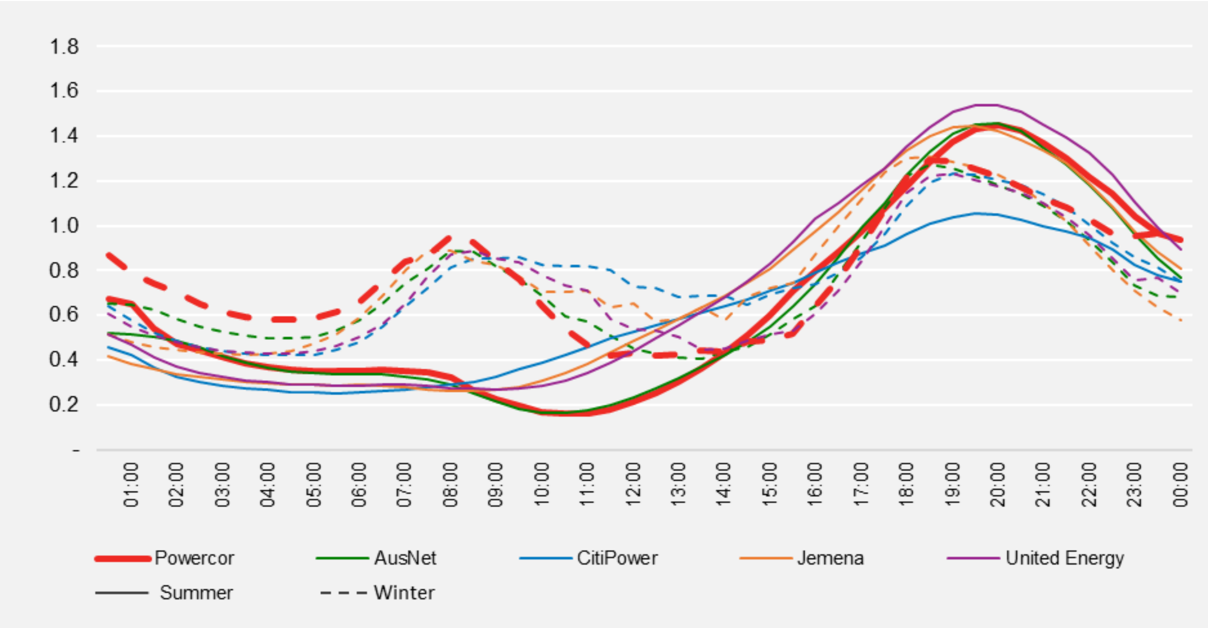
TARIFF TYPE	CUSTOMERS	PROPORTION
Single	547,272	66%
Time of use	276,135	34%
Demand	499	<0.1%

Time-of-use tariff

A key consideration in our time-of-use (ToU) tariff structure is the relevant time periods for different usage charges.

As shown in figure 7.2, the average residential daily profile on a peak summer day and a peak winter day for each of the five Victorian networks varies, with Powercor shown in bold. While the summer peak is higher than the winter peak on average, the southern areas of our network with no access to gas, experience higher residential winter peaks.

FIGURE 7.2 RESIDENTIAL LOAD PROFILES ON PEAK DEMAND DAYS

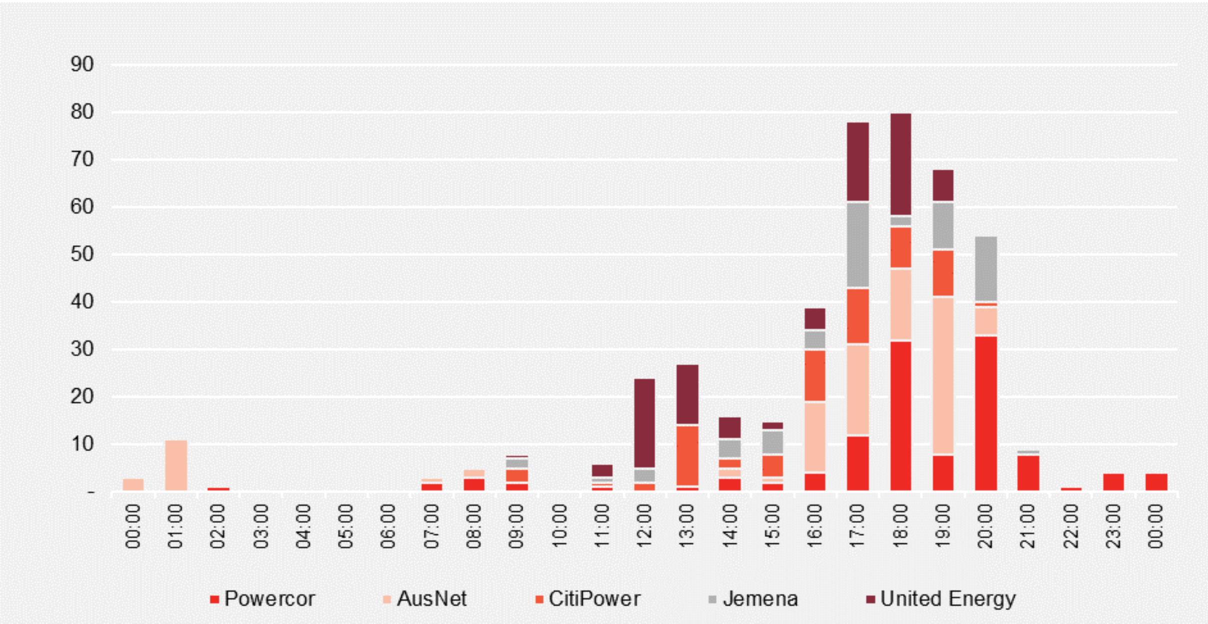


Note: Peak day imports minus exports; local time. Summer 27 December 2022; winter 18 July 2022

Peak demand is expected to grow with electrification, with the winter peak growing at a faster rate than the summer peak due to the electrification of space heating. An increasing number of residential areas are expected to move to winter peaking. As a minimum, the ToU peak period needs to capture both summer and winter.

Not only do we have to consider the residential load profile which is relevant to network infrastructure near to residential areas, but we also need to be cognisant of upstream network infrastructure. Zone substations supply a mix of residential, small and medium businesses, large low voltage and high voltage businesses and provide load profile at a point in the upstream network. Figure 7.3 shows that zone substations predominantly experience peak demand from 4pm–8pm.

FIGURE 7.3 VICTORIAN ZONE SUBSTATION PEAKS BY HOUR OF DAY (2021-23)

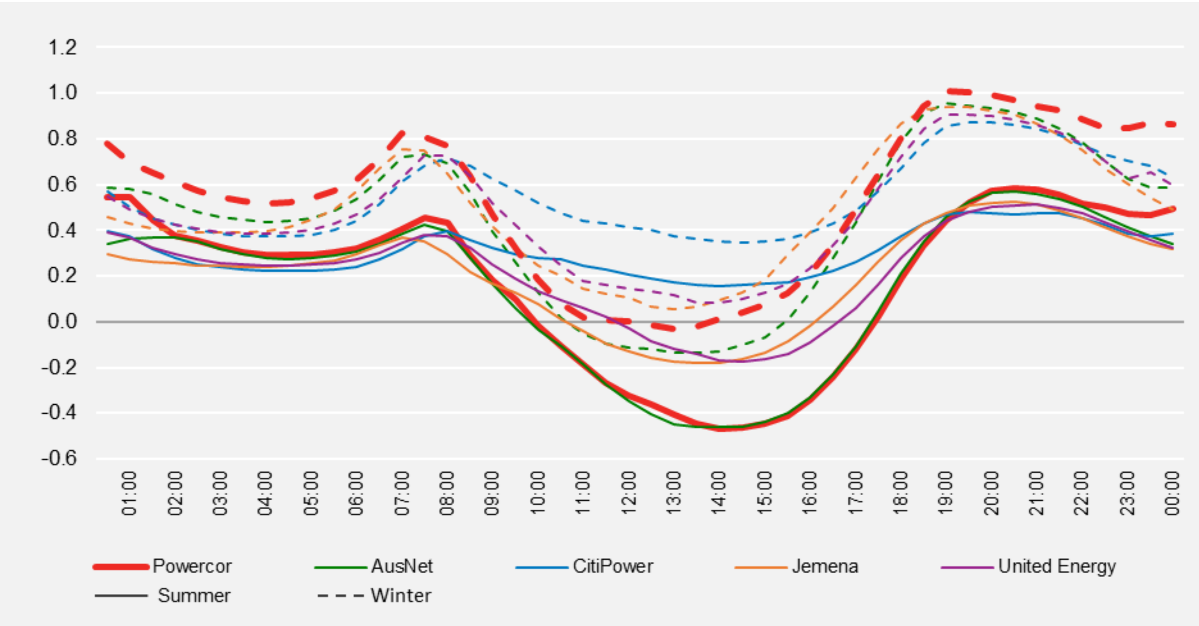


Stakeholders strongly support simplicity and are not supportive of seasonal tariff pricing. Therefore, we propose to maintain the peak period throughout the year.

We originally proposed to shift the peak period from 3pm–9pm to 4pm–10pm, to better align with peak residential usage (which has moved later with increased rooftop solar generation). Many stakeholders strongly opposed this time shift because it would make it more difficult for households to manage costs. We therefore propose a peak period from 4pm–9pm which has so far received strong support.

Figure 7.4 shows the average residential daily profile on a minimum demand summer day and a minimum demand winter day for each of the Victorian networks, with Powercor again shown in bold. The main issue with minimum demand for distribution networks is that it can result in over-voltages occurring on our low voltage networks.

FIGURE 7.4 RESIDENTIAL LOAD PROFILES ON MINIMUM DEMAND DAYS



Note: Minimum demand day imports minus exports; local time. Summer 14 February 2022; winter 31 August 2022

The Victorian Government is strongly opposed to mandatory export charges and therefore we have not considered export pricing for the default ToU tariff. Instead, we have proposed to introduce a new low-priced saver period from 11am–4pm throughout the year in the network ToU tariff. This will encourage households to shift consumption from the peak to saver period. It will also provide households without rooftop solar the opportunity to benefit from solar exports.

The saver concept received strong support from stakeholders. Additionally, we have a 'Daytime Saver' trial tariff which is being used by some retailers with noticeable behaviour change of the 2,000+ customers who have been assigned to this trial tariff.

Figure 7.5 summarises our proposed ToU tariff structure which is simple with no seasonality.

FIGURE 7.5 PROPOSED TOU TARIFF STRUCTURE

Fixed charge			
Off-peak	Saver	Peak	
12am	11am	4pm	9pm

Note: All times are in local time

CER tariff

The recent Access and Pricing rule change removed the prohibition of export charges, which will enable networks to charge or reward their customers for exporting to the grid.

There was strong support from stakeholders for an opt-in two-way customer energy resource (CER) tariff focussed on flexible import/export devices such as home batteries and EVs with vehicle-to-home or vehicle-to-grid capability.

There was general support that this tariff would include an export charge in the saver period and an export rebate in the peak period, although the Electric Vehicle Council strongly opposed the export charge.

Various views were expressed about the type of customer the tariff should be structured to appeal to. This ranged from individual customers with various types of CER to retailers or aggregators operating virtual power plants (VPPs). We are of the view that the tariff should be targeted at retailers or aggregators who would be in a better position to optimise usage and avoid a customer incurring higher charges on the CER tariff.

We received strong feedback that the CER tariff should not embed cross-subsidies. As such, we have considered the following two options:

1. strong price signals focussed on actual constraints which means only available in a limited number of areas
2. weaker price signals focussed on long-term trends and the tariff is available everywhere.

The first option is likely to be perceived to be inequitable because only a minority of customers would be able to access the CER tariff, and when a constraint is removed because of augmentation, the CER tariff would be withdrawn.

For the following reasons, our preference is option two because:

- it is consistent with the NER requirement to base tariffs on long run marginal cost
- it is likely to be perceived as more equitable
- it is consistent with our preference for securing network support through bilateral contracts outside of network tariffs.

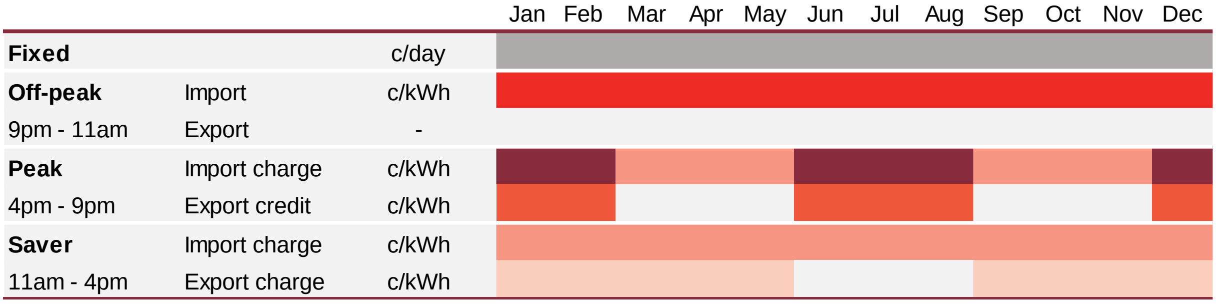
Regarding long term trends on residential networks, we have also considered the following:

- peak underlying import demand is likely to continue to occur in the 4pm–9pm period local time in summer and winter, with December to February and June to August being the most critical months. Therefore, peak import charges and export rewards should occur in this period
- peak underlying exports are likely to continue to occur in the 11am–4pm period local time in the eight-month period from September to May. Therefore, export charges should occur in this period, however these charges should be small because:
    - modelling indicates that over-voltage events due to high exports in the midday period may be less of a problem compared to peak demand events due to the introduction of flexible export products, increased midday consumption from EV charging and hot water heating, and potential response to our new ToU tariff
    - the customer export curtailment value (CECV) used to evaluate export driven augmentation is materially lower than the value of customer reliability (VCR) used to evaluate import driven augmentation, resulting in our export LRMC being materially lower than the import LRMC
    - price signals would be focussed on increasing solar hosting capacity rather than reducing investment in export driven augmentation

- in the absence of export charges on our ToU tariff, non-solar customers would be paying a rebate to CER customers to increase solar hosting capacity for solar customers therefore embedding a cross-subsidy
- the export LRMC has been calculated to be 1 c/kWh.

Figure 7.6 shows the structure of our proposed residential CER tariff. The same tariff structure applies on weekends and weekdays, and because the tariff is intended to be targeted at retailers and aggregators, the complexity of seasonality has been included.

FIGURE 7.6 PROPOSED RESIDENTIAL CER TARIFF STRUCTURE



Note: All times are in local time

The National Electricity Rules (NER) requires us to apply a basic export level (BEL) for export charges, below which electricity exports are free. We consider an economically efficient level for the CER tariff would be zero since this is an opt in tariff that does not require the consumer protections which a mandatorily assigned tariff is deemed to require. Since setting the BEL to zero is not allowed under the NER, the Victorian distributors have jointly adopted the lowest level practical of 1 kWh per day.

Demand tariff

We propose to remove the residential demand tariff because after seven years of being available, less than 1 per cent of retailers have opted customers into the residential network demand tariff.

We have consistently heard that customers do not understand the concept of demand, and there is a risk that customers inadvertently select a demand tariff.

We will move customers on the demand tariff to the ToU tariff.

Controlled load tariff

We propose to retain the secondary controlled tariff, which is a discounted rate for resistive hot water heaters separately wired to the meter on a dedicated circuit. We control the load, providing up to eight hours of power per day in return for a discounted tariff for hot water heating. A small number of legacy slab heating loads are also on this tariff, but the tariff is closed to new slab heating.

We propose not to permit EV chargers to use the controlled load tariff because participating EV owners may not receive the service they expect. For instance, they will not know when the controlled load is switched on and may plug their vehicle into a charger when it is switched off.

Interruptible tariff

With the ban on gas connections for new homes, we anticipate that hot water heat pumps will become the preferred technology. However, many models of hot water heat pumps may require more than eight hours of heating per day. For this reason, our controlled load tariff excludes heat pumps.

We have considered the introduction of a new secondary interruptible tariff for hot water heat pumps which would be separately wired to the meter on a dedicated circuit. However, due to the small capacity of heat pumps, the incentives that will be provided by our low saver period tariff, and technical issues with controlling heat pumps, we have decided not to propose an interruptible tariff.

7.1.2 Tariff assignment

Our research and engagement indicate that many households are unaware of their tariff whether they are on a ToU or single rate tariff, or what time the electricity price changes. It is, therefore, not surprising that there is little evidence that customers have responded to ToU pricing.

At the same time, household peak demand and exports are expected to grow with electrification and the continued uptake of solar, driving a need for future network investment.

The five Victorian distributors initially proposed to mandatorily assign all households to a new ToU tariff complemented by a state-wide campaign to educate customers about how they can save on electricity costs. Indicative bill impacts for various personas were presented by the Victorian distributors at a tariff forum (assuming retailers would pass through the network tariff to customers). The main finding was that, generally, customers without solar would experience a bill reduction and customers with solar would experience a bill increase. It was acknowledged that customers experiencing vulnerability could be in any of the presented personas.

There was a mixed response from stakeholders about the proposal to mandatorily assign residential customers to the new ToU tariff:

- some stakeholders saw it as a positive to step to reduce unfair cross-subsidies
- some stakeholders saw it as a positive step to provide more cost-reflective price signals which could assist to reduce future network investment
- some stakeholders were concerned with the proposed mandatory assignment, particularly considering impacts to customers experiencing vulnerability
- some stakeholders were concerned the proposal could reduce solar uptake in the future.

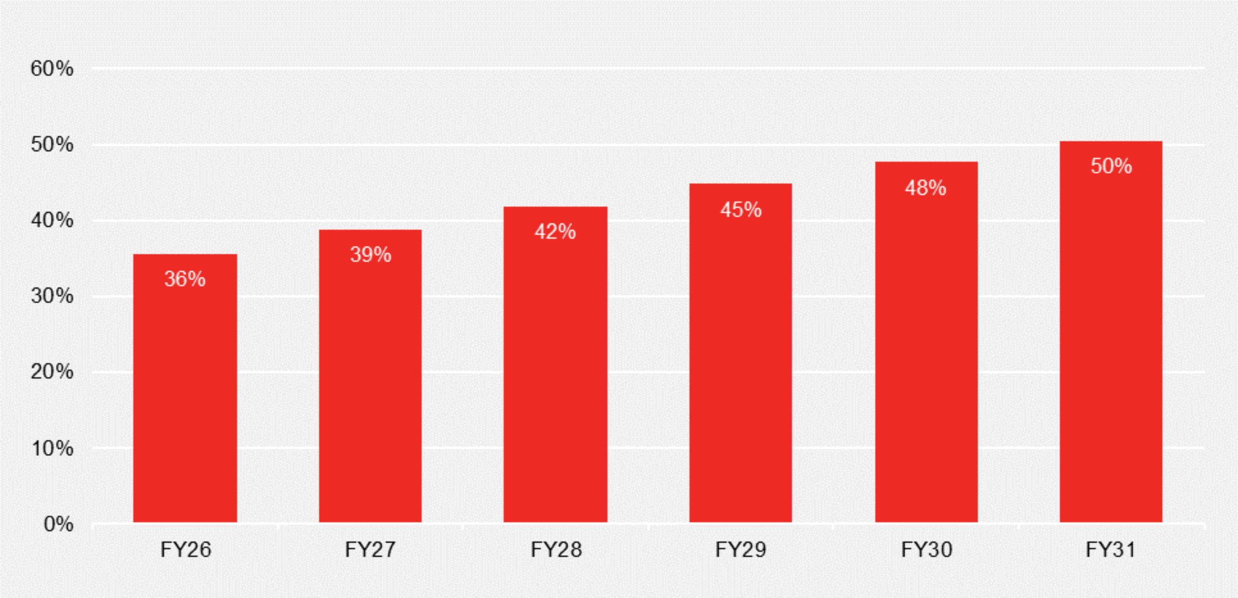
The Victorian Government informed us that they don’t support mandatory assignment to the ToU tariff. They support the current assignment rules which would result in the number of residential customers on a ToU tariff gradually increasing over time.

We therefore propose to:

- reassign all ToU customers to the new ToU tariff from 1 July 2026 and close the existing ToU tariff
- retain our current assignment rules to a ToU tariff
- continue to allow customers on the single rate tariff to opt into the ToU tariff
- continue to allow customers on the ToU tariff to opt out to the single rate tariff unless they have a dedicated EV charger
- allow any customer to opt into or out of the CER tariff.

Figure 7.7 shows the forecast proportion of residential customers on our ToU network tariff, assuming the number of customers opting in are the same as the number of customers opting out.

FIGURE 7.7 FORECAST PROPORTION OF RESIDENTIAL CUSTOMERS ON TOU NETWORK TARIFF



We propose to run campaigns to encourage residential customers to optimise their energy bills by switching to a retail ToU tariff and matching their energy usage to low price periods.

Static and flexible export products

We are proposing to offer a static export limit and flexible export limit for residential solar customers. We see no need for our network tariffs to distinguish between static and flexible export customers. They will have the choice of the single rate, ToU or CER tariffs.

The CER tariff is the only residential tariff with an export charge, but the CER tariff is voluntary. We don’t expect to recover much export charge revenue from the CER tariff and therefore the costs of implementing our flexible export product will be funded by all customers.

7.1.3 Setting tariff rates

Time-of-use

Our current ToU tariff has a peak to off-peak price ratio of 4:1. To minimise bill impacts for customers who are moved from the existing to new ToU tariff, we propose to retain a peak to off-peak price ratio of 4:1 and to price the solar soak at about 1 c/kWh.

Each year over the current regulatory period we have priced the ToU tariff an additional one per cent less on average relative to the single rate tariff, as per our tariff structure statement. By 2025–26, the ToU tariff will be priced to be on average five per cent less than the single rate tariff.

We propose to continue to price the ToU tariff an additional one per cent less on average each year over the 2026–31 regulatory period. By 2030–31 the ToU tariff would then be on average ten per cent less than the single rate tariff.

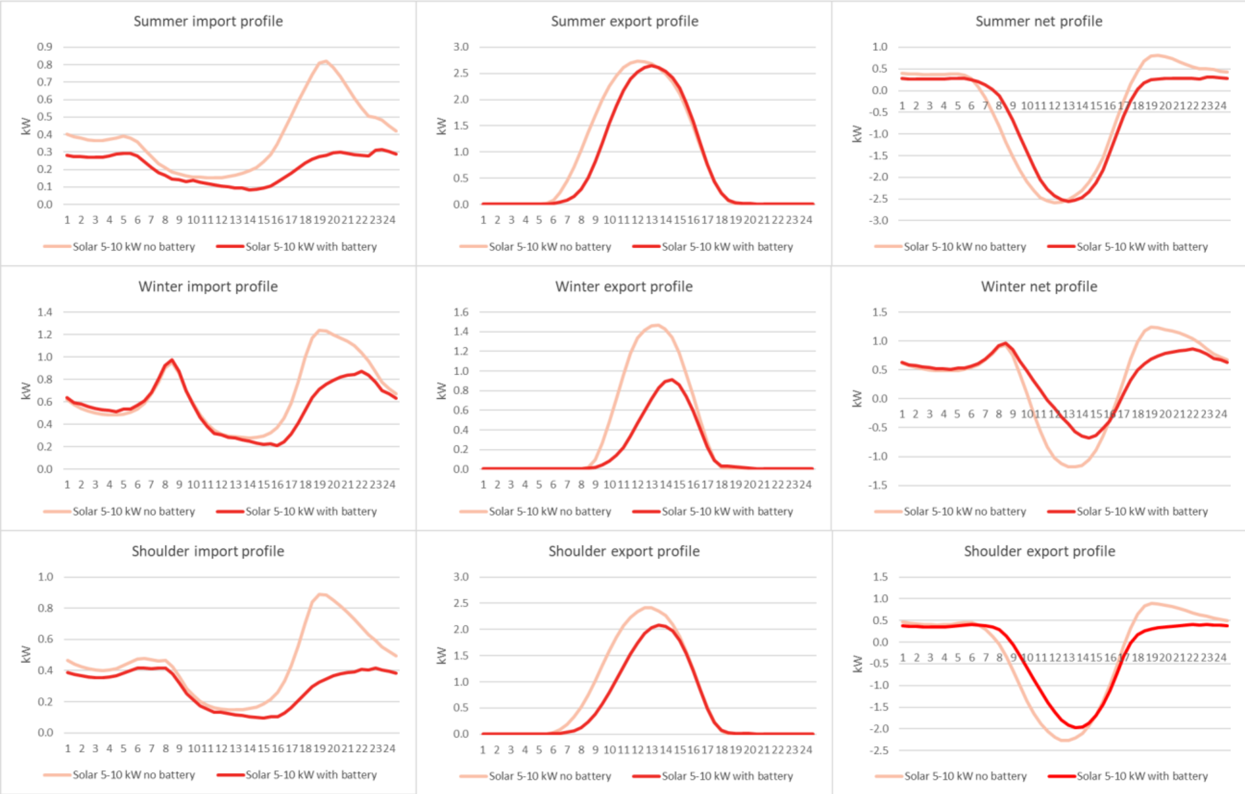
CER tariff

Our objective is to structure and price the CER tariff so that it:

- is attractive to customers with storage e.g. home battery or vehicle-to-grid
- is not attractive to other customers
- does not embedding new cross subsidies

Figure 7.8 compares the profiles of solar customers with and without battery with solar inverter capacity between 5 and 10 kW over 2023-24.

FIGURE 7.8 5 TO 10 KW SOLAR CUSTOMERS WITH AND WITHOUT A BATTERY



We expect that the underlying consumption and generation of these two cohorts to be similar. Customers with 5 to 10 kW solar inverters and a battery:

- export 3,820 kWh pa during the 11am to 4pm period, excluding winter, when export charges will apply under the CER tariff
- export 419 kWh pa less than customers without a battery from 11am to 4pm which is about 1 kWh per day, yet a typical battery capacity is 10 kWh
- import 777 kWh pa less than customers without a battery from 4pm to 9pm - the reduction in peak import charges will be realised on the ToU tariff
- export 92 kWh pa more than customers without a battery from 4pm to 9pm during the months when export credits apply (summer and winter).

This observed battery operation falls far short of optimised behaviour for our proposed CER tariff considering that the estimated average battery storage capacity is over 10 kWh for this cohort.

Designing a CER tariff which will be sufficiently attractive is challenging because:

- the CER tariff is opt-in from the ToU and flat tariffs which don’t charge for exports, but the CER tariff does, and even customers with optimised battery operation will likely have significant exports from 11am to 4pm
- there will always be a stronger incentive to offset consumption in the peak period rather than export electricity in the peak period. The network LRMC in the peak period of about 8 c/kWh is far less than ToU peak retail rate of more than 30 c/kWh. The benefit of offsetting consumption in the

peak period is realised on the TOU tariff – solar and battery customers don't need to move to a CER tariff to realise this benefit

We propose the following adjustment to the new ToU tariff for the CER tariff:

- **11am-4pm export charge**: our network export LRMC cost is 1 c/kWh and we propose to set our export charge at a similar level in the non-winter months with no residual cost recovery. We propose a BEL of 1 kWh per day.
- **4pm-9pm export credit**: the export credit should be no more than the LRMC otherwise we will embed a cross-subsidy. The LRMC in summer/winter is 8 c/kWh and we propose an export credit of about 7 c/kWh in the summer/winter months.
- **peak/off-peak ratio**: we propose to increase the peak/off-peak ratio in summer/winter which will benefit flexible customers who should consume less in peak periods and more in off-peak periods.

Controlled load tariff

Controlled loads could be switched on in the solar soak period but will still require some heating in off-peak times. We propose to set the controlled load rate at a similar level to our TOU tariff saver rate.

7.1.4 Bill impacts of our proposal

Figure 7.9 shows the average bill impact on different personas across the five Victorian distributors of moving existing ToU customer to the new ToU tariff structure. On average, solar customers are marginally worse off and non-solar customers marginally better off.

FIGURE 7.9 BILL IMPACTS OF MOVING EXISTING TOU CUSTOMERS TO THE NEW TOU

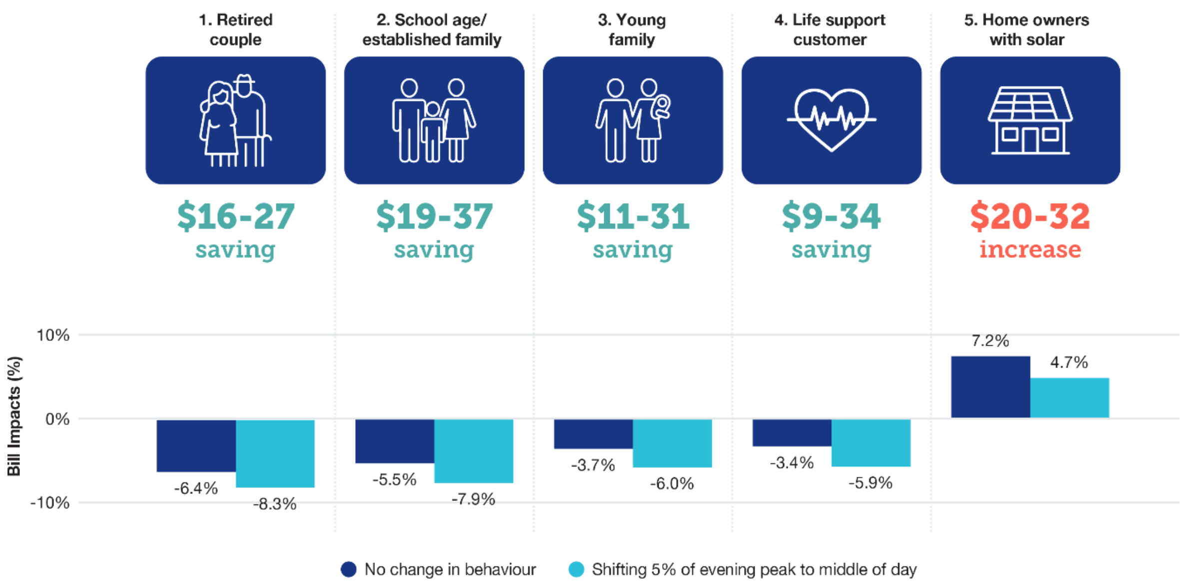
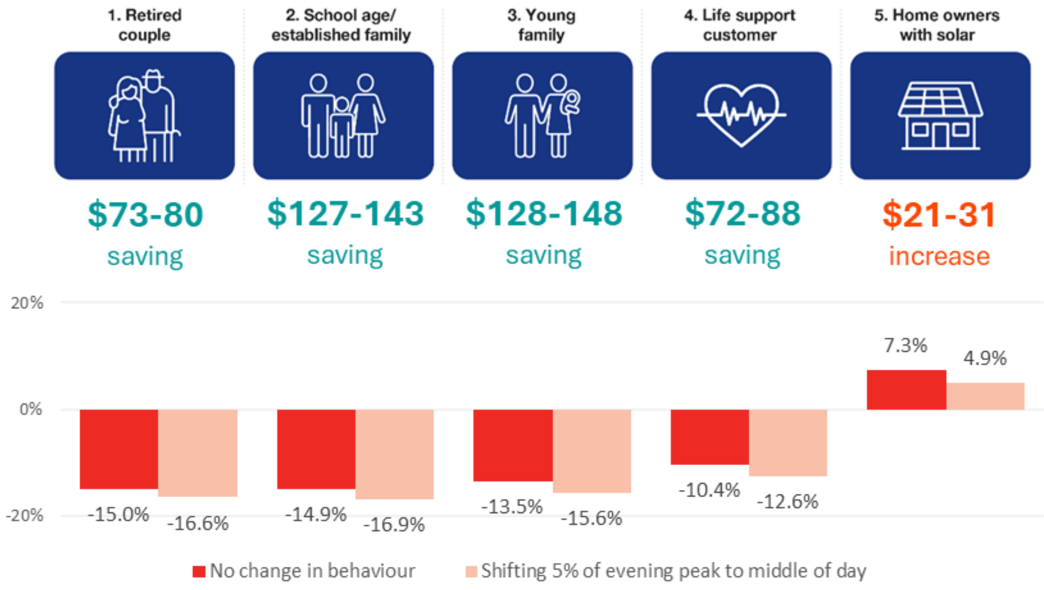


Figure 7.10 shows the average bill impact using the same personas but only comparing the impact of moving from Powercor's 2026-27 indicative single rate tariff to Powercor's new ToU tariff. On average, solar customers are worse off and non-solar customers better off on the new TOU tariff.

FIGURE 7.10 BILL IMPACTS OF FLAT RATE CUSTOMERS MOVING TO NEW TOU



All residential customers, except customers with fast EV chargers, can choose between a flat, ToU or CER tariff. Based on our 2026/27 indicative prices, we have calculated the network charge for average residential customer types for each of the three proposed residential tariffs using 2026-27 indicative rates and 2023-24 average Powercor customer consumption and export profiles (except battery responsive profile which is a hypothetical battery operation overlayed on the average solar customer profile). All solar customers used in this analysis have an inverter size between 5 and 10 kW.

FIGURE 7.11 NETWORK CHARGES BY RESIDENTIAL TARIFF

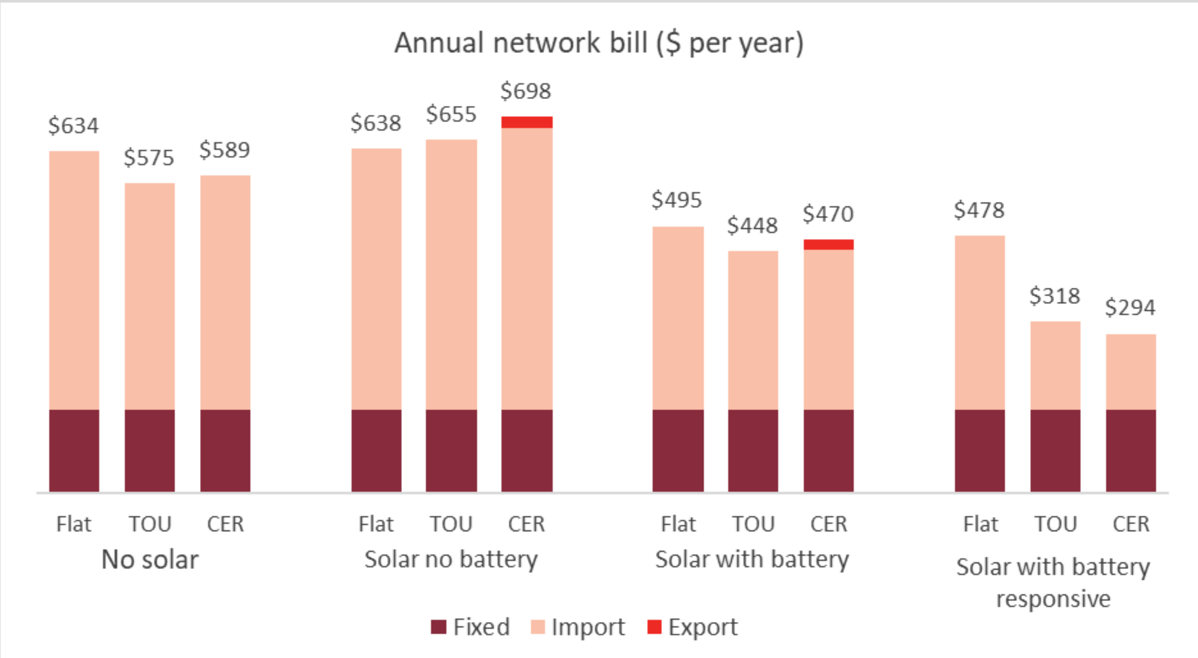


Figure 7.11 shows that:

- the average non-solar customer will be better off on a TOU tariff which is expected since the TOU tariff has been priced slightly cheaper than the flat tariff for the average customer
- the average 5-10 kW solar customer without battery is better off on a flat tariff because they have a higher proportion of consumption in the peak and off-peak periods
- the average 5-10 kW customer with battery with current battery operation is better off on the TOU tariff because they are able to reduce consumption in the peak period. They are not better off on the CER tariff because they incur export charges but only realise a small amount of export credit
- a hypothetical 5-10kW customer with battery with a profile that responds to the CER tariff is better off on the CER tariff.

Every individual customer has their own unique consumption and export profile and the average outcomes shown in Figure 7.11 won't necessarily apply to individual customers. Additionally, customers only pay retail tariffs which can differ between retailers in structure and relative price levels. Individual customers should use retail tariff comparison websites to assess which tariff is best suited to their consumption and export profiles.

7.1.5 Encouraging residential customers onto cost-reflective retail tariffs

Customers with EVs or CER, and those who use more electricity during the day or can change their behaviour, can benefit from our proposed ToU tariff. We plan to run campaigns to encourage residential customers to optimise their energy bills by switching to a retail ToU tariff and matching their energy usage to low price periods.

7.1.6 Contingent triggers

Generally, we are very cautious about proposing contingent triggers due to:

- the difficulty of trying to anticipate a specific potential change and defining a contingent trigger
- the potential costs that would be imposed on retailers' billing systems and customer communication should a tariff be changed within a regulatory period
- the strong stakeholder desire to maintain tariff structure alignment across the Victorian distributors.

The Victorian distributors originally proposed that the peak period end at 10pm, but we received strong opposition to this change. However, should EV take up be higher than expected and there is a tendency to start charging immediately after the peak period, we could experience a new residential peak after 9pm. We therefore proposed a contingent trigger to shift the peak period to 10pm in our tariff directions paper.

Since the Victorian distributors have aligned their ToU network tariff charging periods as requested by stakeholders, any contingent trigger should apply across all five Victorian distributors. This makes defining and monitoring a trigger more difficult and there is no unanimous support for a contingent trigger. Therefore, we are no longer proposing a contingent trigger.

7.1.7 Tariff trials

We anticipate commencing residential tariff trials in the next regulatory period, but no trial is yet scoped.

7.2 Small business

Small business customers are currently defined as non-residential customers consuming no more than 40MWh per annum. The Victorian distributors have aligned their small business tariff structures in the current regulatory period which are shown in table 7.3.

TABLE 7.3 CURRENT SMALL BUSINESS TARIFF STRUCTURES

CHARGE TYPE	SINGLE[1]	TIME OF USE[2]	DEMAND[3]
Fixed	✓	✓	✓
Anytime energy	✓		✓
Peak energy		✓	
Off-peak energy		✓	
Maximum demand			✓

(1) Under a single-rate structure, usage charges, measured in kilowatt-hours (kWh), do not vary with the time of day.
(2) The Time of Use (ToU) structure has a high usage charge during the peak period from 9am to 9pm workdays, and a low usage charge at all other times
(3) The demand tariff structure has a usage charge that does not vary with the time of day, and a demand charge that reflects the maximum monthly 30-minute demand from 10am to 6pm workdays with rates that vary by season

Table 7.4 shows that there are roughly an equal number of small businesses on the single rate and ToU tariffs, and only one per cent of customers are on the demand tariff.

TABLE 7.4 NUMBER OF CUSTOMERS ON EACH SMALL BUSINESS TARIFF

TARIFF TYPE	CUSTOMERS	PROPORTION
Single	43,507	47%
ToU	48,042	52%
Demand	1,245	1%

7.2.1 Tariff structure

We have consistently heard that we need to design small customer network tariff structures assuming that they would be mirrored in retail tariff structures.

We have also consistently heard that small customer tariff structures should continue to be simple. We interpret this to means that small business customers need to be able to understand their retail tariffs, including having access to the simplest tariff (single rate).

We have also heard that we are expected to have efficient tariff which adapt to the energy transition.

We must balance the desire for simplicity with cost-reflectivity which will result in more efficient use of the network.

Single rate

As with residential tariffs, we propose to retain a single rate tariff for small business customers.

Time-of-use tariff

Figure 7.12 shows that small businesses on average consume less energy on weekends compared to weekdays. They also consume less on public holidays.

Our existing small business ToU tariff peak period only applies on workdays; we propose to retain this.

FIGURE 7.12 AVERAGE BUSINESS CONSUMPTION BY DAY (KWH PER CUSTOMER)

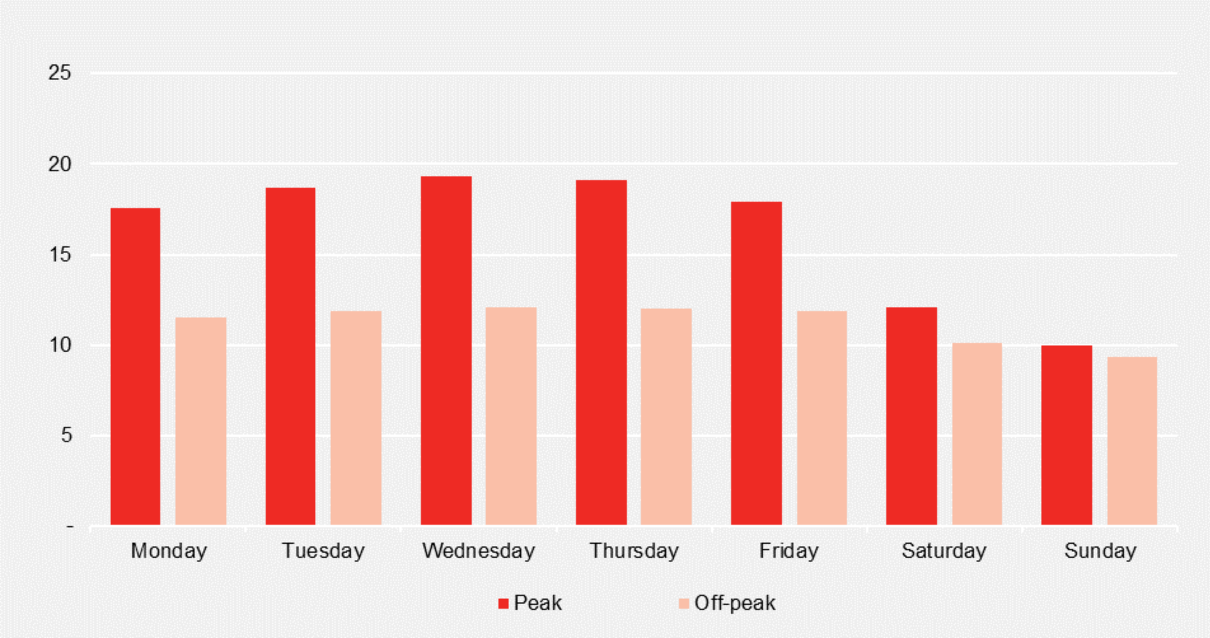
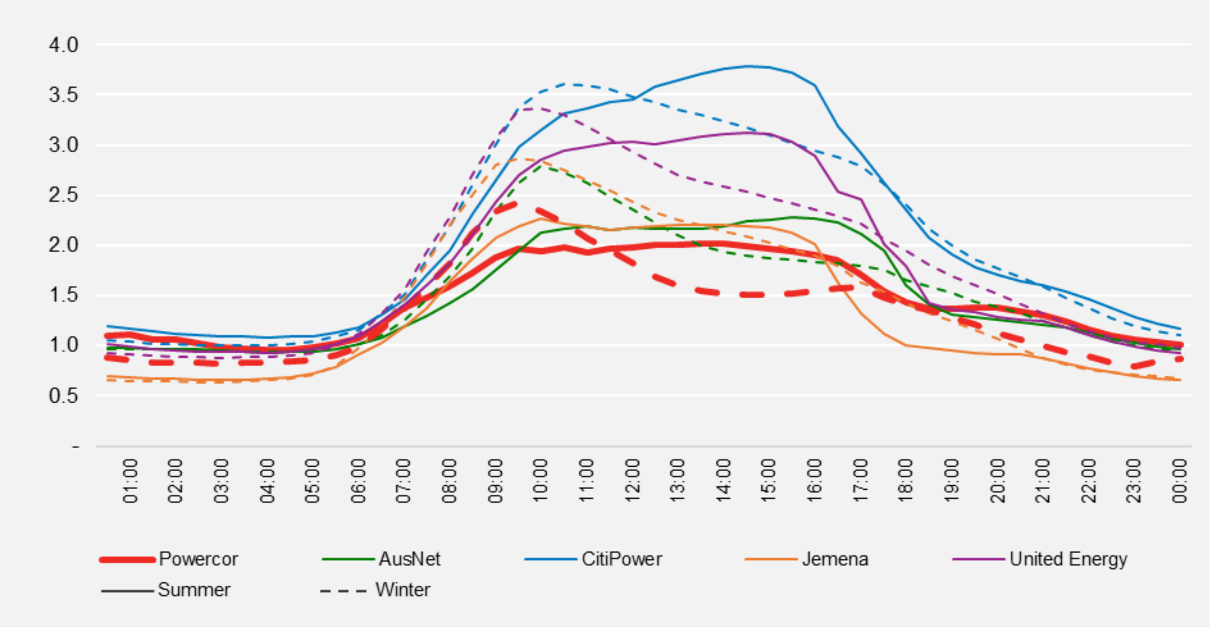


Figure 7.13 shows small business peaks occur any time during the day depending on the network.

FIGURE 7.13 SMALL BUSINESS LOAD PROFILES ON PEAK DAYS (KW PER CUSTOMER)



Note: Peak day imports minus exports; local time. Summer 17 February 2023; winter 20 July 2022

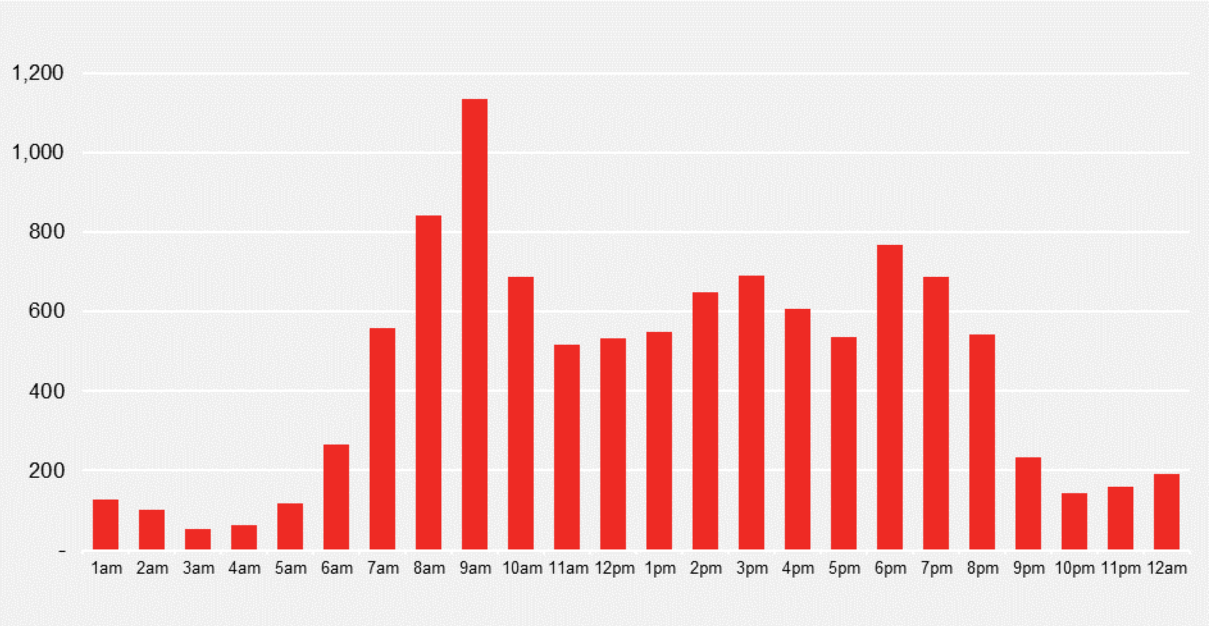
If we were to retain alignment of small business network tariffs without seasonality, then the peak period would ideally be set to 8am–6pm workdays to cover load profiles on network infrastructure which predominantly supplies small businesses. However, figure 7.3 shows that zone substations higher up in the network typically peak between 4pm–8pm. To cover all network infrastructure that supplies small businesses, the peak period should be 8am–8pm workdays. The peak period of the current small business ToU tariff is 9am–9pm.

In our tariff directions paper, we asked stakeholders for their views about whether we should shift the peak period earlier but received no responses to this question. We don't think that shifting the peak period by one hour warrants creating a new tariff which every small business retailer would need to implement and communicate to customers.

Some stakeholders have responded to our small business consultation paper asking for a saver (solar soak) period to be added to the small business ToU tariff in the middle of the day. The aggregate small business profiles in figure 7.13 indicate that small business demand in the middle of the day is close to the time of peak demand, and the annual summer peak occurs in mid-afternoon.

Figure 7.14 shows that 3,030 (28 per cent) of our substations supplying businesses peak during the 11am–4pm saver period. A saver period could exacerbate peak demand of these substations by encouraging more usage and therefore we are not proposing a small business ToU saver period.

FIGURE 7.14 TIME OF MAXIMUM DEMAND FOR OUR SUBSTATIONS SUPPLYING BUSINESSES



Demand

While not many of our customers have been transferred by their retailer onto a demand tariff, other Victorian networks have seen a higher proportion transferred. We therefore propose to retain the small business demand tariff.

CER tariff

We are not proposing to introduce a CER tariff for small business. We believe the current ToU and demand tariffs already provide the right pricing signals for small businesses with CER. Our small business peak pricing:

- discourages small businesses from charging an EV in the day which could exacerbate small business peak demand
- encourages small businesses to use energy from their solar or batteries during the day to offset their usage and maximum demand.

7.2.2 Pricing

The ratio of revenue collected from small business fixed charges is only 14 per cent of total network revenue collected from small businesses.

We propose to increase the proportion of revenue recovered from fixed charges because:

- small business customers with solar are not making a fair contribution to network costs because of the high proportion of revenue avoided through reduced energy consumption
- most of our costs are sunk costs
- long run marginal cost comprises no more than 26 per cent of efficient costs, leaving at least 73 per cent of efficient costs being residual costs
- small customers have told us that they want network charges to be more stable, and network charges would be more stable if less was recovered through variable charges and more through fixed charges.

We propose to increase small business fixed charges and reduce small business usage charges to increase the proportion of revenue recovered by fixed charges to 30 per cent by the end of the next regulatory period.

7.2.3 Tariff assignment

The five Victorian distributors currently align their small business electricity network tariff assignment criteria which are as follows:

- small business customers are assigned to the default ToU tariff when:
  - connecting as a new connection
  - a new or upgraded solar, or battery is installed
  - supply is upgraded to three-phase
  - a small business installs a fast EV charger
- a small business customer on the:
  - single-rate tariff may request to be reassigned to the default ToU or demand tariff
  - default ToU tariff may request to be reassigned to the single-rate or demand tariff, except for customers with EVs who cannot be assigned to a single-rate tariff
  - demand tariff may request to be reassigned to the single-rate or ToU tariff, except for customers with EVs who cannot be assigned to a single-rate tariff.

7.2.4 Bill impacts

Since we are not proposing any changes to our small business tariffs or tariff assignment rules, there are no bill impacts.

7.2.5 Contingent triggers

For the same reasons stated for residential customers, we do not propose any contingent triggers.

7.2.6 Tariff trials

We expect a proliferation of low voltage EV charging sites on our network, such as pole-mounted EV chargers. We do not yet have any experience with their load profiles and needs and therefore are not ready to propose a formal tariff.

This customer class is well suited to trial tariffs, particularly as distribution revenue is not expected to be material.

7.3 Unmetered supplies

In August 2024 the AEMC made a National Electricity Amendment (Unlocking CER benefits through flexible trading) Rule 2024. This new rule FTA rule allows for a new type 9 metering for in-built measurement devices such as smart cells for street lighting. Type 9 metering can only be used at primary connection points for street lighting and street furniture. Most street lighting and street furniture will currently be type 7 metered which means they don't have a physical meter – their consumption is calculated using load tables. Their network tariff is the 'unmetered supplies' tariff. We intend to change the name of the tariff to 'Type 7 or 9 metering' so that when a load moves from type 7 to type 9 metering, they stay on the same network tariff.

7.4 Medium business

Medium business customers are currently defined as non-residential customers with a maximum demand below 120 kVA and consumption greater than 40 MWh per year.

Our medium business tariff structures in the current regulatory period are shown in table 7.5.

TABLE 7.5 CURRENT MEDIUM BUSINESS TARIFF STRUCTURES

CHARGE TYPE	DEMAND[1]	OPT-OUT[2]
Fixed	✓	✓
Anytime energy	✓	
Peak energy		✓
Off-peak energy		✓
Maximum demand	✓	

(1) The demand tariff structure has a usage charge that does not vary with the time of day, and a demand charge that reflects the maximum monthly 30-minute demand from 10am to 6pm workdays which has rates which differ by season

(2) The opt-out tariff allows customers consuming less than 160 MWh pa to opt out of a demand tariff to a ToU tariff with peak prices from 10am to 6pm workdays, and a low usage charge at all other times

This is the smallest class of business customer where a tariff with a demand charge is the default tariff. We believe that having monthly demand reset and restricting the demand measurement period to 8 hours on workdays is the least onerous type of demand charge.

To align with the opt out threshold, we proposed to set the upper threshold for medium business to 160 MWh pa. This is further discussed in the next section.

The option to opt out of a demand charge if consumption is less than 160 MWh per year provides an opportunity for business customers with low utilisation, such as EV charging stations, to establish their businesses. This option has received strong stakeholder support.

We don't see any reason to make any other changes to our medium business tariffs especially since no stakeholders have requested a change.

7.5 Commercial and industrial

Commercial and industrial customers are currently defined as non-residential customers with a maximum demand above 120 kVA. They include customers connected to the low voltage, high voltage, and sub-transmission levels of the distribution network.

Generator and storage customers are discussed in the next section.

Our commercial and industrial business tariff structures in the current regulatory period are shown in table 7.6.

TABLE 7.6 CURRENT COMMERCIAL AND INDUSTRIAL TARIFF STRUCTURES

CHARGE TYPE	DEMAND[1]	OPT-OUT[2]
Fixed		✓
Anytime energy		
Peak energy	✓	✓
Off-peak energy	✓	✓
Maximum demand	✓	
Incentive demand	✓	

(1) The demand tariff structure has a peak usage charge from 7am to 7pm workdays, an off-peak usage charge at all other times, a 12-month rolling demand charge measured 7am to 7pm workdays with minimum demand of 120 kVA for low voltage connections, 500 kVA for high voltage connections and 5,000 kVA for sub-transmission connections, and a monthly incentive demand charge measured either from 4pm to 7pm workdays or 1pm to 4pm workdays only from December to March. Incentive demand is not applied for sub-transmission customers

(2) The opt-out tariff allows customers consuming less than 160 MWh pa to opt out of a demand tariff to a ToU tariff with peak prices from 10am to 6pm workdays, and a low usage charge at all other times

Table 7.7 summarises key feedback received from commercial and industrial customers and our response to their feedback. Storage is dealt with separately in the next section.

TABLE 7.7 OUR RESPONSE TO KEY FEEDBACK RECEIVED

FEEDBACK RECEIVED	OUR RESPONSE
Many customers are largely unaware of their current network tariff structure and some customers asked for more straightforward and easily comprehensible educational materials that explain their network tariff structures in simple ‘customer-friendly’ terms.	We will publish improved online material to explain our network tariffs.
Many businesses expressed their lack of flexibility to change energy consumption behaviour.	We will not impose overly complex or punitive network tariffs.
Generally, want greater flexibility to vary demand to complement their operating models.	This suggested that customers want the demand measurement period to be made shorter but based on the previous comment the period should be static. We could only do this by moving to locational pricing which we believe will be perceived to be inequitable and add further complexity to network tariffs.
Want to be rewarded for behaviour which assists the network. We presented three options to customers (1) critical peak pricing, (2) tailored pricing, and (3) network support agreements. There was a leaning towards network support agreements, with critical peak pricing perceived to be punitive by some.	Customers with flexible load located in areas of the network which are constrained will have the opportunity to be rewarded for behaviour which assists the network through network support agreements. Customers who enter into a flexible connection agreement will be able to access a flexible connection tariff (see next section).
EV charging stations do not want to pay a demand charge.	EV charging stations which are likely to consume less than 160 kWh pa can opt out of a tariff with a demand charge. If their consumption consistently exceeds 160 MWh pa they will be moved to a demand tariff.
Need a horizon of electricity cost changes (annual increase/decrease) for their business budgeting; for example, a 5-year moving horizon.	Commercial and industrial network tariffs comprise a material proportion of transmission charges. We have no insight into future transmission charges and are therefore unable to provide a reliable 5-year moving horizon.

7.5.1 Tariff structure

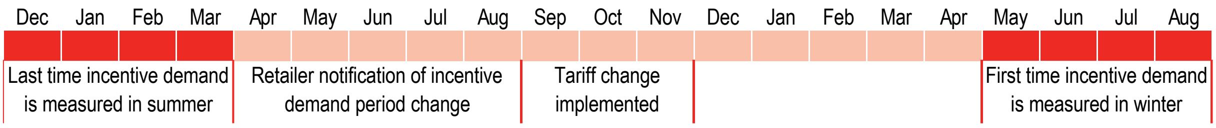
We propose no change to the structure of commercial and industrial tariffs because we think they strike the right balance between cost-reflectivity and simplicity and maintain tariff stability for our customers. Furthermore, we only just completed the transition to include an incentive demand charge in 2024–25.

The incentive demand charge, currently only charged in summer months, is an important cost-reflective price signal. Customers are currently either assigned an incentive demand period of 1–4pm summer or 4–7pm summer.

However, some parts of our network are winter peaking, and we expect more parts of our network to become winter peaking with the electrification of space heating. Therefore, we now propose to include a third incentive demand period from 4–7pm in the winter months of May to August.

We had several retailers ask about the timing of the change to a winter incentive demand period for a customer currently assigned to a summer incentive demand period. Figure 7.15 demonstrates that an affected customer would receive a small benefit in that incentive demand would be deferred by six months, and the customer could receive notification about the change at least eight months prior to the first winter demand period.

FIGURE 7.15 TIMING OF INCENTIVE DEMAND PERIOD CHANGE TO WINTER



7.5.2 Tariff assignment

We propose to change the threshold for commercial and industrial customers from 120 kVA to 160 MWh per annum to:

- align to the demand tariff opt-out threshold
- facilitate easier monitoring that customers remain on an appropriate tariff for both us and retailers—it is easier to monitor consumption rather than maximum demand.

This means that customers consuming greater than 160 MWh per annum (excluding flexible connections discussed in the next section) can only be assigned to one network tariff and there is no tariff choice.

7.6 Flexible connections

Over the last three years, we have held numerous conversations with storage proponents about network tariffs. The capacity of proposed storage has ranged from 120 kW to 120 MW.

Storage proponents have included non-profit organisations, retailers, existing generators, existing load customers and new commercial entrants. Along the way, we have introduced four different storage trial tariffs which are explained in table 7.8.

TABLE 7.8 OUR CURRENT STORAGE TRIAL TARIFFS

TRIAL TARIFF	STRUCTURE	REASON
HV storage	Peak demand period narrowed to 4-9pm and minimum demand removed	This was our first storage trial tariff which was a modification of our HV tariff
Generator storage	12-month rolling kW demand charge measured 4pm–9pm or 11am–4pm and 2 c/kWh anytime energy charge	This was an enhanced version of our HV storage tariff, also targeted at auxiliary power used by generators
Community battery ToU	Two-way ToU tariff with charges and rebates	Provides an incentive to charge in the middle of the day and discharge in the early evening
Distributor LV battery	Fixed daily charged scaled to the size of the battery	The thinking was that because the distributor owns the battery, it does not need ToU price signals

These interactions and trial tariff learnings have helped us appreciate the diversity of storage circumstances and their resulting profiles, for instance:

- stand-alone storage to maximise profit
- storage with the primary objective of reducing carbon emissions
- storage co-located with generation
- storage co-located with rooftop solar and EV charging
- from 2-hour to 18-hour duration storage.

These learnings culminated in our release of a storage integration consultation paper in February 2024. Figure 7.16 below illustrates our initial view on how flexible connections and network service agreements would result in less complex and more affordable storage tariffs.

FIGURE 7.16 STORAGE INTEGRATION APPROACH AND BENEFITS

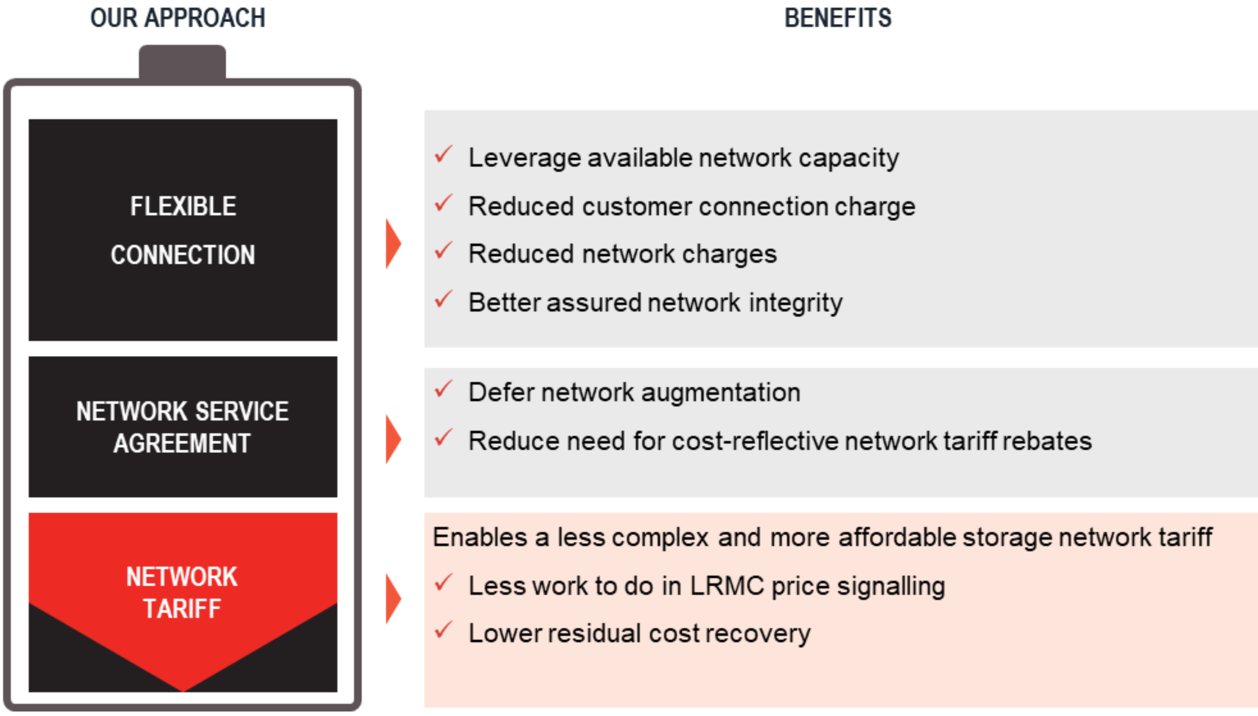


Table 7.9 summarises key feedback we received and our responses.

TABLE 7.9 OUR RESPONSE TO KEY FEEDBACK RECEIVED

FEEDBACK RECEIVED	OUR RESPONSE
Co-location of BESS and EV charging with smart-charging capability provides an opportunity to both time shift energy and reduce peak demand from home EV charging. The definition of storage should be based on the nature of the connection, not on the technology behind it.	We agree and consider that the tariffs we are considering for storage apply to any sites which meet the definition of a flexible connection. See discussion after this table.
Mirror the charge and rebate rates, for example, if the peak period charge for imports is 20 c/kWh then the peak period rebate for exports should be 20 c/kWh.	Flexible connections located in areas where network support is required will have the opportunity to be rewarded through network support payments outside network tariffs. A mirrored tariff would overpay a flexible connection for network support. Additionally, energy charges also recover residual costs and therefore the residual cost proportion of energy charges should not be mirrored.
The assumption that distribution LRMC decrease with higher voltage level may no longer be valid due to the two-way nature of the network.	Most network augmentation is directed at peak demand which will typically occur when two-way flows are low. Therefore, we don't expect that two-way flows will yet have a material impact on LRMC.
Networks should make more information available about where storage would be most beneficial to the network.	Agree, and there are initiatives underway to make more information available.
Networks should make more information available about forecast of the exercise of flexible control in terms of the number, timing and duration of use of flexibility in each area.	The information that we will make available on network opportunities would flag locations and times when flexible control might occur.
Why are avoided transmission credits not available for non-registered generators.	We believe that avoided transmission credits are a cross-subsidy which adds to the costs of load customers, therefore we only pay what the NER requires us to pay.

Upgrades should not be made to make network support redundant, and after any augmentation the network support payments should continue to be honoured until the end of the asset life.	We will apply the least cost solution to relieve a network constraint. If network support could defer augmentation, then network support payments in total should not exceed the value of deferred augmentation.
If the network tariff penalises the provision of network support, then the network tariff cost should be added to network support payments.	Agree.
Network tariffs should not be a barrier to batteries wanting to cycle more than once per day.	The charging structures which we propose do not penalise charging from 9pm–4pm and therefore would allow for multiple cycles in a day.
V2G should not be excluded.	V2G from the home is accommodated by our proposed residential flexible tariff. V2G from non-residential connection which meet the criteria for a flexible connection will not be excluded.
The capacity charge should only be based on demand during peak periods.	The purpose of the capacity charge is to recover residual costs. It is not a price signal.

7.6.1 Eligibility

Some stakeholders have questioned the definition of storage and we have re-considered its definition. We propose to introduce new tariffs for a non-residential 'flexible connection' which we define as follows.

> Flexible connection is demand management actioned through connection agreements such as an agreement to be controlled by our distribution energy resource management system (DERMS)

For the avoidance of doubt, any battery or stand-alone generation connection will be deemed to be a flexible connection. It may also include loads combined with storage such as EV charging combined with battery, and other flexible loads such as hydrogen production facilities but they must have an agreement with us that gives us a level of control over their connection. Flexible tariffs are not intended to be available to business sites with solar that can export to the grid even though the Victorian Emergency Backstop Mechanism requires us to limit their exports at the direction of AEMO. Businesses with solar that can export are still primarily in the business of consuming energy for business operations.

Connection arrangements are evolving and therefore we will need to retain some discretion about eligibility for flexible connection tariffs. We think that there may be circumstances where EV charging sites, particularly on the LV network such as pole mounted chargers, would be appropriately assigned to a flexible connection tariff. We therefore intend to trial placing a limited number of LV charging sites on the small flexible connection tariff in the next regulatory period.

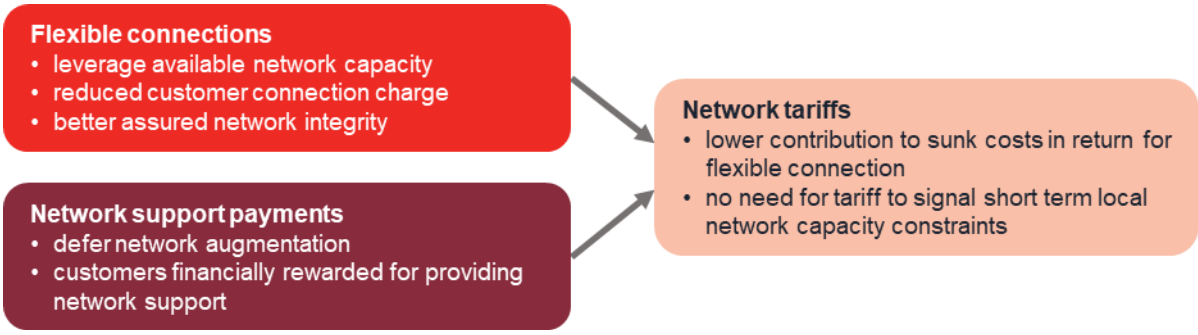
7.6.2 Implication for network tariffs

Flexible connections are a form of enforced dynamic operating envelop with the reward being a lower connection charge and a lower contribution to residual network costs in the network tariff. Flexible connections also remove the need for network tariffs to signal short-term local capacity constraints through network tariff charges for behaviour which exacerbates the constraint.

Network support payments remove the need to signal short-term local capacity constraints through network tariff rewards for behaviour which relieves the constraint.

The benefits of flexible connections and network support payments, and implications for network tariffs, are summarised in figure 7.17.

FIGURE 7.17 IMPLICATIONS OF OUR APPROACH FOR NETWORK TARIFFS



7.6.3 Proposed flexible connection tariffs

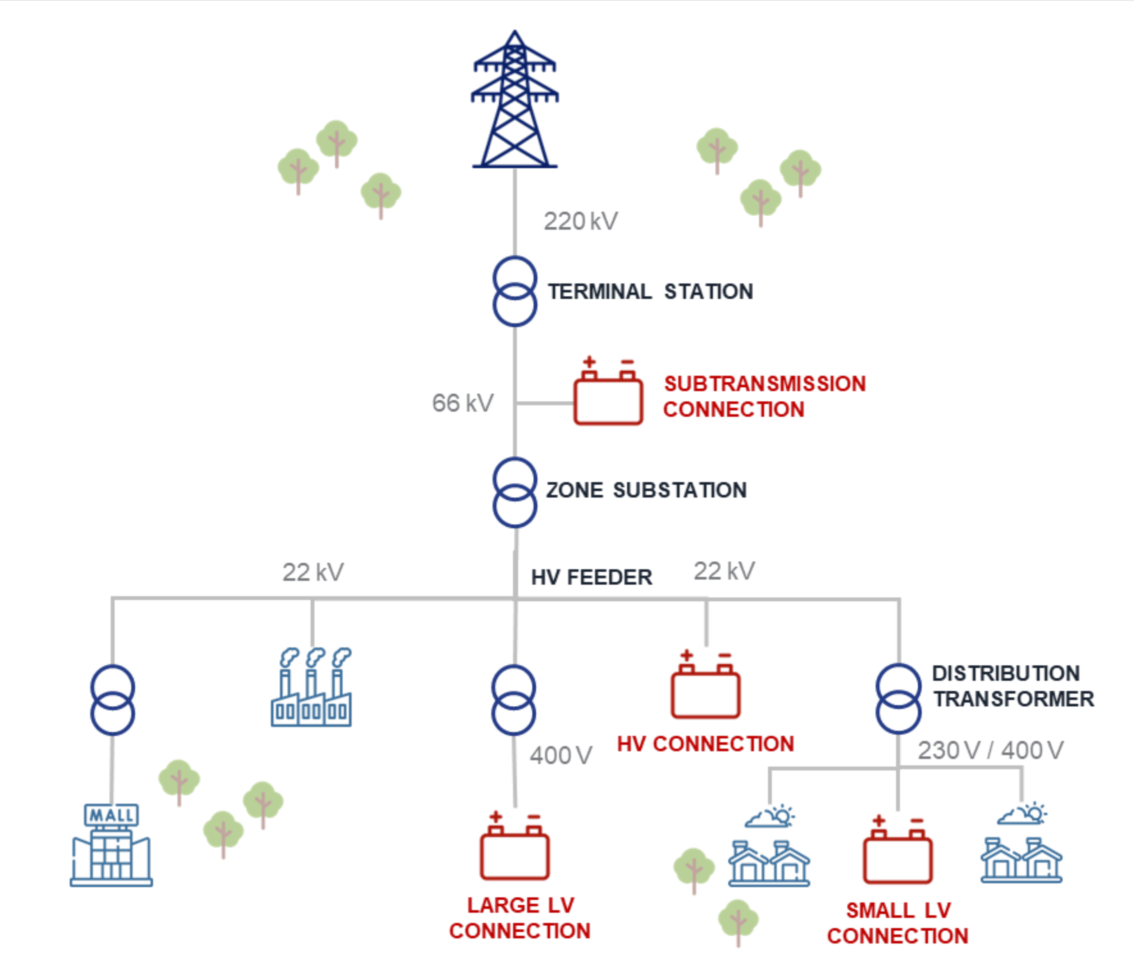
Small LV flexible connections such as community batteries are assumed to be located downstream of a distribution transformer which also supplies residential customers with rooftop solar. Other larger flexible LV connections are assumed to have dedicated transformers and therefore won't be located where they can support residential LV networks.

We propose the following flexible connection network tariffs:

- flexible small LV (less than 240 kVA import capacity)
- flexible large (greater than 240 KVA and less than 30 MVA import capacity)
- flexible TUOS pass-through (30 MVA and above import capacity)

Figure 7.18 provides examples of where different types of flexible connection could be located on our network.

FIGURE 7.18 DIFFERENT LEVELS OF FLEXIBLE CONNECTION



The level at which a flexible connection occurs on our network has implications for the structure of their network tariff.

Flexible connection tariff assignment

Flexible connections will be automatically assigned to the relevant flexible connection tariff, however, these customers will have the choice to transfer to the tariff which would have applied in the absence of the customer being a flexible connection. We don't anticipate any situation where the flexible connection tariff is a higher cost than the alternative.

Recovery of residual costs from flexible connections

The NER states that the total revenue from network tariffs must permit a distributor to recover the expected revenue in accordance with the AER revenue determination. This revenue is recovered through a combination of price signals to incentivise certain behaviour (long run marginal cost) and recovery of sunk costs (residual costs).

We propose that storage should make a fair contribution to residual costs just like any other customer, consistent with the AER and AEMC decisions. The contribution of flexible connections to residual costs should be discounted because they are being subjected to some form of demand management.

Consistent with other network tariffs, we propose that recovery of residual costs per kW of capacity should decrease as the connection voltage increases because less of the distribution network is used to supply higher voltage levels.

A Brattle Group report for the AEMC on the recovery of residual costs suggested that the most efficient way to recover residual costs is through fixed charges.[2]

Consistent with this, we propose to recover residual costs through fixed charges, but we need a way to scale fixed charges to the size of a customer. We propose that residual costs are recovered through an import capacity charge which would ensure that a customer contributes to residual costs proportionately to capacity required from the network. This is consistent with the advice provided by Argyle Consulting and Endgame Economics to AER.[3]

The NER does not allow residual cost to be recovered through export charges and therefore the capacity charge would be based on the amount of import capacity required by the customer. We propose that the capacity charge be based on the 12-month rolling kW import demand. We think that measured demand is better than contract demand since supply capacity may be sized for exports rather than imports and removes the risk of administrative error. Since it is not always optimal for generation to occur at a power factor of unity, we propose that the capacity charge is based on real power (kW) rather than total power (kVA).

Flexible small tariff

Small flexible connections, such as community batteries, are assumed to occur in residential areas. Therefore, we propose the same tariff structure as the residential CER tariff.

Figure 7.19 shows our proposed flexible small tariff structure. Rates would be the same on weekdays and weekends, and all times are in local time.

FIGURE 7.19 FLEXIBLE SMALL TARIFF STRUCTURE

			Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Capacity		$/kW/month												
Off-peak	Import	-												
9pm - 11am	Export	-												
Peak	Import charge	c/kWh												
4pm - 9pm	Export credit	c/kWh												
Saver	Import charge	-												
11am - 4pm	Export charge	c/kWh												

Note: All times are in local time

We propose to have the same tariff structure and rates across CitiPower, Powercor and United Energy. Table 7.10 shows indicative rates for 2026-27.

2 The Brattle Group, Structure of Electricity Distribution Network Tariffs: Recovery of Residual Costs, prepared for the Australian Energy Market Commission, August 2014

3 Argyle Consulting and Endgame Economics, Network tariffs for the distributed energy future, Final paper to the Australian Energy Regulator, June 2022

TABLE 7.10 FLEXIBLE SMALL TARIFF INDICATIVE 2026-27 RATES

TARIFF COMPONENT	MONTHS	TIME	RATE
Capacity charge	all	na	$2.00/kW/month
Peak import charge	Dec-Feb, Jun-Aug	4pm-9pm	7 c/kWh
Peak export credit	Dec-Feb, Jun-Aug	4pm-9pm	7 c/kWh
Export charge [a]	Sept-May	11am-4pm	1 c/kWh
Off-peak	all other times		0 c/kWh

[a] BEL of 1 kWh per day for the same reasons stated for the residential CER tariff.

Figure 7.18 shows bill impacts for the flexible small tariff assuming a community battery of 100kW which charges from 11am to 4pm and discharges from 4pm to 9pm every day of the year with an efficiency of 85%, at different hours of storage. Charges are directly proportional to battery size, for example, a 200kW battery with the same operation will have double the network charges / rebates. Community batteries with more than 2 hours of storage have the opportunity to earn a net credit from the network.

FIGURE 7.20 FLEXIBLE SMALL TARIFF 2026-27 ANNUAL NETWORK CHARGE

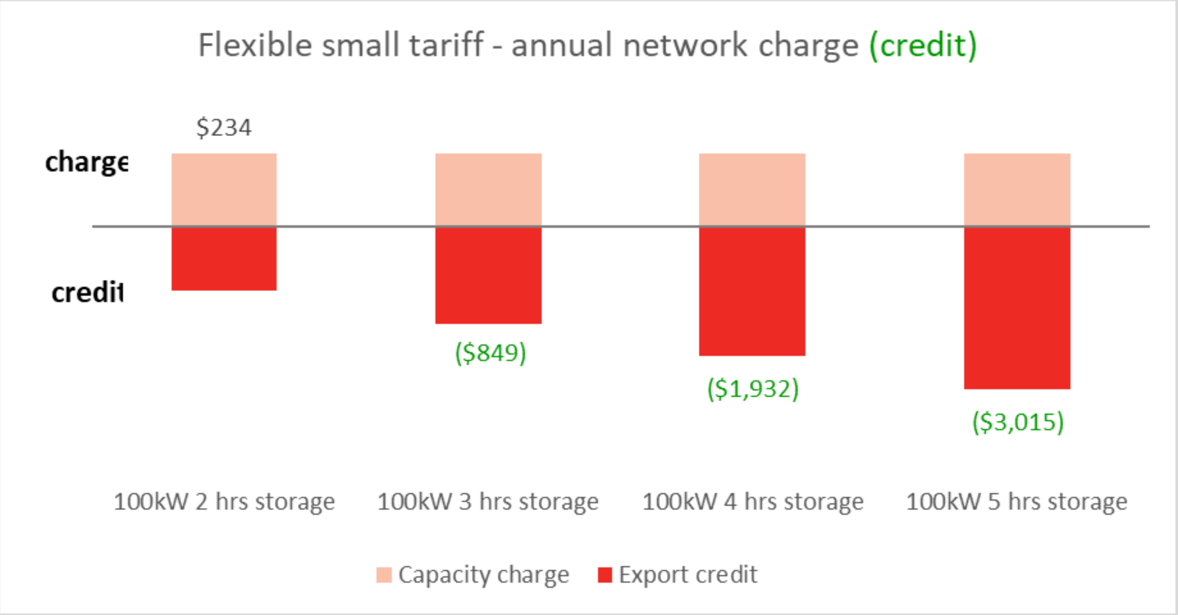
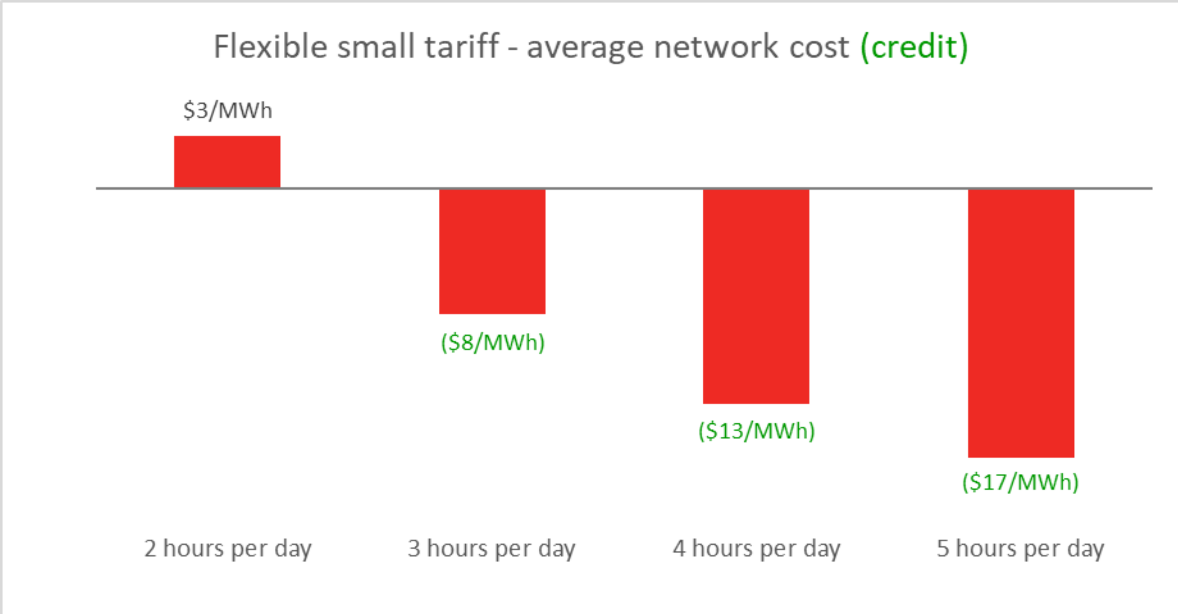


Figure 7.21 shows the average network cost in $ per MWh for different numbers of hours of charging at maximum capacity per day. It once again illustrates that longer duration batteries can expect to earn a net credit from the network.

FIGURE 7.21 FLEXIBLE SMALL TARIFF AVERAGE NETWORK COST



Flexible large tariff

Flexible large connections will impact demand on HV feeders and further upstream network assets which typically peak from 4pm–9pm, and therefore this is the proposed peak period.

We propose to only charge for imports during the peak period with no other import energy charges. Network charges will therefore not be a barrier to storage cycling more than once a day.

Exports are not yet forecast to drive the need for augmentation investment by 2031 on our high voltage network and therefore we do not propose any export charges.

Figure 7.22 shows our proposed flexible large tariff structure. Rates would be the same on weekdays and weekends, and all times are in local time.

FIGURE 7.22 FLEXIBLE LARGE TARIFF STRUCTURE

			Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Capacity		$/kW/month												
Off-peak	Import	-												
9pm - 11am	Export	-												
Peak	Import charge	c/kWh												
4pm - 9pm	Export credit	-												
Saver	Import charge	-												
11am - 4pm	Export charge	-												

Note: All times are in local time

We propose to have the same tariff structure and rates across CitiPower, Powercor and United Energy. Table 7.11 shows indicative rates for 2026-27.

TABLE 7.11 FLEXIBLE LARGE TARIFF INDICATIVE 2026-27 RATES

TARIFF COMPONENT	MONTHS	TIME	RATE
Capacity charge	all	na	$1.25/kW/month
Peak import charge	Dec-Feb, Jun-Aug	4pm-9pm	7 c/kWh
Off-peak	all other times		0 c/kWh

Figure 7.23 shows annual network charges for different sizes of a flexible large connection assuming that the connection does not consume energy between 4pm and 9pm.

FIGURE 7.23 FLEXIBLE LARGE TARIFF 2026-27 ANNUAL NETWORK CHARGE

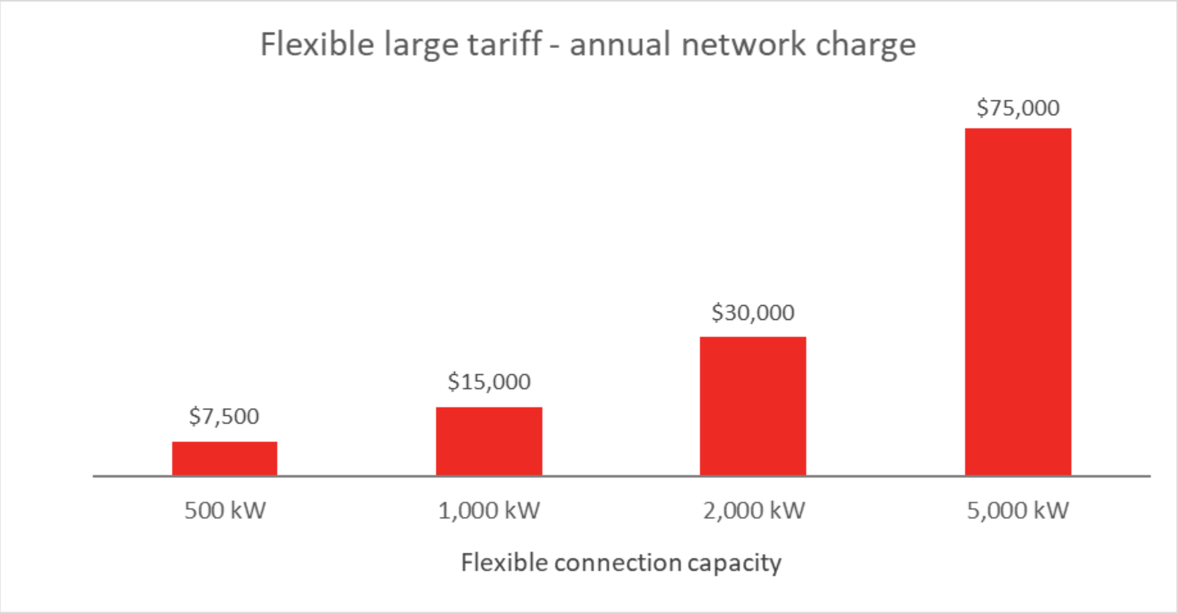
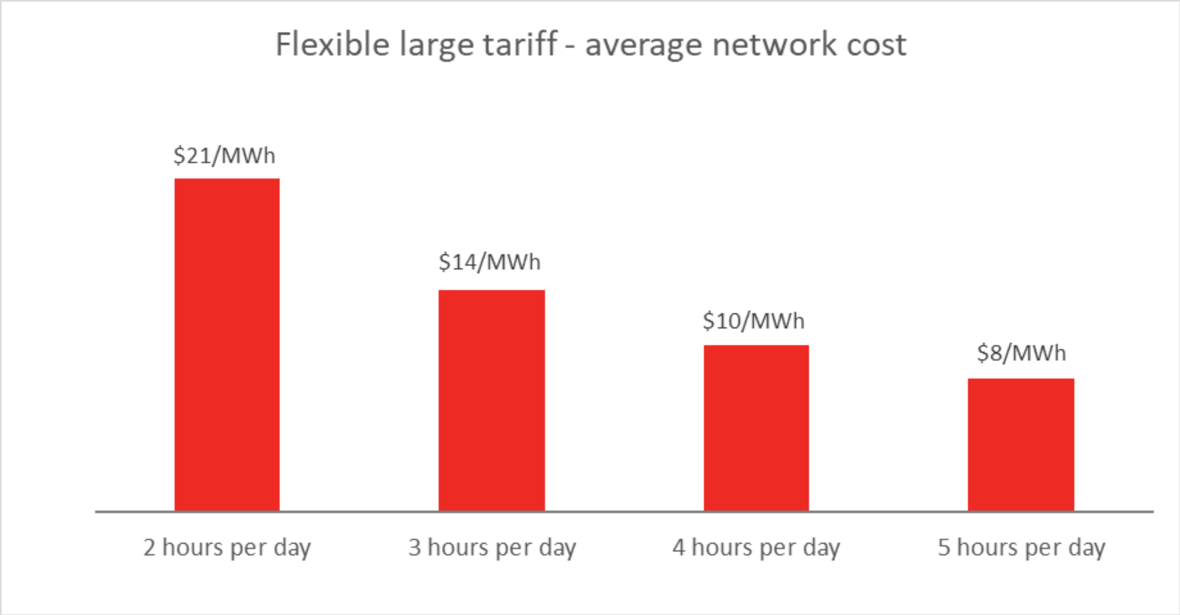


Figure 7.24 shows the average network cost in $ per MWh for different numbers of hours of charging at maximum capacity per day. These costs are small in comparison to the arbitrage profit that a battery can earn from the wholesale market and therefore should have very little impact on their internal rate of return.

FIGURE 7.24 FLEXIBLE LARGE TARIFF AVERAGE NETWORK COST



Flexible TUOS pass-through tariff

Flexible customers with connections above 30 MVA import capacity should be sophisticated enough to understand more complex network tariffs. Additionally, sub-transmission customers connect immediately downstream of a terminal station as shown in figure 7.18, and therefore rely primarily on the transmission network.

We incur transmission charges (TUOS charges) for demand and energy at each terminal station.

We propose that:

- LRMC cost recovery occurs through pass-through of incremental TUOS charges at the relevant terminal station to a flexible connection assuming that all energy consumed by the flexible connection is supplied from the terminal station
- residual costs recovery occurs through a distribution capacity charge calculated as import kVA capacity multiplied by a daily per kVA capacity charge.

Generators, including storage generation, connected under NER Chapter 5 (as an Embedded Generator or a Market Network Service Provider) are eligible for avoided charges for the locational component of prescribed TUOS services (avoided TUOS). We would build this payment into the tariff by providing a credit for avoided TUOS as part of the tariff.

TUOS charges relating to consumption and demand in financial year t are calculated in year t+1 and charged to us in year t+2 as an equal payment each month. We would follow the same timing and therefore any new flexible connection in year t will only incur TUOS charges and avoided TUOS charges from year t+2. Should there be any changes in the way that we are charged for transmission costs, these changes would be passed through to the flexible connection.

Figure 7.25 shows our proposed flexible TUOS pass-through tariff structure.

FIGURE 7.25 FLEXIBLE TUOS PASS-THROUGH TARIFF STRUCTURE

			Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Capacity		$/kVA/month												
Demand	Import charge	$/kW/month												
Demand	Export credit	$/kW/month												
Energy	Import charge	$/MWh												

7.6.4 Tariff assignment

We propose that eligible flexible connections will be assigned to the relevant flexible connection tariff, but flexible connection customers can opt-out to the tariff which would have otherwise been applied had they not been a flexible connection.

We propose that all flexible connections are subject to the same network tariffs irrespective of ownership. Therefore, distributor owned flexible connections would be assigned the same network tariff as any other flexible connection.

7.7 Other tariff issues and complementary measures

7.7.1 Trial tariffs

All our existing trial tariffs will close on 30 June 2026 and table 7.12 shows to which tariff customers on trial tariffs will be moved.

TABLE 7.12 ASSIGNMENT OF EXISTING TRIAL TARIFF CUSTOMERS ON 1 JULY 2026

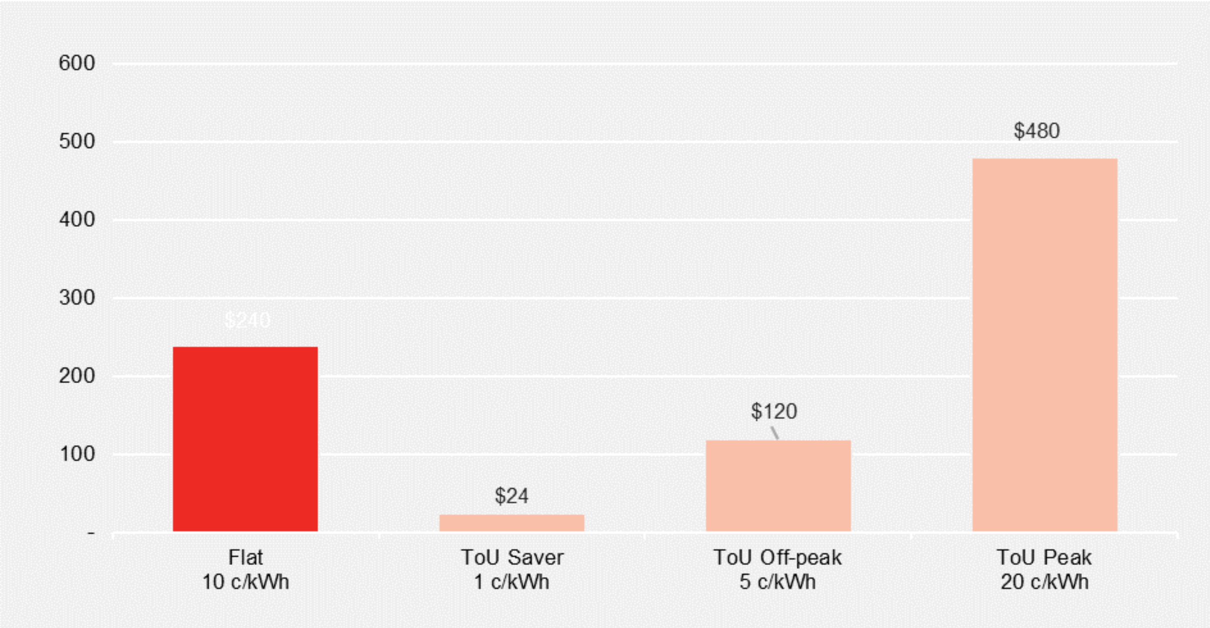
TRIAL TARIFF	NEW TARIFF
Residential daytime saver	Residential ToU
Generator storage	Flexible large
HV storage	Flexible large
Community battery ToU	Flexible small
Distributor LV battery	Flexible small

7.7.2 Electric vehicles

Residential EV charging

Our proposed new residential ToU tariff will provide EV owners with the opportunity to charge their vehicles at low cost. Figure 7.26 shows that the indicative costs of charging an EV at home on the single rate tariff is $240 per year, while this could be reduced to $24 per year on the ToU tariff charging in the saver period.

FIGURE 7.26 INDICATIVE ANNUAL NETWORK COST OF HOME EV CHARGING



Note: Assumes 2,400 kWh pa additional home energy usage

Public EV charging

Public EV charging stations currently generally demonstrate high demand and low utilisation. A demand charge will result in high charges per kWh of EV charging energy used. We will retain our policy of allowing businesses consuming less than 160 MWh pa to opt out of a demand charge which will assist with the establishment of public EV charging in Victoria.

7.7.3 Microgrids

Microgrids are an immature concept with a long way to play out and it would be premature to now settle on a certain network tariff model. We propose to cover any potential microgrid tariff opportunities through tariff trials.

7.7.4 Demand aggregation

A business with multiple locations may want to be charged based on aggregating the meter data across multiple locations. This would have the effect of lowering the overall network demand charge, due to diversity between locations.

We do not allow this type of charging because our network must be designed to meet maximum demand at each location.

7.7.5 Local use of system tariff

Some stakeholders have advocated for a model where customers subscribing to a storage or generation service would be charged a lower network tariff for energy supplied from a nearby community battery or a nearby generator. The argument is that this energy was supplied from nearby and therefore uses less of the distribution network, referred to as local use of system (LUOS) charges.

We have rejected the concept of LUOS as defined above because:

- customers should not be rewarded with a network tariff discount because they have subscribed to a service, rather they should be rewarded for changing their consumption profile in a way that benefits the network

- the same upstream capacity is still required even if the upstream grid is used infrequently. That capacity, and its replacement and maintenance, costs the same whether there is two per cent utilisation or 100 per cent utilisation. Therefore, a LUOS would embed a cross-subsidy with the tariff discount increasing charges for other customers.

7.7.6 Complementary measures

We also propose to step up complementary measures to assist customers choose an appropriate tariff and better understand how they could reduce their energy costs.

Complementary measures include:

- campaigns to encourage residential customers to optimise their energy bills by switching to a retail time-of-use tariff and matching their energy usage to low price periods
- literacy programs focussed on customers who may be at risk of energy poverty
- energy advisory services targeted at assisting communities, welfare agencies and other institutions on bespoke data requests
- more support for our commercial and industrial customers and storage and generation proponents, including improved online resources on how their network charges are calculated.

7.8 Long run marginal cost, stand-alone and avoidable costs

7.8.1 Long run margin cost

Long run marginal cost (LRMC) for both import and exports has been calculated by Oakley Greenwood using input provided by us. Oakley Greenwood's LRMC model is attachment PAL MOD TSS.01 - Long run marginal cost - Jan2025 – Public and their accompanying letter describing the approach is attachment PAL ATT TSS.03 - Long-run marginal cost - Jan2025 – Public.

We have adopted the AIC approach for the purposes of calculating the LRMC because it is commonly used by distribution networks and can use demand and cost forecasts that underpin the regulatory proposal.

Table 7.13 shows the calculated LRMC for imports and Table 7.14 shows the calculated LRMC for exports.

TABLE 7.13 LRMC - IMPORTS

VOLTAGE LEVEL	LRMC ($/KVA) BY VOLTAGE LEVEL	LRMC ($/KVA) BY CONNECTION
Sub transmission	$1.08	$1.08
Zone substations	$24.42	$25.49
High Voltage Network	$16.07	$41.57
DSS and Low Voltage network	$54.15	$95.72

TABLE 7.14 LRMC - EXPORTS

VOLTAGE LEVEL	LRMC ($/KWH)
Low Voltage Network	$0.01

We have used the import LRMC is used as a check that that our indicative DUOS rates are more than LRMC, meaning these rates also include residual costs.

Conversion of $/kVA/year LRMC into c/kWh energy consumption charges involves:

- Multiplying by the estimated power factor to convert to $/kW/year
- Multiplying by the probability of maximum demand occurring in the energy time interval
- Dividing by the number of hours per year when the rate applies.

Conversion of $/kVA/year LRMC into demand charges involves:

- Multiplying by the estimated power factor if the demand charge is measured in kW
- Multiplying by the probability of maximum demand occurring in the demand time interval
- Multiplying by a diversity factor
- Dividing by the number of hours per year when the rate applies.

Table 7.15 shows LRMC converted to rates and compared with our indicative tariff rates. We have left off sub-transmission because sub-transmission investment is lumpy and therefore LRMC cannot be accurately calculated. All indicated rates are greater than LRMC.

TABLE 7.15 LRMC CONVERTED TO TARIFF RATES COMPARED WITH INDICATIVE TARIFF RATES

		Anytime	Peak	Demand	Demand
		c/kWh	c/kWh	$/kW	$/kVA
Connection voltage	LRMC	LRMC conversion to charging parameter			
LV residential	96	1	4		
LV small business	96	1	3	23	
LV medium business	96	0.5	3	23	
LV large business	96		1		30
HV	42		1		15
Connection voltage		Indicative 2026-27 DUOS rate			
LV residential		10	21		
LV small business		10	18	122	
LV medium business		5	18	122	
LV large business			2		155
HV			1		84

We have set the export charge rate for our CER tariff and flexible small tariff at LRMC and set the export credit for our CER tariff and flexible small tariff just below LRMC.

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