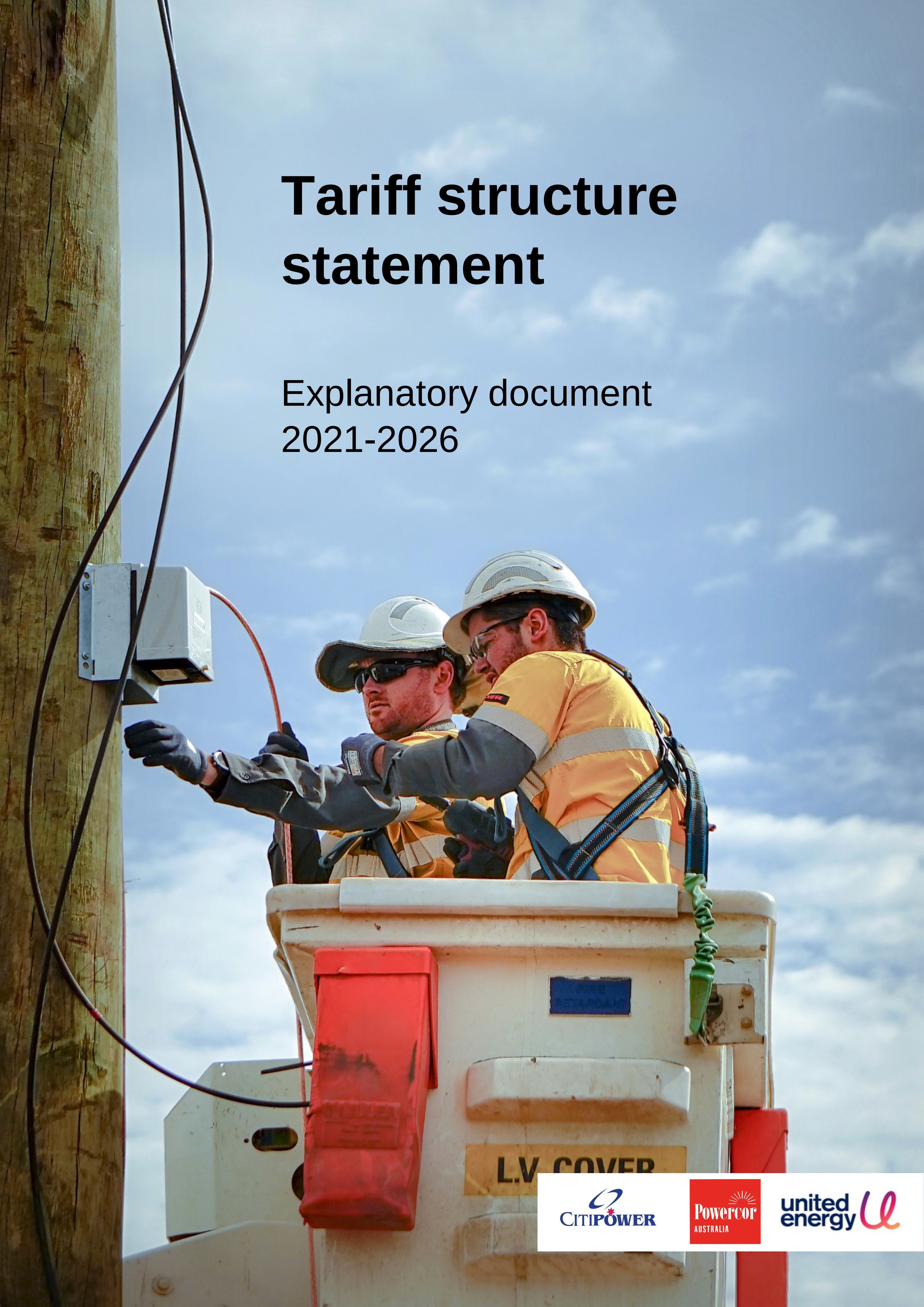
Tariff structure statement

Explanatory document
2021-2026



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1 Overview

1.1 Overview

CitiPower, Powercor and United Energy provide our customers with distribution network services, residential and small business metering, public lighting and other related services. For these services, we generally charge retailers, not customers. Ultimately, our customers pay for our services within their retail bill.

Before we set prices each year, we must determine how to structure our tariffs, and how we will assign customers to those tariff structures, which we set out in our Tariff Structure Statement (**TSS**). The next TSS will apply from 1 July 2021 to 30 June 2026.

This TSS Explanatory Document (**Explanatory Document**) provides the reasoning underlying our revised proposed TSS, including how we relied on the feedback we received from our stakeholders following the publication of our original proposed tariff structures in January 2020. It discusses CitiPower, Powercor and United Energy together since we propose to largely align tariff structures across all three networks.

The following table summarises our original proposed tariff structures and the changes we have made in our revised proposal.

Table 1 Original proposal and revised proposal

	Original proposal	Revised proposal
Residential	New connections, customers who upgrade to three-phase power supply, customers who install or upgrade solar PV and *flexible TOU* customers will be assigned to *new TOU* tariff	No change[1]
	Legacy TOU tariff customers consolidated onto a single *legacy TOU* tariff with a similar peak period to legacy tariffs	*Legacy TOU* tariff customers assigned to *new TOU* tariff
	New TOU tariff peak period 3pm to 9pm every day of year, with no seasonality	No change
	Peak/off-peak ratio 2.5	Peak/off-peak increased to 4.0
	Any customer can opt out of their tariff to the *single rate, new TOU* or *demand* tariff	No change
Small business	New connections, customers who upgrade to three-phase power supply and customers who install solar PV will be assigned to new TOU tariff	No change
	New TOU peak period will be 9am to 9pm workdays with peak/off-peak ratio of 4.5	No change
	Any customer can opt out of their tariff to the *single rate, new TOU* or *demand* tariff	No change

[1] The Victorian Government intends to mandate an assignment policy for electric vehicle chargers which may involve mandatory assignment to the new TOU tariff. Once this policy is known we will update our TSS.

	Original proposal	Revised proposal
Medium business	Default tariff is a *demand* tariff	No change
	Customers can opt out to an non-demand tariff	For United Energy customers can only opt out to a ToU tariff consistent with CitiPower and Powercor
Large business	Demand charge measure 8am to 8pm workdays instead of 24/7 and peak energy charge also based on 8am to 8pm workdays	Adopt an enhanced United Energy tariff structure across all three networks which comprises the following elements: 1. 12-month rolling demand charge measured 7am to 7pm workdays with a minimum level of chargeable demand 2. incentive demand charge with charge period determined based on location of customer 3. peak energy charge based on consumption from 7am to 7pm workdays 4. off-peak energy charge for consumption outside peak times For CitiPower and Powercor the default tariff will be a transition tariff, but customers can opt in to the full tariff
Tariff thresholds (CitiPower and Powercor)	60 MWh pa small/medium threshold 120 kVA or 160 MWh pa medium/large threshold	40 MWh pa small/medium threshold 120 kVA medium/large threshold
Tariff thresholds (United Energy)	40 MWh pa small/medium threshold 150 kVA or 400 MWh pa medium/large threshold	40 MWh pa small/medium threshold 120 kVA medium/large threshold

Note: TOU=time of use
Source: CitiPower, Powercor and United Energy

2 Background

2.1 What is the tariff structure statement?

A 'tariff' is how we charge a retailer for the services we provide to our customers. A tariff can be made up of different components such as fixed charges, energy usage charges or demand charges. These tariff components, the charging parameters, and the applicable prices constitute the tariff structure. The total network charges for any particular customer will depend on their assigned network tariff and their usage pattern.

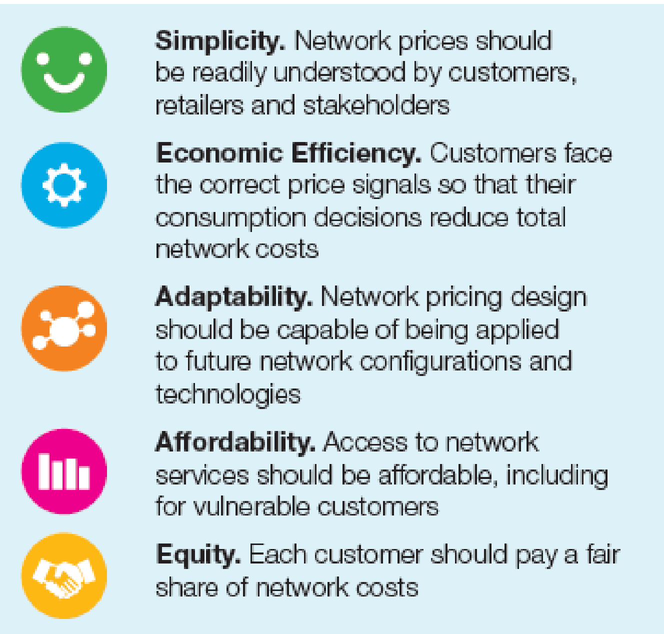
The TSS sets out each distributor's applicable tariffs and their policies and procedures for assigning or reassigning customers to particular tariffs. The TSS must ensure that the proposed tariffs conform with pricing principles specified in the National Electricity Rules (**the Rules**). The Rules also require that each distributor submit its TSS to the Australian Energy Regulator (**AER**) for approval alongside its Regulatory Proposal.

Our TSS explains our proposed tariff structures for the 2021–2026 period. It is published concurrently with this Explanatory Document, which provides information and analysis to support the revised TSS.

2.2 Pricing objectives

Our stakeholder engagement resulted in the identification of the following five objectives for tariff design.

Figure 1 The five stakeholder objectives for pricing design



It was recognised that no single tariff option could address all of these objectives, which means that we need to consider trade-offs or compromises between objectives.

These objectives continue to remain relevant considerations for our revised proposal.

2.3 Purpose of this Explanatory Document

This Explanatory Document does not repeat information provided in our original Explanatory Document but only covers the feedback we received on our original proposed TSS and how we responded in our revised TSS.

3 Responding to the draft determination

The following table summarises the issues and suggestions raised in the draft determination and how we have responded in our revised TSS.

Table 2 The draft determination and our response

Draft determination	Our response
The AER has requested that Victorian distributors offer their large business customers an alternative network tariff, in addition to their default tariffs, in the form of an individually calculated customer (**ICC**), or site-specific, tariff The AER has requested that Victorian distributors set out the parameters and processes they would use to develop the charging parameters and price levels of ICC tariffs	We propose to adopt an enhanced United Energy large customer pricing structure. The 'summer incentive charge' will be relabelled 'incentive demand charge' and the demand measurement window will be set based on location. For CitiPower and Powercor, the default will be that customers are put on a transition tariff but customers will have the choice to opt-in to the full tariff. Customers will not be able to opt out of the full tariff. The United Energy tariff also has a 12-month rolling demand charge which measures demand between 7am and 7pm local time, workdays. The United Energy tariff structure also has minimum demands and no fixed charges whereas the current CitiPower and Powercor tariffs have no minimum demands with fixed charges. Section 3.3 discusses this in more detail.
The AER asked us to consider closing the legacy tariffs and reassigning those customers to the new time of use and demand tariffs	We propose to re-assigned customers on *legacy TOU* tariffs to the *new TOU* tariff. Section 3.2 provides more detail.
The AER asked us to consider a larger peak to off peak ratio for their small customer cost reflective tariffs to more closely align with their historical values	We propose a peak/offpeak ratio of 4.0 for residential and 4.5 for non-residential to better align with legacy tariff ratios. This minimises bill impacts associated with *legacy TOU* tariff customers being moved to the *new TOU* tariff. It also lowers our off-peak rate which applies during solar export times and therefore resembles a solar sponge.
The AER asked CitiPower to consider amending peak charging windows for business customers (opt-in medium business 7am to 11pm)	The peak charging window for medium business customers is now proposed to be 10am to 6pm.
The AER questioned United Energy allowing medium business customers to opt out to a single rate tariff	United Energy will only allow business customers consuming less than 40 MWh pa to opt in to the single rate tariff, consistent with CitiPower and Powercor. Unite Energy medium business customer will only be able to opt out to the *new TOU* tariff United Energy will transfer existing business customers consuming more than 40 MWh pa on the *single rate* tariff to *new TOU* tariff

The AER requested CitiPower and Powercor clarify the default medium business tariff, as there is inconsistency in the claimed tariff and provided charges	The default medium business tariff has a flat energy rate. The confusing peak/off-peak rates are now shown as a single anytime rate.

Draft determination	Our response
The AER requested analysis from Powercor to support its charging windows for its business customers.	Powercor will probably adopt three different pricing windows based on location for its large customers. Further analysis is provided in section 3.3.
The AER expressed concern that the inconsistency in annual consumption bands across the Victorian distributors may be difficult for customers to understand	We are proposing to align consumption bands across our three networks and make these bands clear in our TSS
The AER indicated they were still engaging on our proposed approach to grid-scale batteries	We propose to retain the existing proposal, except our revised TSS now also proposes that a network charge can only be waived if any applicable avoided TUOS rebate is also waived.
The AER requested we provide more information on: • how tariff proposals are integrated with demand management and other initiatives • how we intend to manage increasing volumes of solar PV, customer batteries, and EVs through use of tariffs and tariff trials • our intentions and strategy on tariff trails The AER also encouraged us to continue to monitor solar sponge for further consideration	See section 3.1
The AER expressed that trial tariffs during 2021–22 will need to be detailed in their revised TSSs. This applies to new trials, as well as continuation of existing trials	See section 3.1.6 and the revised TSS

Source: CitiPower, Powercor and United Energy

3.1 How our tariff structures align with our overall expenditure program

Throughout our engagement and preparation of our regulatory proposals, we have heard that stakeholders are interested to better understand how our tariff structures link with our expenditure programs. This is particularly so for programs that will lead to deferred augmentation expenditure, including management of distributed energy resources (DER) and demand management.

The draft determination stated the TSS should set out our broader strategy to pricing that will govern our operations over the regulatory period and beyond. This includes how we intend to manage increasing DER, including solar PV, batteries and electric vehicles (EV), and how we plan to refine and apply this strategy over the next regulatory period, such as through trials under the sub-threshold tariff clause. The AER has also asked us to explicitly integrate our approach to tariffs design and demand management.

3.1.1 Our tariff structures indicate a relatively slow transition to behavioural change

Our proposed tariff structures are a product of years of consultation with stakeholders. The proposed structures are designed to balance the often-competing objectives of simplicity, economic efficiency and equity. This has resulted in a relatively slow-paced transition to cost-reflective tariffs.

Following feedback on our initially proposed TSS, we are now proposing some additional steps to increase the pace of transition. Nevertheless, there is still a long way to establish the level of cost-reflectivity that exists in the wholesale electricity market.

3.1.2 Integration of DER through our Future Network program

Our Future Network program is an updated and streamlined combination of initiatives that were formally under our Solar Enablement and Digital Network proposals. The Future Network program is designed to ensure the most efficient and optimal integration of DER and demand response/management on our network during 2021–2026. (For more details on the program refer to the Executive Summary.)

In preparing our revised TSS, and in finalising our Future Network program, we have assumed that most *new* DER customers will be on a time-of-use tariff from July 2021. Today this comprises mainly solar PV and battery customers, but will grow to include EV customers from 2025 onwards. However, as the time-of-use tariffs are designed to address several competing challenges on the network, we cannot rely on these tariffs alone to lead to an efficient integration of DER. Our stakeholders have told us the same—that our current planned transition to cost reflective tariffs is likely to be too slow to modify significant behavioural change.

As such, our revised TSS and Future Networks program are complementary aimed at ensuring customers have access to the grid to maximise on their investment in DER whilst at the same encouraging them to do so at times where capacity is available on the network. The figure below, presented to our Customer Advisory Panel (CAP), summarises how our tariff structures fit into our overall Future Network program.

The our proposed TSS and Future Network program together are expected to at least halve the augmentation on our network that would otherwise occur over the next regulatory period.

Figure 2 How our tariff structure statement fits into our Future Network program

Initiative

- **Making export capable connections and enabling our customers to connect a 5kW system with export capability**
- **Removing solar constraint that would otherwise occur for majority of customers**
- **Enabling more dynamic LV network management through operating envelopes**
- **Enabling dynamic demand response and demand management programs on the network**

Tariff assumption

Tariffs

- New DER customers are put on time-of-use tariffs when connecting
- The time of use tariff is expected to shift some usage to a period before 3pm and after 9pm
- It may also encourage more self-consumption for solar electricity during 3pm and 9pm
- **Exports**: in our forecasts we assume that solar exports will be mostly between 11am and 3pm—with dynamic voltage management this will be higher than without it
- **EVs**: We also assume that new EVs will be charging mostly at night as a result of our initiatives and the tariff
- **Most existing customers**: without DER and remain on the flat tariff until 2026

Priorities expenditure

Operating expenditure

- To accommodate growing exports, there will be a significant increase in tapping of transformers and compliance obligations, which we are proposing as an operating expenditure step change
- This is the most efficient solution for enabling solar exports where possible, and is an efficient trade off operating and capital expenditure
- There will also be an increase in demand response and demand payments. We have only forecast for known cost increases, acknowledging they are likely to be higher by 2026

ICT investment

- Investment in DVMS and LV DERMS
- Investment in IT systems that allow for LV network analytics of AMI data and managing local constraints to determine opportunities for demand response

Network expenditure

Network augmentation

- There will still be need for augmentation of distribution transformers, however with tapping and IT solutions we have reduced the need for augmentation by **at least half**

Network replacement

- Through better management of exports and demand, it is likely some replacement expenditure will be deferred, albeit at immaterial levels compared to upgrades and augmentation

Source: CitiPower, Powercor and United Energy

3.1.3 Integration of tariffs and demand management

We agree with the draft determination that cost-reflective tariffs can potentially achieve a similar objective and results to targeted demand management programs. As such, it is important that we consider any overlaps between proposed tariffs and existing or future demand management programs.

We can confirm our existing demand management programs across our two networks, namely United Energy's Summer Saver program and Powercor's Energy Partner program, both include direct payments for reductions in usage. They do not involve network tariffs. These geographically targeted "carrot" programs fill a gap that cannot yet be filled by locational network tariffs "stick", which are still not acceptable to the community.

United Energy's battery trial with the Australian Renewable Energy Agency (ARENA), which involves the installation of over 40 pole-mounted battery energy storage systems across the low voltage network is another initiative we are undertaking to manage demand. Amongst a number of benefits being trialled, we expect the program will benefit our consumers through deferring augmentation.

We expect that as our Future Network initiatives are progressed, and opportunities for DER participation and more dynamic demand response become available, our tariff offerings will evolve (beyond the 2021–2026 regulatory period). However, it is too early to speculate what those tariffs may look like. At this stage it is more appropriate to continue to explore options through tariff trials.

3.1.4 Electric vehicles

The Victorian Government is in the process of developing a policy on tariff assignment for small customers with an EV charger. To avoid any inconsistencies between our TSS and the currently unknown Victorian Government policy, we have not specified tariff assignment criteria relating to EVs. Our TSS will be updated to reflect the policies of the Victorian Government once they are known.

We recognise the importance of managing the load shape of EV charging to avoid significant new augmentation investment. EV uptake is still low and not expected to rapidly escalate in the next few years. There is also uncertainty as to future EV charging practice such as whether it will mostly be at home, whether fast chargers will be used in the home, and the capabilities of technology to manage charging. This is an ideal time for EV tariff and demand management trials and we intend to undertake such trials.

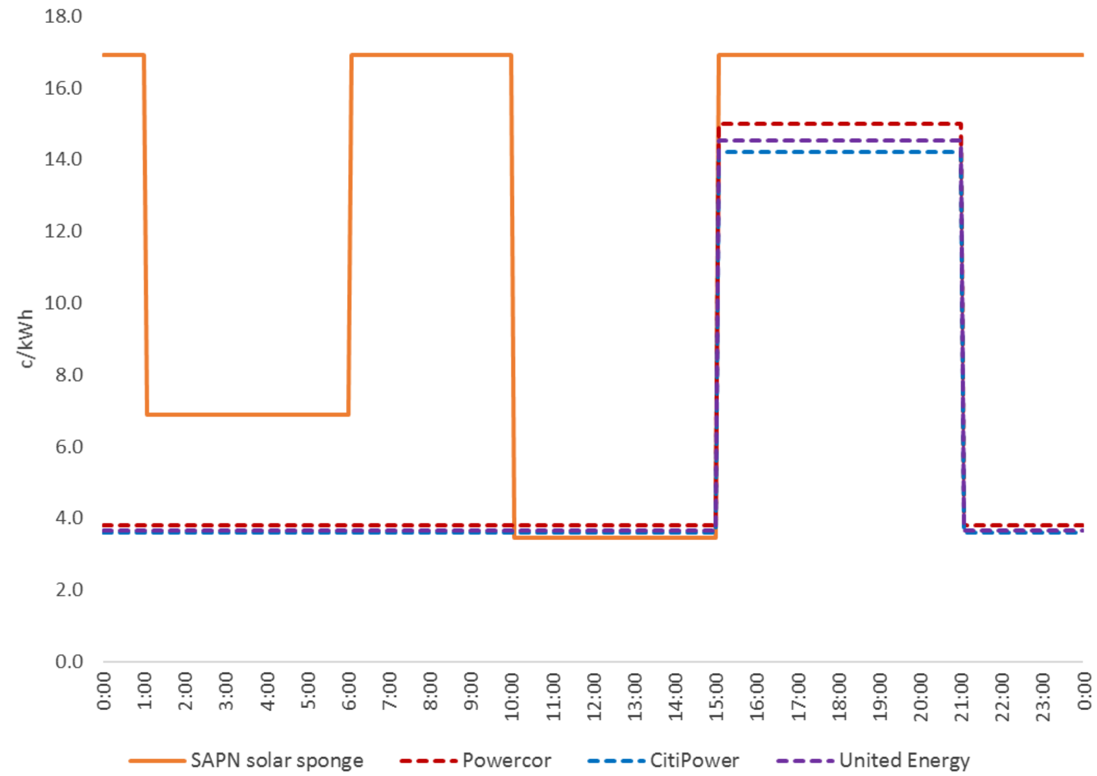
3.1.5 Solar sponge

Some stakeholders suggested that we consider adding a solar sponge rate to our new residential TOU tariff.

A solar sponge is a low rate that applies from around midday, for example, SA Power Network's (**SAPN**) solar sponge is from 10am to 3pm. Figure 3 compares the SAPN solar sponge tariff for 2020-21 to the proposed two part tariffs of CitiPower, Powercor and United Energy for 2021-22. It demonstrates that SAPN's solar sponge rate, and our off-peak rate are very similar over 10am to 3pm and therefore provide similar incentives. Additionally, our low off-peak rate does not provide much scope to carve out a further lower solar sponge rate. It also demonstrates the simplicity of our proposed two-part ToU tariff compared with the SAPN tariff. For these reasons, an additional solar sponge rate does not appear necessary at this stage.

We intend to continue to monitor the situation consistent with the AER's recommendation in its draft decision.

Figure 3 Comparison of SAPN's solar sponge tariff with our proposed new ToU tariffs



Source: CitiPower, Powercor and United Energy

3.1.6 Tariff trials

Like our stakeholders, we are cognisant of the importance of tariffs in facilitating energy market transition. We will undertake a number of tariff trials over the next regulatory period to inform our next TSS. This approach was discussed and supported by our Customer Advisory Panel. It reflects a prudent and efficient approach to managing future challenges and change which is critical for maintaining community support for tariff reform.

Tariff trials we are presently considering include domestic EV tariffs, apartment block public EV tariffs, large EV public charging infrastructure tariffs, community energy tariffs, grid battery tariffs and more cost-reflective large customer tariffs.

Tariff trials can only commence in the first year of a regulatory period if they are identified in the TSS. The following tariff trials are planned to commence in the first year of this regulatory period:

- dynamic domestic EV tariff—we are currently in discussions with retailers about commencing a trial of a dynamic EV tariff where the half-hour pricing profile for each day is nominated a day in advance.
- the Newstead community in the Powercor distribution area intend to shortly appoint a service provider to assist them achieve their goal of 100 per cent renewable energy. We have committed to negotiate and trial a tariff once the service provider is appointed.
- the United Energy / ARENA battery trial plans to install 40 LV grid batteries to manage network demand. Our TSS proposes that the network tariff is waived for grid batteries that will be operated to the net benefit of the network, or that are owned by the distributor. In the event that the AER rejects this proposal, we intend to trial the waiving of the network tariff.

3.2 Residential legacy TOU customers

The AER in its draft decision suggested that the distributors consider closing the residential legacy tariffs and reassigning those customers to the new time of use and demand tariffs. The AER considered that leaving customers on their legacy tariffs may not be consistent with progressing network tariff reform and may also represent a missed opportunity.

The Victorian distributors proposed to retain the legacy tariffs because some stakeholders were concerned about the potential customer impact of reassignment. The AER's draft decision points out that these concerns are mitigated by:

- customers being able to choose the retail tariff structure that best suits their needs and preferences;
- the Victorian government having a number of complementary measures to ensure customers are in control of their retail offer and to support vulnerable customers; and
- the Victorian Default Offer (VDO) providing all customers in Victoria with the option of a regulated standing offer, which may assist to inform their decisions. All customers have the ability to request their retailer to assign them to the VDO offer.

AGL also proposed that the legacy TOU tariff residential customers be reassigned to the new TOU tariff.

The AER subsequently asked the Victorian distributors to provide a network bill impact analysis for this reassignment, comparing 2020 network bills with 2021/22 network bills. The main findings were that:

- 96% of Victorian legacy tariff customers will be better off
- 95% of CitiPower legacy tariff customers will be better off
- 93% of Powercor legacy tariff customers will be better off
- 95% of United Energy legacy tariff customers will be better off.

The impact analysis is shown for all Victoria, CitiPower, Powercor and United Energy in the next few pages.

The AER convened a meeting with the Victorian distributors, Department of Environment, Land, Water and Planning and Energy Consumers Australia to discuss the impact analysis. No objections were raised in respect of reassigning legacy tariff customers to the new ToU tariff.

Our revised TSSs therefore propose to reassign legacy tariff customers to the new ToU tariff.

3.2.1 Combined bill impact for Victorian residential customers moving from existing legacy time of use 2020 tariffs to the indicative 2021/22 new time of use tariff (~399,275 customers)

Table 3 Bill impacts – all Victoria

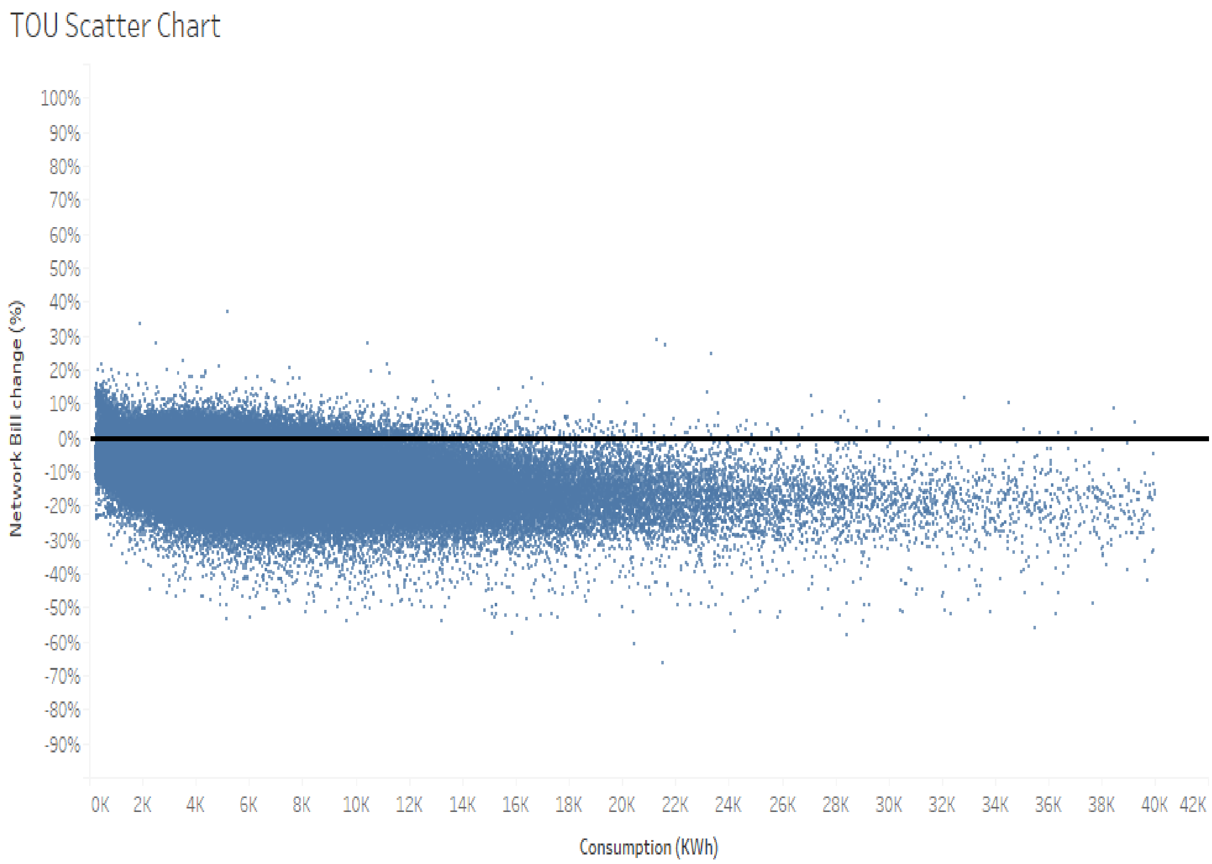
Bill Impact $ Table

Bill impact threshold	No of customers	
	Better Off	Worse Off
<$10	24,233	10,137
>$10-$20	38,648	3,759
>$21-$50	119,453	2,350
>$51-$100	105,599	410
>$100	94,666	60
Grand Total	382,599	16,716

Bill Impact % Table

Bill impact threshold %	No of customers	
	Better Off	Worse Off
<5%	67,788	14,555
>5%-10%	127,219	1,797
>11%-20%	163,400	350
>20%	24,192	14
Grand Total	382,599	16,716

Figure 4 Bill impact scatter chart – all Victoria



Consumption vs. Bill change %. The data is filtered on Distributor, which keeps AusNet, CitiPower, Jemena, Powercor and United.

3.2.2 Bill impact of CitiPower residential customers moving from existing 2020 legacy time of use tariffs to the indicative 2021/22 new time of use tariff (~41,247 customers)

Table 4 Bill impacts - CitiPower

Bill Impact $ Table

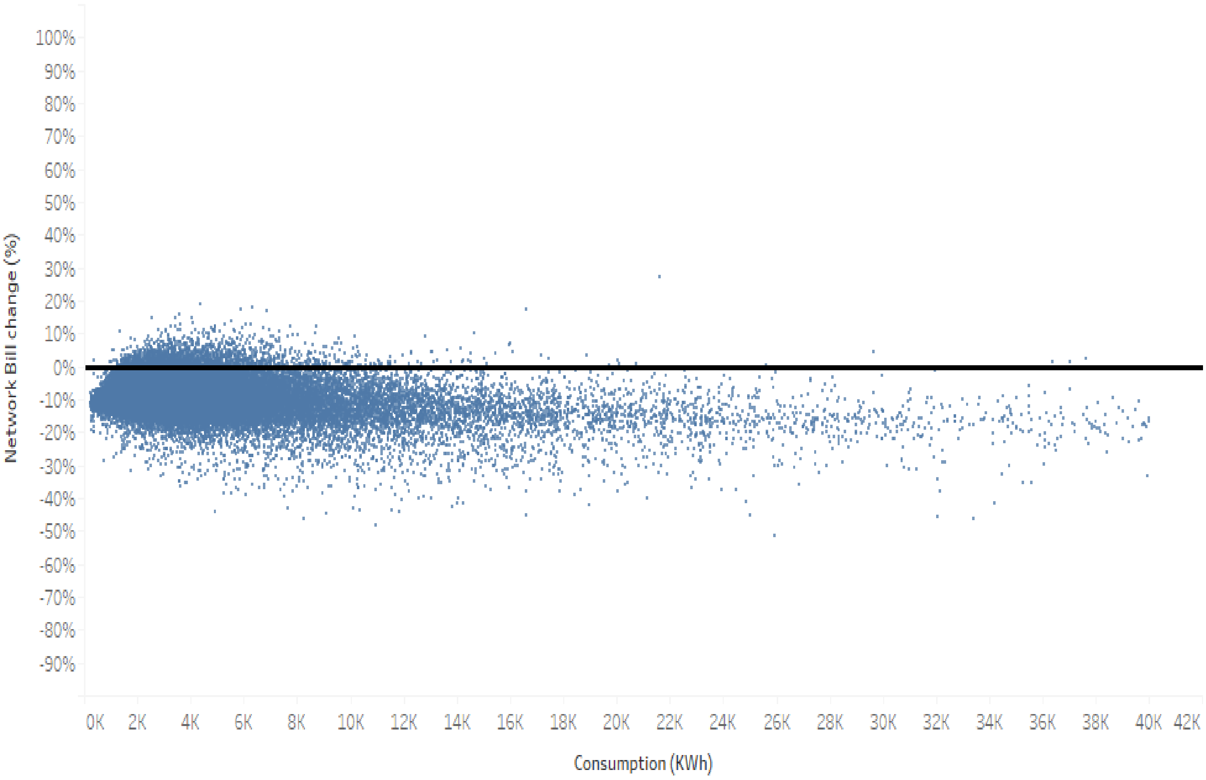
Bill impact threshold	No of customers	
	Better Off	Worse Off
<$10	2,390	1,035
>$10-$20	5,464	446
>$21-$50	17,044	369
>$51-$100	8,763	72
>$100	5,656	8
Grand Total	39,317	1,930

Bill Impact % Table

Bill impact threshold %	No of customers	
	Better Off	Worse Off
<5%	6,738	1,616
>5%-10%	14,726	262
>11%-20%	16,331	51
>20%	1,522	1
Grand Total	39,317	1,930

Figure 5 Bill impact scatter chart - CitiPower

TOU Scatter Chart



Consumption vs. Bill change %. The data is filtered on Distributor, which keeps CitiPower.

3.2.3 Bill impact of Powercor residential customers moving from existing 2020 legacy time of use tariffs to the indicative 2021/22 new time of use tariff (~145,543 customers)

Table 5 Bill impacts - Powercor

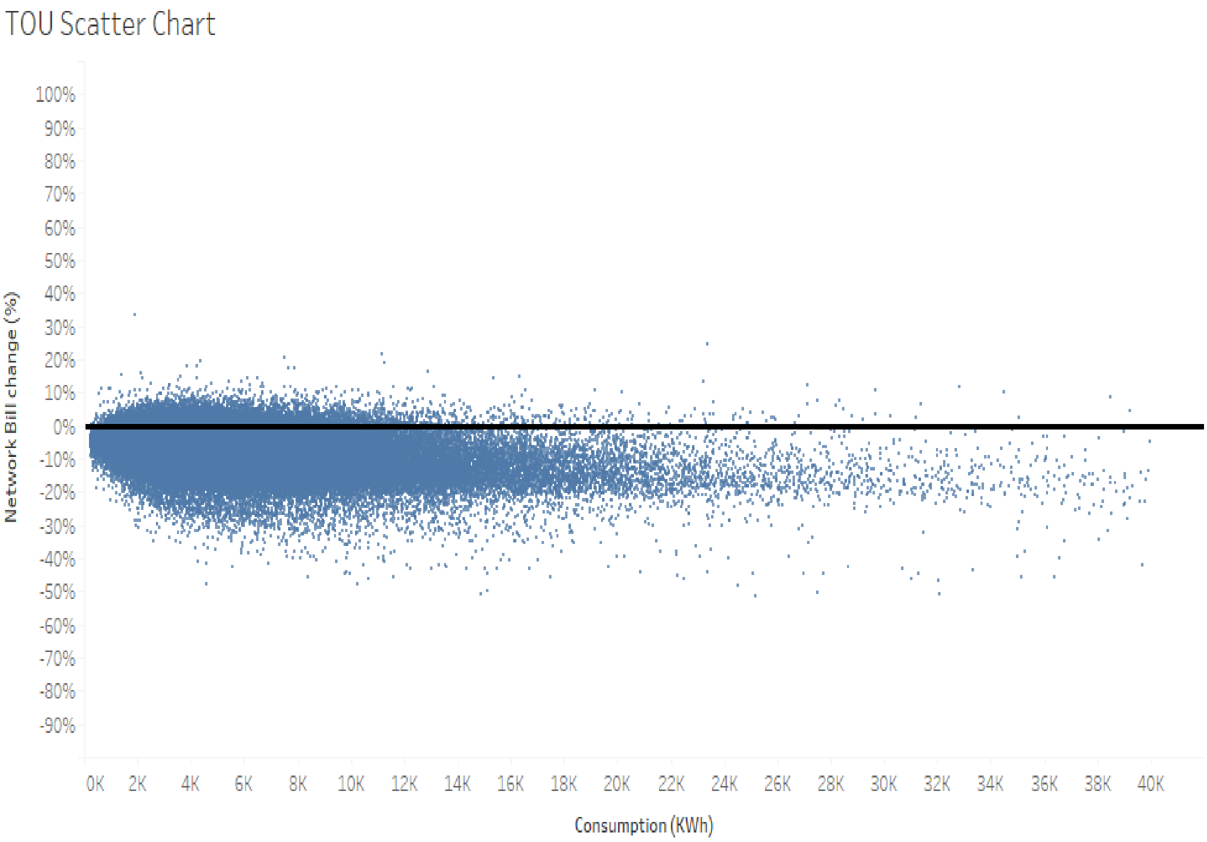
Bill Impact $ Table

Bill impact threshold	No of customers	
	Better Off	Worse Off
<$10	12,562	5,421
>$10-$20	17,062	2,260
>$21-$50	43,852	1,614
>$51-$100	37,742	280
>$100	24,708	42
Grand Total	135,926	9,617

Bill Impact % Table

Bill impact threshold %	No of customers	
	Better Off	Worse Off
<5%	35,499	8,726
>5%-10%	48,609	801
>11%-20%	48,541	86
>20%	3,277	4
Grand Total	135,926	9,617

Figure 6 Bill impact scatter chart - Powercor



Consumption vs. Bill change %. The data is filtered on Distributor, which keeps Powercor.

3.2.4 Bill impact of United Energy residential customers moving from existing 2020 legacy time of use tariffs to the indicative 2021/22 new time of use tariff (~49,784 customers)

Table 6 Bill impacts – United Energy

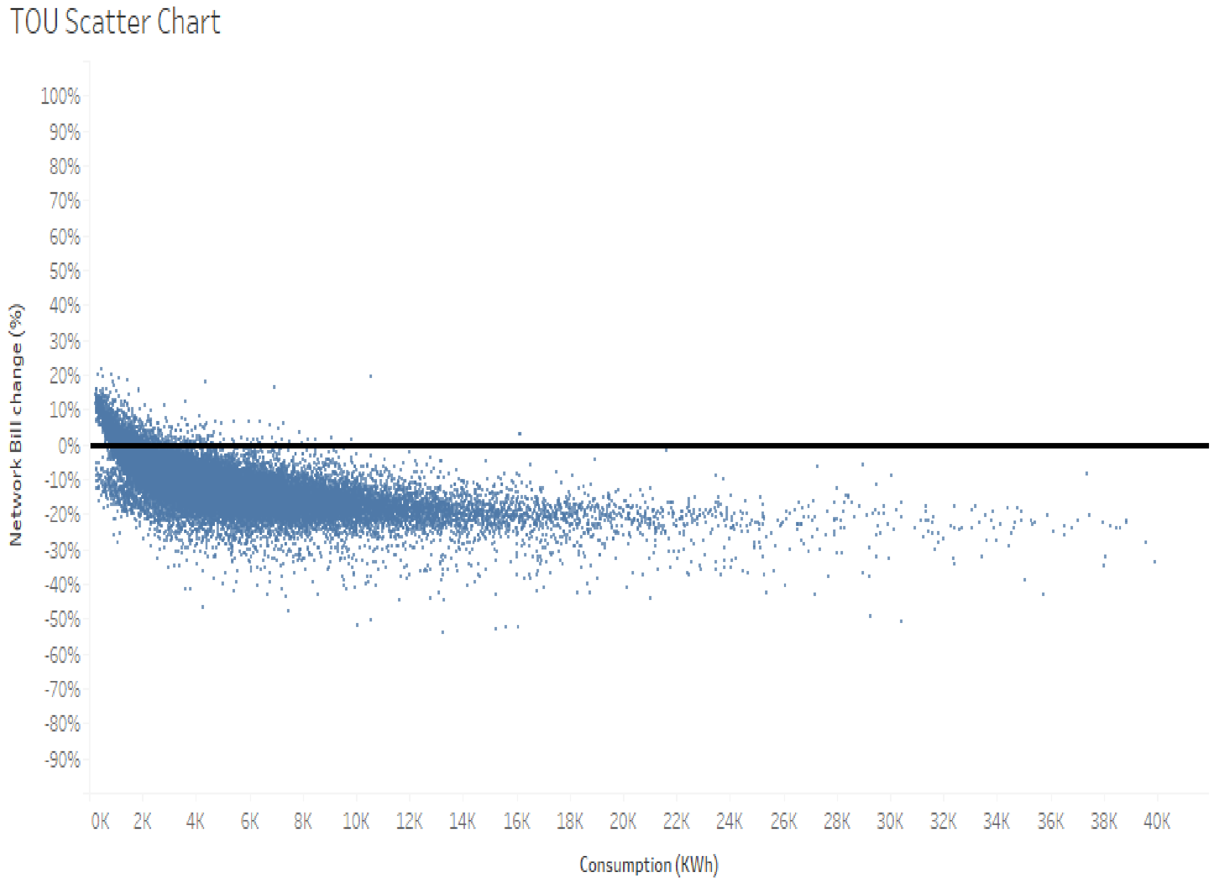
Bill Impact $ Table

Bill impact threshold	No of customers	
	Better Off	Worse Off
<$10	3,410	1,767
>$10-$20	4,814	528
>$21-$50	14,985	57
>$51-$100	13,798	3
>$100	10,422	
Grand Total	47,429	2,355

Bill Impact % Table

Bill impact threshold %	No of customers	
	Better Off	Worse Off
<5%	5,714	1,673
>5%-10%	13,509	509
>11%-20%	24,780	171
>20%	3,426	2
Grand Total	47,429	2,355

Figure 7 Bill impact scatter chart – United Energy



Consumption vs. Bill change %. The data is filtered on Distributor, which keeps United.

3.3 Large business

The AER draft decision requested that Victorian distributors offer their large business customers an alternative network tariff, in addition to their default tariffs, in the form of an ICC, or site-specific, tariff.

The AER has requested that Victorian distributors set out the parameters and processes they would use to develop the charging parameters and price levels of ICC tariffs.

The AER also urged us to consider more cost-reflective tariffs with locational signals.

We were not expecting this requirement to be included in the draft decision and consider that there is insufficient time in the nine-week revised proposal period to design and develop a completely new tariff. However, we are proposing to enhance the United Energy large customer tariff structure to make it more cost-reflective and apply it across CitiPower, Powercor and United Energy.

United Energy already has a large customer network tariff that is reasonably cost-reflective. In addition to a 12-month rolling peak demand charge, it applies a further 'summer incentive' demand charge in summer months only based on monthly maximum demand from 3pm to 6pm workdays. We are now proposing to re-label the 'summer incentive' charge to 'incentive demand' charge and the months and times when demand is measured for this charge will be location dependent.

The following table compares the current CitiPower and Powercor tariff structure with the current and enhanced United Energy tariff structures.

Table 7 Comparison of large customer tariff structures

	CitiPower & Powercor current	United Energy current	United Energy enhanced
Fixed charge	Yes	-	-
12-month rolling demand charge	Measured 24/7	Measured 7am to 7pm workdays	Measured 7am to 7pm workdays
Minimum chargeable demand for 12-month rolling demand	-	150 kVA for low voltage 1,150 kVA for high voltage 11,100 kVA for sub-transmission	120 kVA for low voltage 1 MVA for high voltage 10 MVA for sub-transmission
Incentive demand charge	-	Measured 3pm to 6pm workdays in summer months	Location dependent
Peak energy charge	7am to 11pm weekdays	7am to 7pm workdays	7am to 7pm workdays
Off-peak energy charge	Non peak times	Non peak times	Non peak times

Source: CitiPower, Powercor and United Energy

3.3.1 Incentive demand charge

Whilst the current 3pm to 6pm summer incentive demand charge made sense for most of the United Energy distribution network, this is now not fit-for-purpose across CitiPower, Powercor and United Energy because:

- distribution assets which largely supply residential load, typically peak in the 4pm to 7pm local time period in summer
- some distribution assets which largely supply commercial and industrial load, typically peak in the 12pm to 3pm local time period in summer
- some areas of Powercor which are colder and don't have gas, typically peak in the 7am to 10am period in winter.

The following charts present preliminary analysis of zone substation peak demand times over recent years to get a better sense of the distribution of peak times across zone substations. The zone substations have been grouped in high, medium and low utilisation. Some judgement has been applied as some zone substations peak at different times and seasons depending on the weather, load transfers and time switches.

Figure 8 CitiPower zone substation peak times

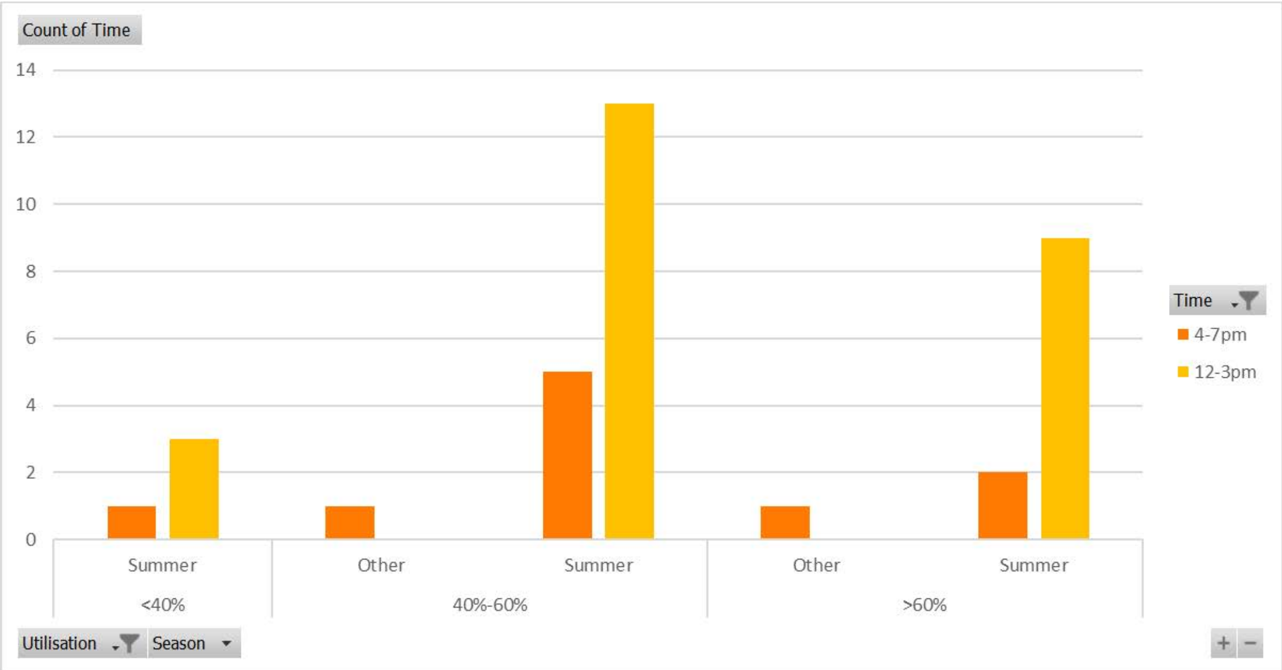


Figure 9 Powercor zone substation peak times

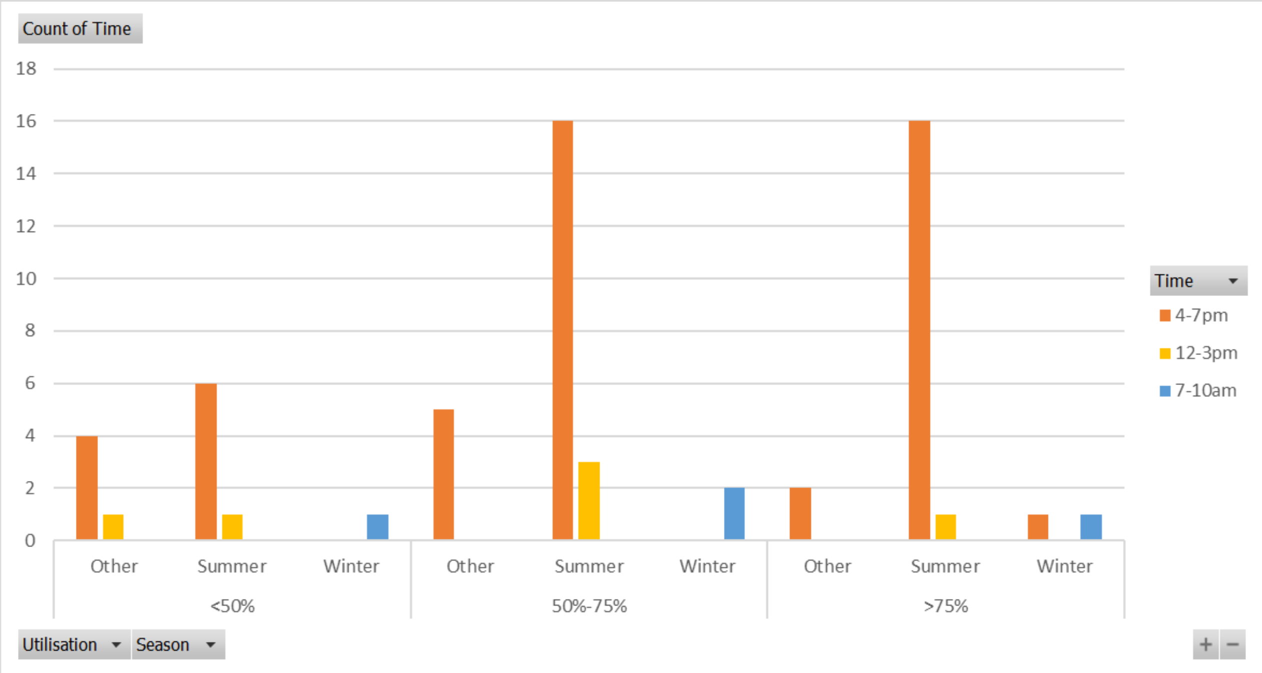
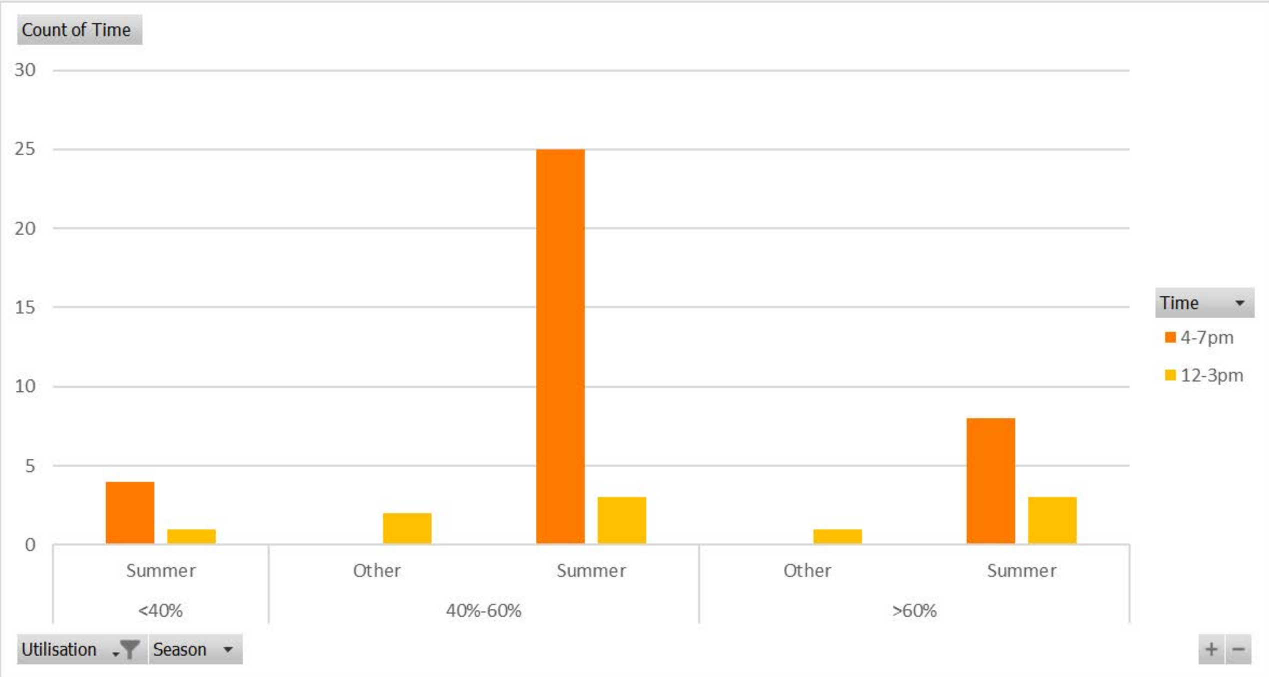


Figure 10 United Energy zone substation peak times



Based on the above preliminary analysis customers could potentially be assigned to the following incentive demand measurement periods based on the zone substations that they are supplied from:

- 4-7pm workdays from December to March
- 12-3pm workdays from December to March
- 7-10am workdays from May to August.

A material part of the network charges for sub-transmission and high voltage customers is derived from transmission charges. We are charged for transmission services based on demand charge which varies in magnitude by terminal station and an anytime energy charge. The demand charge is based the ten weekdays when power system demand was highest, between 1100 hrs and 1900 hrs in the local time zone from 1 March to 28 February.

The following table shows the dates and times of the ten highest weekdays over the last three years. Transmission demand charges are predominantly based on demand from 3-6pm in summer, driven by a combination of residential (typically 4-7pm) and commercial and industrial (typically 12-3pm) peak demand.

Table 8 Dates and times on which transmission demand charges have been based

2019-20	2018-19	2017-18
31-Jan-2020 17:00	24-Jan-2019 18:00	19-Jan-2018 15:30
30-Jan-2020 18:00	25-Jan-2019 11:30	07-Feb-2018 16:30
01-Mar-2019 17:00	28-Feb-2019 17:00	18-Jan-2018 18:00
20-Dec-2019 18:00	07-Dec-2018 15:30	29-Jan-2018 13:30
18-Dec-2019 17:00	30-Jan-2019 15:30	29-Nov-2017 17:00
30-Dec-2019 15:00	14-Jan-2019 17:00	30-Nov-2017 15:30
15-Jan-2020 15:00	06-Feb-2019 16:30	13-Dec-2017 17:00
20-Jun-2019 18:30	15-Jan-2019 16:00	19-Dec-2017 15:30
09-Dec-2019 17:00	04-Jan-2019 15:00	15-Mar-2017 17:00
14-Jan-2020 18:00	22-Jan-2019 17:00	11-Jan-2018 17:00

Source: CitiPower, Powercor and United Energy

The period over which transmission demand charges are based will also be taken into account when assigning large customers to an incentive demand period.

Further analysis is required before we can finalise the incentive demand periods and the assignment of individual customers to those periods.

3.3.2 Transition arrangements

For United Energy customers, these changes will be relatively small. For most customers, the incentive demand period will shift forward by one hour from 3-6pm to 4-7pm. A relatively small proportion will have the incentive demand period reset from 3-6pm to 12-3pm.

For CitiPower and Powercor customers, the change in tariff structure is material. Every tariff component of their network charge will change and the incentive demand charge is something that they may not be familiar with.

We therefore propose a transition for CitiPower and Powercor as follows:

- In 2021/22 all large business customers will be assigned to a transition tariff which will have all the tariff components of the full tariff, but the incentive demand charge will be set to zero. This means customers will be able to see their incentive demand on their bill in the first year, but without being charged for it.
- In 2022/23 the incentive demand charge will be set to 33% of the full tariff level and the 12-month rolling demand charge will correspondingly reduce.
- In 2023/24 the incentive demand charge will be set to 67% of the full tariff level and the 12-month rolling demand charge will correspondingly reduce.
- In 2024/25 the incentive demand charge will be set to 100% of the full tariff level and the 12-month rolling demand charge will correspondingly reduce.
- The minimum demand for the 12-month rolling demand charge will be introduced at lower levels in 2021/22 and then increased to the full level by 2024/25 , otherwise the combination of the full minimum demand and the higher transitional rolling demand charge in the transition years will punish customers with low demand.
- On 1 July 2021 we will also introduce the full tariff. Any large business customer can opt into the full tariff from the start of the next month. To avoid opportunistic tariff switching, once a customer has moved to the full tariff they won't be allowed to revert back to the transition tariff.

We will consult with retailers on a communication plan for large customers and the business-to-business implementation plan. We anticipate that in the first quarter of 2021 we will write to each CitiPower, Powercor and United Energy large customer notifying them of these changes.

3.3.3 Tariff assignment criteria

It makes sense that if we align large customer tariffs across the three networks, we should also align the tariff assignment criteria for large customers.

The HV and sub-transmission assignment criterion is simply supply voltage.

The following table shows the current assignment criteria for large low voltage tariffs for four of the five Victorian distributors. AusNet has been left out because tariff assignment appears more complex.

Table 9 Current demand and energy thresholds for low voltage large customers

	CitiPower	Powercor	United Energy	Jemena
Demand	>120 kVA	>120 kVA	>150 kVA	>120 kVA
Energy	>160 MWh pa	>160 MWh pa	>400 MWh pa	>400 MWh pa

Source: CitiPower, Powercor and United Energy

The most common demand criterion is 120 kVA which would result in the least number of customers being affected by alignment. We therefore we propose 120 kVA to be the demand criterion.

We see no reason to retain an energy threshold since it is maximum demand that drives network investment.

We note any customer consuming less than 160 MWh pa can opt out of a demand charge. This is currently mandated by the Victorian Government and we plan to retain this safety net.

3.3.4 Network bill impacts

The charts below present the bill impacts across CitiPower and Powercor large customers of changing from their current tariff structure to the proposed tariff structure – both full and transitional.

We used meter data over the period 1 July 2019 to 30 June 2020, and excluded any customer which did not have a full year of meter data.

We compare network bill using the first half of 2021 prices and 2021/22 prices which are revenue neutral.

We believe these customer impacts are an acceptable compromise with improved cost reflectivity.

Figure 11 CitiPower network bill impact – transitional tariff

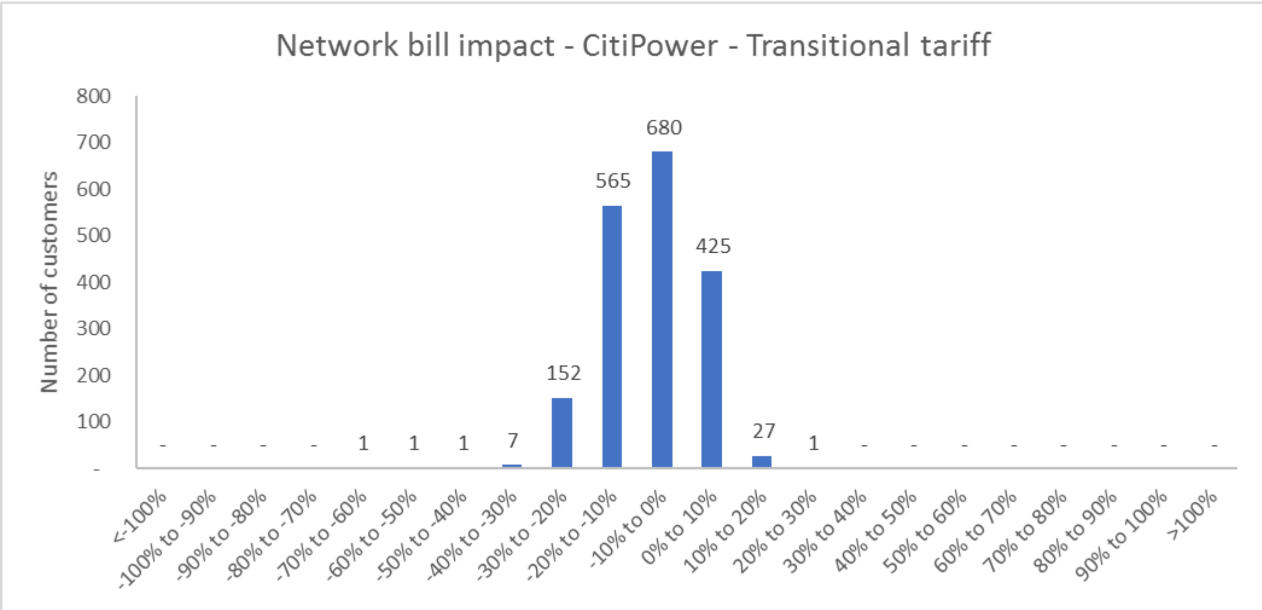


Figure 12 CitiPower network bill impact – full tariff

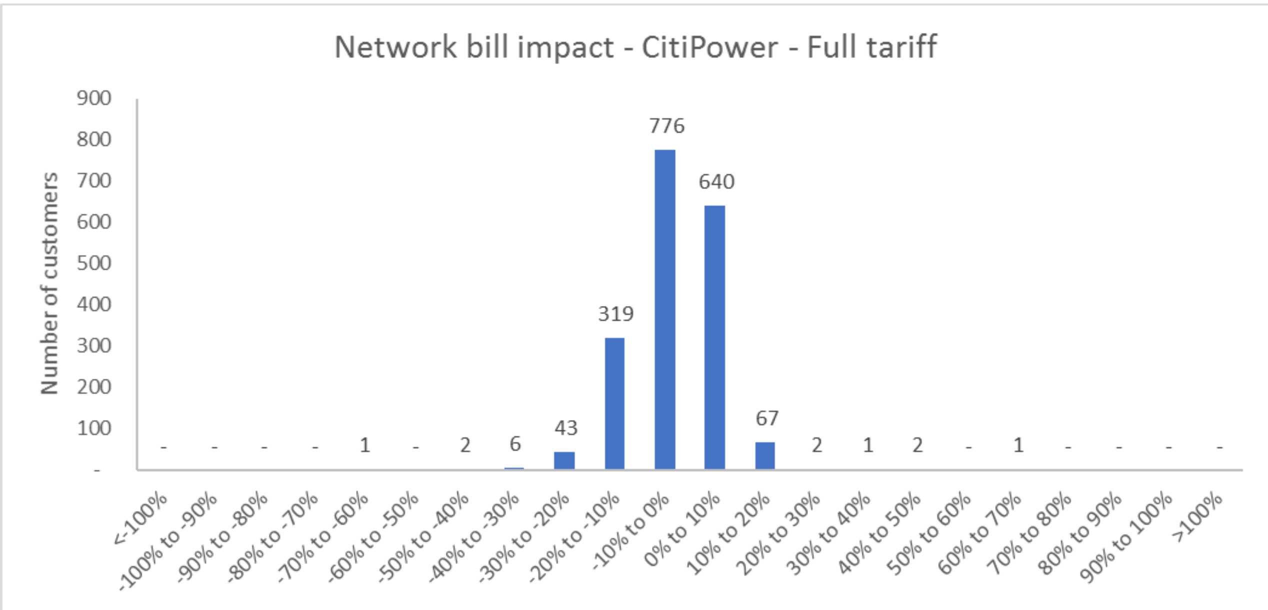


Figure 13 Powercor network bill impact – transitional tariff

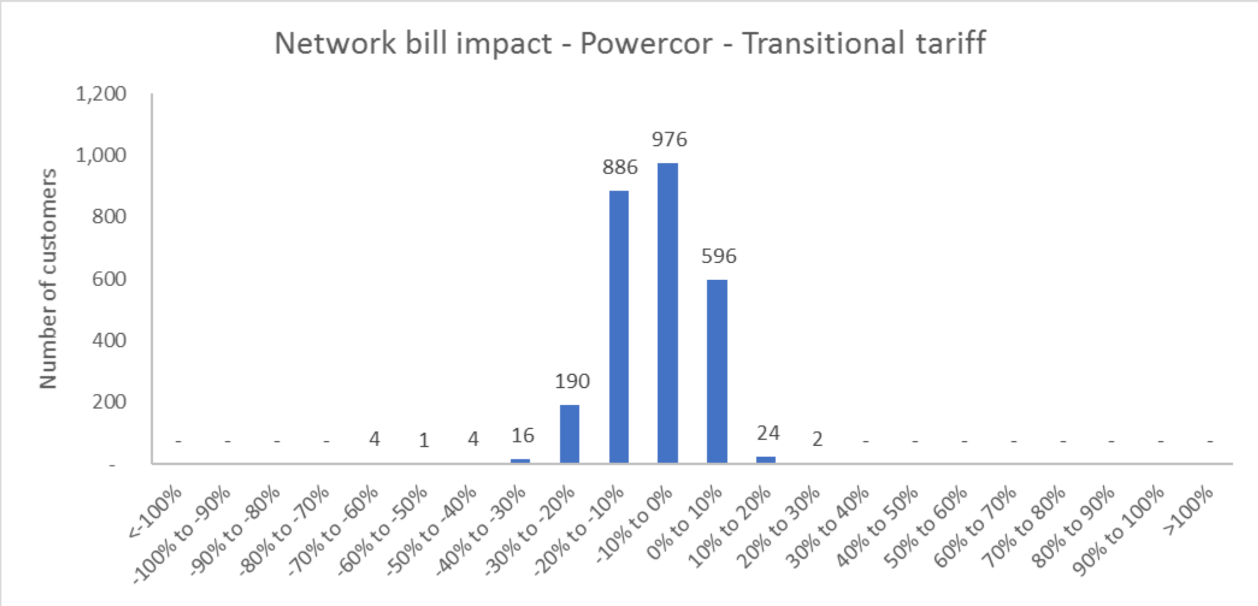
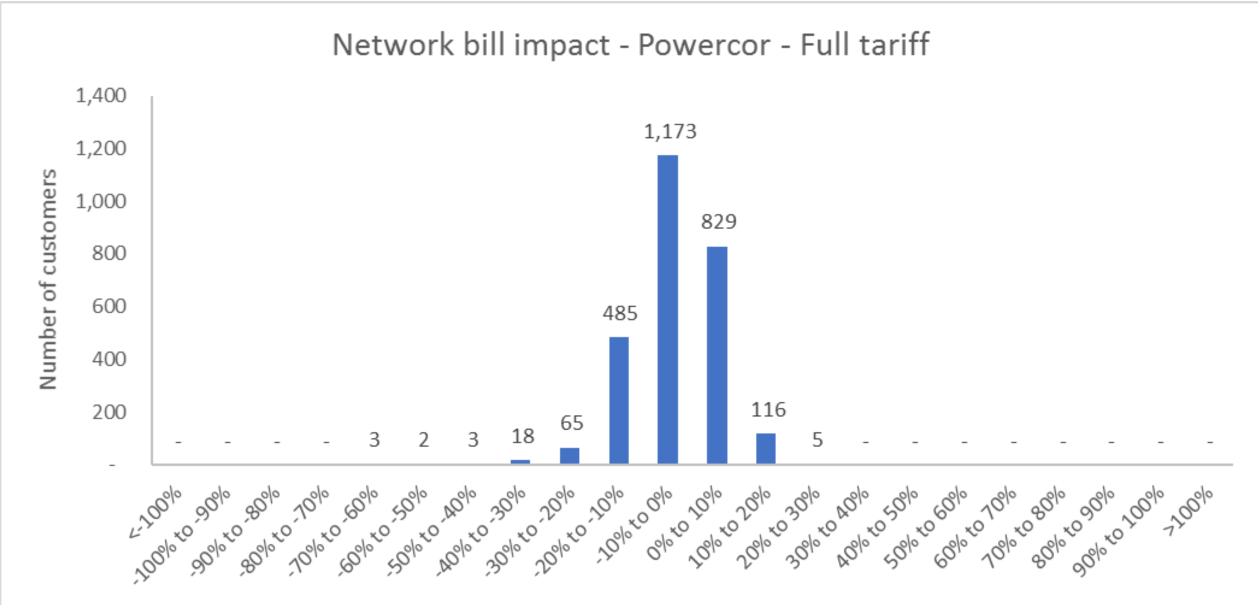


Figure 14 Powercor network bill impact – full tariff



4 Responding to stakeholder feedback

Our TSSs for our regulatory proposals was developed through an extensive stakeholder engagement and collaboration with other Victorian distributors. Since submitting our proposal in January 2020, we have received further feedback, through written submission to the AER's issues paper and bilateral meetings and through our newly established Customer Advisory Panel (CAP).

The following table summarises issues raised in stakeholder feedback on our proposed TSS and how we have responded in our revised TSSs.

Stakeholder	Issue raised	Our response
Department of Environment, Land, Water and Planning	Customers with an EV charger at their premises should be assigned to the new ToU tariff without the option to opt-out to a flat tariff	In subsequent discussion we understand that the Department intends to consult on provisions for EV charging. Since we are unsure of the final policy position we have not included anything specific in our revised TSS, but expect to update it once a policy position has been decided.
CAP	The CAP saw that the changing nature of tariffs clearly has a role to play in future networks and that we can be creative for how we provide solutions to customers and different customer segments	See section 3.1 regarding the role tariffs play in the future networks development. We will continue to explore tariff trials to ensure we addresses challenges of different customer segments appropriately
	The opportunities with tariffs are about the persons' ability to extract agency out of it. There is an opportunity now because of the falling electricity cost curve and more price elasticity. We were encouraged to examine price elasticity and how it can impact tariff reform	We have not been able to separate out or observe a noticeable level of price elasticity largely due to the large number of variables affecting consumption behaviour. This is something that we plan to more closely monitor over the next regulatory period.
	With regard to tariff reform, if customers changing their behaviour is a barrier for best outcomes to tariff reform, there may be opportunities from AI alleviating this barrier. However, AI is still a bit away in the future and appropriate communication in the meantime can assist with this behavioural change	We agree AI is likely to alleviate the barrier of smart device electricity usage. However we do not consider it likely this technology will be available over the next regulatory period, albeit possibly in the period after We will run a communication campaign about our new tariffs and how customers can change behaviour as a result in due course
Consumer Challenge Panel 17	There was concern about the impact of the TSS on vulnerable customers and a suggestion that further work is carried out to measure the effects on vulnerable customers, including: • a larger sample • matching the ratio of peak to off-peak rates to our proposals and a sensitivity analysis around that ratio • a seasonal variability analysis	As our TSS proposes the new TOU tariff is applies to new connections, supply upgrades and new solar connections, we believe this addresses the issues of vulnerability somewhat as we are not proposing to move existing vulnerable customers to the TOU tariff While our revised TSS does include a reassignment of legacy TOU customers to the new TOU tariff, section 3.2 indicates that bill impacts across the legacy TOU population is overwhelmingly a bill reduction. Those customers who are negatively impacted can still opt out to the single rate tariff Unfortunately, we have not had time to conduct a more detailed sensitivity analysis for the revised TSS
	The CCP17 highlighted the importance of the flat rate tariff offering a reasonable safety net for vulnerable customers. The more complex tariff should not be set at a discount to the flat tariff as that would detract from the effectiveness of the flat rate tariff as a safety net tariff	Our original and revised TSS propose a small differential between the new TOU and single rate tariffs. We believe this strikes the right balance between encouraging uptake of the new TOU tariff and the single rate tariff acting as a safety net.

	The CCP17 encouraged us to consider whether there is merit in exploring a solar sponge charging window for areas with a high concentration of residential consumers to address the falling minimum demand associated with increased penetration of solar	See section 3.1.5
Energy Consumers Australia	The ECA asked for further clarification on how meter replacements will be treated	Customers whose meter is replaced will remain on their existing tariff.
	The ECA proposed a voluntary EV 'prices to devices' cost-reflective tariff. This would see retailers of EV owners charged a low off-peak rate and a very high peak rate that is only charged 2% of the time. Energeia have calculated suggested fixed peak pricing periods for each distributor.	We agree that because EV charging is more flexible than other household electricity needs, a more cost-reflective tariff could be targeted at EVs. However, we don't believe that this can be achieved with fixed peak periods but rather that pricing will need to be dynamic. Neither distributors nor retailers are set up for dynamic pricing, so a trial is more appropriate at this stage. We are currently exploring a dynamic network tariff EV trial with relevant stakeholders.
	There was concern tariff reform has been relegated to 'the slow track' on the basis of protecting vulnerable customers	The residential tariff reforms we proposed reflect the consensus views of our stakeholders. Impacts of bulk mandatory tariff assignment was seen to be detrimental for a proportion of vulnerable customers.
	The ECA asked for further explanation of the tariff impact on the planned DER program	See section 3.1
	There was a question around why we chose consistency across every day of the week, rather than different pricing for weekends, and why we did not account for seasonality of peaks. A flat tariff with a seasonal peak is more like a demand tariff than a ToU tariff that applies throughout the year The ECA encouraged us to revisit this decision to ensure are not paying more than they need to, particularly on weekends (which account for 29% of the year) and in shoulder and winter periods (which account for two thirds of the year The ECA also stated it is important that networks consider the end-point for tariff reform so ensure that the transition path they plot is supportive of the end goal	Residential peak can occur on weekends and therefore we propose consistency across every day of the week. It is correct that a large proportion of peaks could be captured with a summer peak charge only. The trade off is simplicity which was the overarching desire from stakeholders. We therefore adopted the most simple tariff – a peak/off-peak period which is the same every day of the year We also note that the low rate around midday will also encourage households to move their solar production until after 3pm, thus encouraging lower solar exports around midday in all months of the year It is difficult to foresee the endpoint of tariff reform because community and political acceptance drive both the pace and direction of tariff reform. Additionally reform more across the national electricity market will likely dictate the future direction of tariff reform

	The ECA encouraged us to design specific tariffs for EV owners and support EV chargers being connected to a separate circuit. Given the potential for 'convenience charging' it would seem sensible for networks to have some control over vehicle charging to ensure that charging loads can be staggered rather than all turned on at the same time using a digital timer	We are currently in discussions with retailers to trial a dynamic network tariff for EV chargers
Victorian community organisations	Victorian community organisation asked we seek to better understand how different types of vulnerable consumers will be impacted and the impact of a proposed tariff structure on behaviour in vulnerable households	See response to similar issue raised by the CCP17
	There was a request for further analysis to determine how effective the TOU tariff – and the associated assignment arrangements – would be in enabling energy transition, and how the tariff would interact with other essential measures for managing EVs on the network	With the re-assignment of legacy tariffs to the new TOU tariff, nearly 20% of customers will transfer to the new TOU tariff on 1 July 2021. The Victorian Government plans to consult on assignment criteria for electric vehicle chargers. Our TSS will be updated to reflect their policy position.
	If tariffs allow some consumers to reduce their distribution charges by changing their behaviour, it is important to be confident that this will lead to benefits that are shared by all consumers. It is also important to be confident that shared benefits will outweigh the additional network costs borne by consumers unable to respond to the price signal	Cost-reflective pricing mitigates the risk of high demand growth / high future network investment. All customers are rewarded through less investment and therefore lower future network tariffs. These benefits are not expected to be large over the next five to ten years and therefore we have adopted a commensurate pace for tariff reform.
Electric Vehicle Council	There was a recommendation that a distinction is made between residential customers in standalone or semi-detached dwellings, and residential customers living in multi-residential strata developments, as TOU tariffs are unlikely to lead to modified behaviour for customers in a multi-residential dwelling with shared power	Our revised TSS only proposes to place separately metered fast EV chargers onto a TOU tariff so apartment dwellers are unlikely to be affected.
	There was a recommendation that further analysis and trials need to be undertaken to find the most cost-reflective tariff for high capacity EV charging	We are open to trials in the context of finding a cost-reflective tariff which is for the long term net benefit of our customers
AGL	Propose the better solution to addressing the 'duck curve' is a TOU tariff with a solar sponge as proposed by SA Power Networks	See section 3.1.5
	Suggest distributors should simplify the range of tariffs and all customers to cost reflective network tariffs. Retailers have the discretion to mirror network tariffs and are better placed to offer a range of retail tariff options to cater to different customer needs	Both vulnerable customer groups and the Victorian Government have expressed a desire that small customers be able to opt out of cost-reflective tariffs to a single rate tariff. This requirement is currently legislated and it is expected that the Victorian Government will extend this legislated requirement into the next regulatory period

	Because of the way the Victorian default offer (VDO) is priced, it is important to at least maintain parity of the flat and non-flat tariffs for the representative customer	We are proposing to price the new TOU tariff slightly cheaper than the single rate tariff to create a small incentive for retailers to select the new TOU tariff
Energy Australia	There was support for Powercor's proposed changes to its sub-transmission tariff by measuring kVA for its demand charge component from 8am and 8pm on workdays, and the proposed narrowing of the peak energy component of the tariff to the same time window	Consistent with Energy Australia's proposal, we have further narrowed the demand window by adopting the United Energy tariff structure. See our response to the draft determination on this issue
Red and Lumo Energy	Do not support mandated time of use tariffs as proposed, as it is likely to result in unintended consequences like tariff and bill shock, eroding trust in the energy market	Our proposed approach reflects years of collaborative stakeholder engagement and feedback. All customers will have the option to opt out to a single rate tariff
Evie Networks	Recommend the use of sub-threshold tariffs to trial alternative tariff structures for publicly available fast, and ultra-fast, EV charging sites	We are open to trials in the context of finding a tariff which is for the long term net benefit of our customers
	Recommends that the AER should endorse a redefinition of the Victorian distributors' eligibility criteria for small business customer tariff assignment. Specifically, the arbitrary capacity thresholds for default large customer assignment should not be applied to customers with low load factors (such as public fast and ultra-fast charging) given the long run marginal cost (LRMC) data reveals this practice to be inequitable for such customers and in direct contravention of the National Electricity Objective	Our costs are largely driven by how much capacity we need to build. Capacity is determined by the expected maximum coincident demand on a particular network element. Even if there is currently sufficient capacity in a particular part of the network, this capacity had to be constructed and the cost will now sit in our asset base. The fairest way of recovering this future or sunk cost is to base it on coincident demand, the driver of network investment Customers with low load factors and high demand, such as public EV charging infrastructure, impose large costs on the network if expressed on a per kWh basis. Therefore, it would neither be cost-reflective nor equitable to assign public EV charging infrastructure to energy-only tariffs with rates that have been calculated based on much higher load factors
	Maximum demand for the EV charging sites located at regional petrol stations is likely to correspond to periods of maximum traffic flows, for example during holiday periods. These periods do not coincide with periods of greatest network utilisation. The diversity between EV charging site demand and local maximum demand is not reflected in the present C&I tariff structures because these structures are not cost-reflective	We are proposing to change the way that demand is measured. This will provide customers with the opportunity to pay lower network charges if their maximum demand is not coincident with typical network maximum demand periods
	Network congestion is more likely driven by small customer demand profiles than C&I demand profiles. However, C&I tariff designs have the effect of allocating a substantially higher proportion of total distributor marginal costs to C&I tariffs	In our 2021 pricing proposal, the average unit cost (total network revenue divided by energy usage) for a residential customer is ~9 c/kWh while it is ~6 c/kWh for a low voltage C&I customer

	C&I customers are more likely to use dedicated connection assets. Where this occurs, the capital expenditures are not standard control services and outside the regulated cost base and excluded from the LRMC component of total regulated revenues. Only operating costs for dedicated connection assets are recovered from standard control tariffs	Dedicated connection assets are standard control services. Distribution charges fund the difference between construction cost and the customer contribution. Except in rare circumstances, all connecting customers make a contribution towards the construction cost of their connection
Evie Networks (Sapere)	The current approved TSSs do not appear consistent with the National Electricity Law (NEL) requirements that tariffs are based on the LRMC. Data from network revenue models show large discrepancies between LRMC as a proportion of regulated costs and the LRMC component of expected revenue from tariffs Current tariff structures are resulting in excessive prices for customers whose demand is infra-marginal, alongside under-recovery of marginal costs for customers whose demand is marginal. This shifts total network costs between customer segments in ways that produce outcomes (energy prices and customer bills) that are inconsistent with the long-term interests of customers A substantial reduction in bills for EV charging sites would not represent a cross-subsidy from other customer classes. Rather, it would represent removal of the substantial cross subsidy from EV charging sites both under current, and proposed, TSS	LRMC can be calculated in different ways resulting in different outcomes. The LRMC calculated for our network is in the range of LRMC calculated for other Australian networks The concern around excessive prices and cross-subsidies derives from Sapere's view that the proportion of revenue recovered through LRMC is too high because the calculated LRMC is too high. We do not consider this to be true. Darryl Biggar of the ACCC said in a recent EV network tariff meeting that he would expect the LRMC to be greater than 50% of revenue whereas Sapere say it is 10-15%
	There are significant inconsistencies between networks regarding tariff assignment policies for the candidate sites. The sites are assigned to C&I tariffs for four of the five Victorian DNSPs (Powercor, Citipower, Jemena and United Energy), even though the anticipated volumetric consumption of these sites is well below the volumetric threshold for large customer assignment	Our costs are largely driven by how much capacity we need to build. Capacity is determined by the expected maximum coincident demand on a particular network element. Even if there is currently sufficient capacity in a particular part of the network, this capacity had to be constructed and the cost will now sit in our asset base. The fairest way of recovering this future or sunk cost is to base it on coincident demand, the driver of network investment Customers with low load factors and high demand, such as public EV charging infrastructure, impose large costs on the network if expressed on a per kWh basis. Therefore, it would neither be cost-reflective nor equitable to assign public EV charging infrastructure to energy-only tariffs with rates that have been calculated based on much higher load factors