DRAFT DECISION

AusNet Services, CitiPower, Jemena, Powercor, and United Energy
Distribution Determination
2021 to 2026

Attachment 19
Tariff structure statement

September 2020

AUSTRALIAN
ENERGY
REGULATOR

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Note

This attachment forms part of the AER's draft decision on the distribution determination that will apply to AusNet Services, CitiPower, Jemena, Powercor, and Untied Energy for the 2021–26 regulatory control period. It should be read with all other parts of the draft decision for each distributor.

The draft decision includes the following attachments:

Overview

Attachment 1 – Annual revenue requirement

Attachment 2 – Regulatory asset base

Attachment 3 – Rate of return

Attachment 4 – Regulatory depreciation

Attachment 5 – Capital expenditure

Attachment 6 – Operating expenditure

Attachment 7 – Corporate income tax

Attachment 8 – Efficiency benefit sharing scheme

Attachment 9 – Capital expenditure sharing scheme

Attachment 10 – Service target performance incentive scheme

Attachment 11 – Demand management incentive scheme and demand management innovation allowance mechanism

Attachment 12 - Customer service incentive scheme (applicable to AusNet Services only)

Attachment 13 – Classification of services

Attachment 14 – Control mechanisms

Attachment 15 – Pass through events

Attachment 16 – Alternative control services

Attachment 17 – Negotiated services framework and criteria

Attachment 18 – Connection policy

Attachment 19 – Tariff structure statement

Attachment A – Victorian f-factor incentive scheme

Contents

19 Tariff structure statement

This attachment sets out our draft decision on the Victorian electricity distributors' proposed tariff structure statements to apply for the 2021–26 regulatory control period.

A tariff structure statement applies to a distributor's tariffs for the duration of the regulatory control period. It describes a distributor's tariff classes and structures, the distributor's policies and procedures for assigning customers to tariffs, the charging parameters for each tariff, and a description of the approach the distributor will take to setting tariff levels in annual pricing proposals. It is accompanied by an indicative pricing schedule.[1]

A tariff structure statement provides consumers and retailers with certainty and transparency in relation to what network tariff structures will be charged to retailers for different types of customers over the five year period for which it applies. It also explains how a distributor's tariff strategy aligns with other initiatives it is undertaking, such as the management of distributed energy resources and demand management.

Network tariffs which signal the costs (capital and operating) that different patterns of customer behaviour impose on the network support the efficient and effective transformation of the energy sector. They enable decisions as to which network costs should be incurred to better serve customers and how to reward changes in behaviour that reduce or avoid these costs. This allows customers, retailers, and other market participants to maximise the benefits of new and emerging energy technologies and business models.

This evolution of networks as platforms for energy services is also supporting innovation in energy retail and service products for consumers. We are seeing new services provided by market participants who can leverage cost reflective network price signals to reduce costs not only for their clients but also for the networks themselves.

We expect these trends to continue as the National Electricity Market (NEM) transforms from the old model of one-way power supply to a new two-sided market model enabling customers to actively participate in the supply and optimisation of energy resources. Network tariff reform is integral to this transition of Australia's domestic energy sector.

In driving tariff reform, it is important to note that distributors directly charge retailers for the network services provided to end-customers and there is no obligation on retailers to pass the network tariff structure through to their end-customers. The structure of retail prices should be determined in the market by retailers responding to consumer preferences and competitive pressures. Accordingly, consumers should be able to request a flat rate retail offer if they would prefer retailers to manage network price risk

[1] NER, cl. 6.18.1A(e).

for them.[2] This does not mean that retailers should ignore network price signals. Quite the reverse. Retailers should consider the full range of measures available to them to manage network price signals (in addition to their other costs such as wholesale electricity costs).

For example, retailers may use non-price measures such as well targeted demand management initiatives to manage their commercial risks. Retail packages incorporating energy storage are another means of managing network price signals. Retailers may also be encouraged to pass through cost reflective network tariff structures to end-customers if they consider customers are well placed to respond and be rewarded for doing so. At present, it is more common for retailers to pass through the cost reflective network tariff structures to large business customers than for residential or small business customers.[3]

In establishing network tariff structures, distributors should provide retailers with better price signals about the costs associated with provision of electricity network services. This will ensure that retailers make informed decisions about how best to manage the financial risks under more cost reflective network pricing. The competitive retail market helps promote an outcome where retailers make these decisions in a manner that takes into account the preferences of their end-customers.

19.1 Draft decision

Our draft decision is to not approve the Victorian distributors' proposed tariff structure statements, as we are not satisfied they comply with the pricing principles for direct control services in the National Electricity Rules (NER).[4]

Although we are satisfied that most elements of the proposed tariff structure statements contribute to compliance with the pricing principles for direct control services and to the achievement of the network pricing objective, we consider that some elements require amendment, further detail, or additional supporting justification.

We consider the following elements of the Victorian distributors' tariff structure statement proposals contribute to compliance with the pricing principles for direct control services including:

- the new time of use tariff for residential customers with a 3pm to 9pm every day peak period
- the new time of use tariff for small business customers with a shorter peak period of 9am to 9pm

2 The ACCC's 2018 Retail Electricity Pricing Inquiry Final Report provides further guidance on this.

3 We interviewed retailers and energy service providers to support our decisions on tariff structure statements for networks in South Australia and Queensland. A summary is available on our Network Tariff Reform webpage at https://www.aer.gov.au/networks-pipelines/network-tariff-reform.

4 NER, cll. 6.12.3(k) and 6.12.1(14A).

- retention of flat tariff and monthly peak demand tariff options for residential customers
- discounting residential customer cost reflective tariffs to incentivise take-up
- tariff assignment policies, including moving from opt in assignment for the new time of use tariff to opt out for new customers or customers who make a significant change to their connection
- retention of the existing cost reflective tariffs for medium and large business customers
- pursuing more locational, targeted responses through complementary demand management and DER related strategies
- methods for estimating long run marginal cost (LRMC).

We require the following changes to achieve compliance with the pricing principles for direct control services including:

- AusNet Services to discount its residential time of use and demand tariffs relative to its flat tariffs to incentivise take up of cost reflective tariffs
- AusNet Services to allow residential solar PV customers to opt-out to a flat tariff
- United Energy to amend its proposed flat tariff for medium sized business customers to include cost reflective elements (such as a demand charge or critical peak pricing) or remove that tariff
- AusNet Services to introduce additional tariff choice for medium business customers in addition to the proposed default tariff
- the five Victorian distributors to introduce tariff choice for large business customers in addition to the proposed default tariff in the form of individually calculated customer (ICC) tariffs.

We suggest the Victorian networks consider the following elements of their tariff structure proposals with a view to making further improvements including:

- closing the legacy tariffs and reassigning those customers to the new time of use and demand tariffs
- amending peak charging windows for business customers to potentially make these more targeted
- in revised proposals, a statement on how tariff proposals are integrated with demand management and other initiatives
- CitiPower, Powercor and United Energy consider a larger peak to off peak ratio for their small customer cost reflective tariffs to more closely align with their historical values, as well as the ratios proposed by AusNet Services and Jemena
- continued exploration of including replacement capital expenditure into estimates of LRMC.

On the issue of network tariffs applicable to grid scale storage (batteries) positioned on the Victorian distribution networks or behind customer connection points, we do not make a draft decision. Rather, we encourage stakeholder submissions on the options set out in section 19.4.2 of this attachment.

19.2 Victorian distributors' proposal

The key elements of the Victorian distributors' tariff structure statement proposals are summarised below.

Residential and small business customers up to 40 MWh per year

For residential and small business customers consuming less than 40 MWh per year the five Victorian distributors collaborated and presented an aligned tariff structure statement proposal. The main elements of that aligned proposal were:

- for residential customers, a new two-rate time of use tariff with a 3pm to 9pm every day peak period with:
  - default assignment to this tariff for customers who upgrade to three-phase power supply, install solar PV or batteries, or become electric vehicle customers[5], as well as for new connections
  - opt-in for any other customers
  - any customer on this tariff may opt-out to either a single rate (flat) tariff or to a demand network tariff
- for residential customers, the legacy time of use tariffs are proposed to be closed to new customers
- for small business customers consuming less than 40MWh per year, an amended time of use tariff with a shorter peak period of 9am to 9pm on business days with:
  - default assignment to this tariff for customers who upgrade to a three-phase power supply and/or install solar PV, as well as for new connections
  - reassignment to this tariff for customers on the legacy small business time of use tariffs which will be closed.

Business customers consuming more than 40MWh per year and less than 160 MWh per year

CityPower, Powercor and United Energy

No changes are proposed.

[5] Assignment of customers with EVs to this tariff requires such customers to be identifiable, for example via an EV customer register. Such a register is not currently available.

AusNet Services

No changes are proposed.

Jemena

No changes to tariff structure or assignment policy are proposed. The measurement of demand is proposed to change from ongoing ratcheting to a 12 month rolling average. All peak periods are proposed to change from Australian Eastern Standard Time (AEST) to local time.

Large business customers consuming more than 160 MWh per year

CityPower, Powercor and United Energy

It is proposed to change the demand charge from any time to a charging window of 8am to 8pm on business days.

AusNet Services

No changes are proposed.

Jemena

No changes to tariff structure or assignment policy are proposed. The measurement of demand is proposed to change from ongoing ratcheting to a 12 month rolling average. All peak periods are proposed to change from AEST to local time.

19.3 Assessment approach

This section outlines our approach to the assessment of tariff structure statements.

There are two sets of requirements for tariff structure statements. First, the NER set out a number of elements that an approved tariff structure statement must contain.[6] Second, a tariff structure statement must also comply with the pricing principles for direct control services.[7]

What must a tariff structure statement contain?

The NER require a tariff structure statement to include:[8]

- the tariff classes into which retail customers for direct control services will be divided
- the policies and procedures the distributor will apply for assigning retail customers to tariffs or reassigning retail customers from one tariff to another

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6 NER, cl. 6.18.1A(a).

7 NER, cl. 6.18.1A(b).

8 NER, cl. 6.18.1A(a).

- structures for each proposed tariff
- charging parameters for each proposed tariff
- a description of the approach that the distributor will take in setting the price level of their tariffs in the pricing proposal for each regulatory year during the 2021–26 regulatory control period.

A distributor's tariff structure statement must be accompanied by an indicative pricing schedule with the tariff structure statement.[9] This schedule guides stakeholder expectations about annual changes in the price level of network tariffs over the 2021–26 regulatory control period. As a result, we require that the annual prices in the indicative pricing schedule be based on the proposed methodologies in the tariff structure statement for signalling LRMCs and the efficient recovery of residual costs.

What must a tariff structure statement comply with?

A tariff structure statement must comply with the pricing principles for direct control services.[10] These may be summarised as:

- for each tariff class, expected revenue to be recovered from customers must be between the stand alone cost of serving those customers and the avoidable cost of not serving those customers[11]
- each tariff must be based on the LRMC of serving those customers, with the method of calculation and its application determined with regard to the costs and benefits of that method, the costs of meeting demand from those customers at peak network utilisation times, and customer location[12]
- expected revenue from each tariff must reflect the distributor's efficient costs, permit the distributor to recover revenue consistent with the applicable distribution determination and minimise distortions to efficient price signals[13]
- distributors must consider the impact on customers of tariff changes and may depart from efficient tariffs, if reasonably necessary, having regard to:[14]
    - the desirability for efficient tariffs and the need for a reasonable transition period (that may extend over one or more regulatory periods)
    - the extent of customer choice of tariffs
    - the extent to which customers can mitigate tariff impacts by their consumption

9 NER, cl. 6.18.1A(e).
10 NER, cl. 6.18.1A(b).
11 NER, cl. 6.18.5(e).
12 NER, cl. 6.18.5(f).
13 NER, cl. 6.18.5(g)
14 NER, cl. 6.18.5(h).

- tariff structures must be reasonably capable of being understood by retail customers assigned to that tariff[15]
- tariffs must otherwise comply with the NER and all applicable regulatory requirements.[16]

The tariff structure statement must comply with the pricing principles for direct control services in a manner that will contribute to the achievement of the *network pricing objective*:[17]

> The network pricing objective is that the tariffs that a distributor charges in respect of its provision of direct control services should reflect the distributor's efficient costs of providing those services to the retail customer.[18]

Role of the Tariff Structure Statement

In 2014, the Australian Energy Market Commission (AEMC) made important changes to the distribution pricing rules, including the process through which network tariffs are determined. This included splitting the network pricing process into two stages.

Table 19.1 Two stage network pricing process

Stage	Requirements
First stage	Distributors develop a proposed tariff structure statement to apply over the five year regulatory control period. The tariff structure statement outlines the distributor's tariff classes, tariff structures, tariff assignment policy and approach to setting tariff levels in accordance with the pricing principles for direct control services. The tariff structure statement is accompanied by an indicative pricing schedule that sets out expected price levels over the five year proposal. This document is submitted to the AER for assessment against the pricing principles for direct control services in conjunction with the distributor's five year proposal. The AER then approves the tariff structure statement if it meets the pricing principles for direct control services and other NER requirements.
Second stage	Distributors develop and submit their annual pricing proposals to the AER. The annual pricing proposals essentially apply pricing levels to each of the tariff structures outlined in the approved tariff structure statement. Distributor's proposed pricing levels must be consistent with the indicative pricing schedule, or the distributor must explain why its proposed price levels differ from the indicative pricing schedule.

15 NER, cl. 6.18.5(i)

16 NER, cl. 6.18.5(j); this requirement includes jurisdictional requirements.

17 NER, cl. 6.18.5(d).

18 NER, cl. 6.18.5(a).

Stage	Requirements
	The AER's assessment of the distributor's pricing proposal is a compliance check against the approved tariff structure statement and the control mechanism specified in the AER's regulatory determination.

Source: AER.

Splitting the network pricing process into two stages was a significant change from the previous arrangements. The AEMC considered this would promote several objectives and allow for:

- requirements that would facilitate meaningful consultation and dialogue between distributors, the AER, retailers, and consumers
- increased certainty with respect to changes in network tariff structures and more timely notification of approved changes to network tariff pricing levels
- more opportunity for retailers and consumers to inform and educate themselves about how network tariffs will affect them and how they should respond to the pricing signals
- the AER to have appropriate timeframes and capacity to assess the compliance of the distributors proposed network tariffs against the pricing principles for direct control services and other requirements
- distributors to maintain ownership of network tariffs and to adjust the pricing levels of their tariffs to recover allowed revenues.[19]

19.4 Reasons for draft decision

We outline below our draft decision on each element of the Victorian distributors' tariff structure statement proposals.

This section is structured as follows:

- residential and small business customer tariffs
- medium and large business customer tariffs
- LRMC methodology
- statement structure and completeness.

We have included Appendix A which describes key elements of the electricity sector relevant to the Victorian distributors' tariff structure statement proposals and our draft decision.

[19] Australian Energy Market Commission, *Rule Determination - National Electricity Amendment (Distribution Network Pricing Arrangements) Rule 2014*, November 2014, p. 64.

Two further documents relevant to our assessment, which in the past have also formed appendices to our tariff structure statement draft decisions, will be made available as stand-alone documents on the AER webpage for network tariff reform:

- Tariff design and assignment policy principles
- LRMC.[20]

19.4.1 Residential and small business tariffs

We consider the aligned tariff strategy for small users proposed by the five Victorian distributors balances the need to progress network tariff reform while bearing in mind customers' ability to understand and respond to the tariff signals. The Victorian distributors also responded to a number of points in our guidance from the first round of tariff structure statements on improvements we expected in future iterations.

The elements of the proposals for residential and small business customers which we consider contribute to achievement of compliance with the pricing principles for direct control services are:

- engaging with stakeholders through a series of fora and consultations to ensure customer preferences shaped the tariff strategy
- moving from an opt-in to opt-out approach to tariff assignment to increase the number of customers whose retailers will need to manage cost reflective network tariffs
- introducing discounts for cost reflective network tariff options to incentivise greater take up of these tariff structures
- refining the charging windows for the tariff structures and targeting this at the greatest incidence of coincident peak across the state
- pursuing more locational, targeted responses through complementary demand management and distributed energy resource (DER) related strategies.

We discuss these issues further in the sections below.

Tariff design, levels and charging windows

In this section we discuss the reasons for our draft decision on the proposed structures of residential and small business customer tariffs.

We support engaging with stakeholders to develop the tariff strategy

For these tariff structure statements, the Victorian distributors collaborated to hold a series of forums with a wide range of stakeholders. The fora evolved from discussing the objectives of network tariff reform to who should be the focus of tariff reform, before drawing these together to explore the appropriate structures. Following this

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[20] AER website: https://www.aer.gov.au/networks-pipelines/network-tariff-reform.

stakeholder consultation, the Victorian distributors prepared and circulated discussion papers on residential and small business tariff strategies. These were the basis of further refinements to their tariff structure statement proposals. Moreover, this work was translated into the five distributors producing consistent explanatory documents to provide the narrative to accompany their tariff structure statement proposals.

The result is that the distributors proposed to simplify their residential tariff offers to a flat rate network tariff, a time of use tariff and a demand tariff. The time of use tariff will be the default for customers changing their behaviour (e.g. new connection or upgrade to three phase) while existing customers will remain on the equivalent tariff to the tariff they are currently assigned to. All customers and their retailers will have the ability to choose between all three tariffs as all customers in Victoria have the smart meter infrastructure required to apply these structures.

We commend the distributors for their efforts to streamline points of engagement to allow resource constrained customers, advocates, community groups, and other key stakeholders to engage. We are also encouraged to see genuine efforts to use the stakeholder preferences and expectations expressed through this engagement to shape their subsequent tariff structure statement proposals. While network tariffs are targeted at retailers who package them with other costs, we have not yet seen wide-scale innovation in the retail offers for customers. With most retailers maintaining a flat rate retail offer or passing through the network tariff structures, there is greater need to consider the preferences of, and impact on, end customers.

We acknowledge statewide charging windows as a reasonable trade-off

As part of the Victorian distributors' coordinated engagement, stakeholders expressed a strong desire for state-wide charging windows for small users. We received a number of submissions supporting this element of the proposals.[21] While this means the tariff structures are not as cost reflective as they could be, as they do not reflect differences between the five Victorian distribution networks, we consider this is a reasonable trade-off at this stage of the tariff reform process. The proposed consistent approach means that stakeholders working across the five Victorian network areas to help customers understand and respond to price signals have only one suite of tariff structures to familiarise themselves with.

We are encouraged that the distributors looked at their collective circumstances across Victoria and narrowed the network peak period significantly from the 7am to 11pm currently in place to 3pm to 9pm. The peak should be focused on signalling when the network may be constrained and there would be a benefit (through avoided costs) from customers shifting or reducing their consumption. There is also an emerging need to encourage customers to shift consumption to periods when solar PV output is high to help address voltage and other issues. Shorter peak periods also allow for a sharper

[21] For example see the submissions from CCP17 and Red and Lumo Energy on the Victorian distributors' tariff structure statement proposals

price signal to be used which increases the benefit customers receive from responding to the peak period price signal.

A number of stakeholders submitted that the distributors should consider introducing a solar sponge component to the time of use tariff.[22] We note that the penetration of solar PV in Victorian distribution networks is, in proportionate terms, currently lagging networks in South Australia and Queensland. However we encourage the Victorian distributors to continue to monitor this issue for further consideration, noting that the Victorian Government's Solar Homes Program is intended to fund solar PV installations for almost one in four households by 2028–29.[23]

Higher peak to off-peak ratios reward response

In their proposed tariff structure statements, CitiPower, Powercor, and United Energy proposed tariff structures with a peak to off-peak ratio of 2.5 for residential customer tariffs. In contrast, Jemena proposed a ratio of around 3, while AusNet Services proposed a ratio closer to 5 which effectively maintains the ratios their customers have been facing during the current regulatory control period (2016–20).

For small business tariff structures, AusNet Services proposed a peak to off-peak ratio of 4.4, CitiPower 2.5, Jemena 5.1, Powercor 4.5, and United Energy 4.5. These proposed ratios are broadly consistent with the ratios AusNet Services, Jemena, and Powercor's customers currently face, but are a reduction for CitiPower and United Energy's customers.

The use of peak to off-peak ratios of around 2.5 for residential and around 4.5 for small business tariffs is a result of the early engagement with customers. These ratios were established to inform the assumptions underpinning the consumer impact analysis undertaken by distributors and allow for comparison between the distributors. But they were not aligned with the historical ratios residential customers and their retailers have been engaging with during the 2016–20 regulatory control period.

For example, in their 2020 annual pricing proposals the five distributors' approved peak to off-peak ratios for residential customers averaged around 5, ranging from 3.8 for CitiPower's tariffs (C2R and C3R) to 6.4 for United Energy's tariff (LVS2R). The equivalent ratio for small business users averaged 4.6, ranging from 3.2 for CitiPower's tariff (C2G5) to 6.3 for the summer component of United Energy's tariff (LVM2R5D).

As distributors' tariffs are set to recover their regulated revenue requirement, to reduce the ratio from the rates in tariffs for the current regulatory period, the off-peak rate must be increased relative to the current period. This means that customers will receive a weaker incentive to change their behaviour and reduce investment requirements, as well as facing higher prices for consumption that is not driving network costs.

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22 Submissions from CCP17 and AGL explicitly called for a solar sponge tariff to be considered.

23 This initiative is funding 700,000 solar PV systems and, with the Victorian Government estimating around 2.9 million households in 2026 in their Victoria in Future work, this equates to almost one in four households.

We consider the proposed ratios to be reasonable. However we encourage CitiPower, Powercor, and United Energy to continue with their review of their proposed ratios. We note that small users and their retailers will be given a choice between flat rate, time of use, and demand tariff structures to help them decide what will work best for them. We also consider at least maintaining the current ratios would be more consistent with the pricing principles for direct control services which require distributors to progress along the path to more cost reflective network tariffs with each round of tariff structure statements.

Accompanied by discounts to incentivise take up of cost reflective tariffs

CitiPower, Jemena, Powercor, and United Energy proposed to discount their residential cost reflective tariffs (demand and time of use tariffs) relative to their flat rate tariffs to incentivise the take-up of cost reflective tariffs. Using a glide path of 1 per cent per year for each year of the regulatory control period, these tariffs will be priced 5 per cent below the flat rate alternative by 2025–26. This will result in around 80 per cent of customers being better off on the cost reflective network tariffs. AusNet Services did not propose a discount. However, we understand it is considering introducing one with its revised proposal.

As we have established in our recent decisions for distributors in New South Wales and Tasmania, when customers and their retailers are provided with access to a flat rate network tariff we think it is appropriate for networks to incentivise uptake of more cost reflective options.[24] We consider this to be consistent with the obligation on networks to progress network tariff reform, varying only to reflect the extent to which customers can understand and manage these price signals.[25] In other networks where customers and their retailers have not been provided with access to a flat rate network tariff we have not considered this necessary.

We consider AusNet Services should also adopt a similar discount policy for its cost reflective residential tariffs as part of its revised tariff structure statement proposal.

Complementary initiatives to address specific locational issues

We are encouraged to see the distributors exploring a number of initiatives to target locational issues alongside the general network tariff structures for small users. This includes demand management initiatives funded by the demand management incentives and allowances provided under the NER,[26] directly by the distributors, and through organisations like the Australian Renewable Energy Agency (ARENA). The distributors have also been undertaking education programs.

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[24] See our draft and final decisions on the 2019–24 tariff structure statements for Essential Energy, Endeavour Energy, and TasNetworks.

[25] NER cl. 6.18.5(h).

[26] The demand management incentive scheme (DMIS) and demand management incentive allowance mechanism (DMIAM) are covered in Attachment 11 of the draft decision.

It is particularly encouraging to see the non-network solutions developed under the demand management initiatives being refined and translated into business as usual practices. For example, United Energy's Summer Saver trial was turned into a business as usual program to defer low voltage augmentation on the Mornington Peninsula. AusNet Services noted in its proposal that it used the insights from the Peak Partners program funded under the demand management incentive allowance (precursor to demand management innovation allowance mechanism) in developing its GoodGrid program.

The five distributors have also committed to exploring complementary measures to support their tariff structures. These include literacy programs, technology rebates, energy efficiency programs, and peak time rebates. The distributors intend to collaborate and share the learnings from their experiences to date. For example, Powercor trialled a bill literacy program in partnership with the Australian Energy Foundation and the Western Bulldogs Football Club which had saved around $22,000 for the 68 customers involved. Jemena also noted that its People's Panel recommended Jemena dedicate funding to energy literacy and awareness programs. These initiatives, particularly when run in collaboration with retailers and community groups who are the interface with end users, enable customers to maximise the benefits of network tariff reform.

Tariffs, demand management, and broader DER strategies need to be more clearly integrated

We consider the Victorian distributors are progressing network tariff reform and are working to facilitate the emergence of distributed energy resources. However, we think attention should be given to ensuring these measures are developed as an integrated strategy and clearly communicated to stakeholders.

A tariff structure statement covers primary tariffs for standard control services and other elements of pricing such as secondary tariffs for controlled load. While CitiPower, Powercor, and United Energy discuss the potential for controlled load under their Digital Networks initiative, these tariffs could only progress if included in the proposed tariff structure statement and approved.

A tariff structure statement should also set out a distributor's broader strategy to pricing which will govern its businesses plans and operations over the regulatory control period (and potentially beyond). This includes how the distributors intend to manage increasing volumes of solar PV, customer batteries, and electric vehicles (EV). It would be helpful for the distributors to provide more detail on how they plan to refine and apply this strategy over the regulatory control period, such as through trials under the sub-threshold tariff clause.

Additionally, in procuring demand management the distributors set a value as to the benefit the network would receive from a change in customer behaviour. For example, demand management may be used to avoid or postpone augmentation expenditure in the same way that cost reflective tariffs can do. We encourage the distributors to explicitly integrate their approaches to tariffs and demand management.

Tariff assignment policy

The proposed approach is reasonable for this point in the reform process

Our draft decision is to accept the Victorian distributors' small customer tariff assignment policy subject to a requirement that AusNet Services allow residential solar PV customers to opt-out to a flat tariff. We also encourage the distributors to consider closing their legacy time of use tariffs and reassigning those customers to the new time of use tariffs.

The distributors proposed that small users in the residential and small business tariff class remain on the equivalent of the tariff they are currently assigned to. However, new connections and customers who change their connection (e.g. upgrade to three-phase) were proposed to be assigned to the new default time of use tariffs.
As proposed, all customers and their retailers may request to be reassigned to the flat rate, time of use, or demand network tariff structures. Customers with EVs, should they become identifiable, were proposed to be mandatorily assigned to the time of use tariff with access to the demand tariff as an alternative.

We accept the proposed assignment policies for small users subject to requiring AusNet Services to allow solar PV customers, and their retailers, access to the flat rate network tariff structure.[27] While we appreciate AusNet Services' intention to progress network tariff reform by allowing solar PV customers to access only cost reflective network tariffs, we think that at this stage of the reform process it would be appropriate to permit broader choice. However, assignment to these tariffs should be supported by AusNet Services also introducing a discount for the more cost reflective tariffs to incentivise customers to remain on these tariffs.

Distributors should consider reassigning those on legacy tariffs

While the distributors proposed to refine their small user tariffs to a choice between: a flat rate, a time of use, or a demand structure, they proposed to keep customers on legacy tariffs such as the legacy time of use. We consider this may not be consistent with progressing network tariff reform. It may also represent a missed opportunity.

Figure 19.1 below shows the expected assignment rates of customers to cost-reflective (blue), non-cost-reflective (grey), and legacy (orange) tariffs over the regulatory control period. Based on the proposed assignment policies, by 2025–26 the distributors expect around 10 per cent of customers to be on the cost-reflective network tariffs. While this is around double the current proportion, were the customers on legacy tariffs to be reassigned to the more cost reflective network tariffs the assignment rate would be around 26 per cent.[28] This is equivalent to where Ergon Energy and Essential Energy

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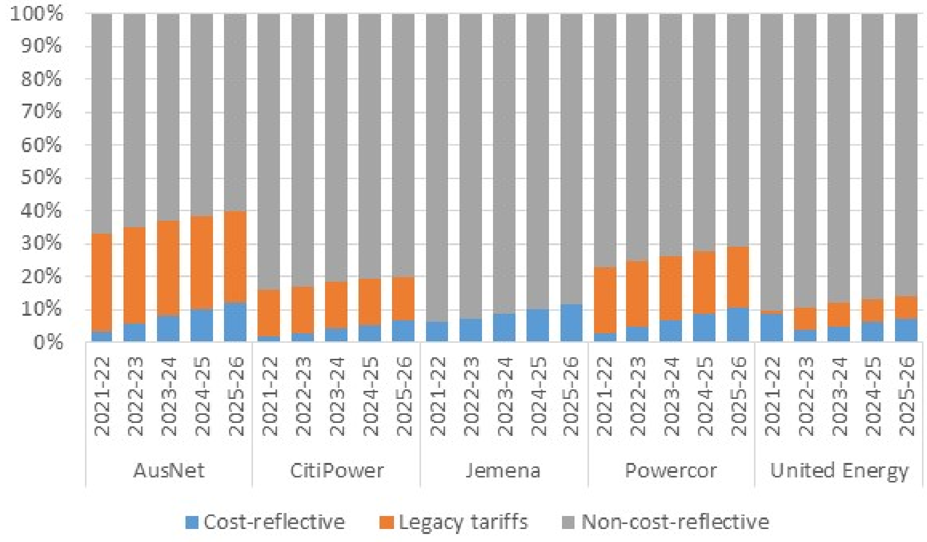
[27] We note that submissions from DELWP, ECA and Red and Lumo Energy all called for these customers to be provided with access to the flat rate tariff should this suit the customer's needs better.

[28] We note the ECA acknowledged these faster uptake rates and republished our graphic showing the progression of network tariff reform in the rest of the NEM in their submission on the Victorian tariff structure statement proposals

are expected to be at the end of their regulatory control periods but still behind the 50 per cent expected for SA Power Networks and Ausgrid.

Figure 19.1 Percentage of residential customers whose retailer will face cost reflective network tariffs by distributor



Source: AER analysis of data provided by distribution businesses.

We note that the Victorian distributors proposed to retain the legacy tariffs because some stakeholders are concerned about the potential customer impact of reassignment. However, a number of factors support reassignment occurring at the start of the 2021–26 regulatory control period. These include:

- expected reductions in the revenue requirements for all Victorian distribution businesses
- increasing the network tariff peak to off-peak ratios to align with those currently in place
- discounting the cost-reflective options relative to the flat rate tariff structure
- customers and their retailers maintaining access to the flat rate and demand tariff structures.

We also note that network tariff structures are charged to retailers who then package these costs with other elements, such as wholesale costs, into a retail offer for the end customer. Customers can choose the retail tariff structure that best suits their needs and preferences. These can be broadly grouped into either:

- insurance style flat rate retail offers
- pass-through of the underlying costs and structures, or
- energy services to manage customers' smart devices for them - colloquially known as 'prices for devices'.

The Victorian government has a number of complementary measures to ensure customers are in control of their retail offer and to support vulnerable customers. For example, the 2013 Advanced Metering Infrastructure (AMI) Orders in Council (amended in 2015, 2016, and 2017) prevent retailers from moving customers to pass-through structures without their consent. These Orders in Council also provide customers with the right to access their consumption data which is vital to understanding which retail offers best suit them. While these Orders in Council are due to sunset at the end of 2020, we understand the Department of Environment, Land, Water and Planning (DELWP) is considering how these protections may be maintained.

Additionally, the Victorian Default Offer (VDO) provides 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. Their decisions can be informed by the Victorian Energy Compare tool maintained by DELWP to help customers to compare the impact of the different retail offers available based on their consumption data.

In light of the above customer supports in Victoria, we encourage the distributors to revisit their proposed assignment policies and consider whether the legacy tariffs should be continued into the 2021–26 regulatory control period. We note that there may be a rationale for AusNet Services to exempt customers on its NEE24 tariff. This tariff is not a standard legacy time of use tariff but rather a primary controlled load tariff for rural customers. In exchange for allowing AusNet Services control of their heating between 8pm and 8am customers receive discounted tariff levels. While we accept this tariff's retention, we encourage AusNet Services to clarify how the discounts are set and whether they are reflective of the network benefit.

In encouraging the Victorian distributors to consider reassigning those on the legacy cost reflective tariffs, we also encourage them to explore whether 1 July 2021 or 1 July 2022 would be more appropriate for this reassignment. In our recent decisions for distributors in South Australia and Queensland we delayed the mandatory reassignment of customers to cost reflective tariffs by 12 months given the context for those determinations. In the Victorian context we consider reassignment of legacy time of use customers should be considered in relation to the expected movements in network revenues. In particular the expected change in revenue between the six month extension period and the commencement of the regulatory control period on 1 July 2021 should inform the distributors' revised proposals.

Additionally, we encourage distributors to engage with all relevant stakeholders on this issue. We note that AGL suggested that customers on legacy time of use and flexible tariffs be reassigned while EnergyAustralia requested the distributors to communicate what the impact is in terms of the bill impacts the customers might actually see.[29] Accordingly we think the customer impact analysis undertaken in relation to the impact

29 AGL and Energy Australia submissions on the Victorian distributors' tariff structure statement proposals.

of reassigning all customers on these legacy tariffs to the new cost reflective tariffs should be redone. But this should be with a focus on reassigning those on legacy tariffs, taking account of the change in revenue between periods, and reflect the proposed peak to off-peak ratios.

Tariff trials can help inform future strategies

In their tariff structure statement proposals the distributors expressed interest in exploring network tariff trials during this regulatory period. For example, we understand they have been engaging with Energy Consumers Australia (ECA) on its proposed electric vehicle tariff to consider whether this could be adopted as a tariff offer or trialled during the regulatory control period. However, significant detail remains to be clarified regarding how this tariff may be applied.

The Victorian distributors have also been engaging in the Distributed Energy Integration Program (DEIP) EV taskforces to share learning and explore potential future tariffs. We encourage them to continue to engage through these processes. We agree with the Electric Vehicle Council's submission that this provides a systematic and efficient way to build knowledge and understanding of what may be possible for the next regulatory control period.[30]

However, one of the major obstacles to network tariff reform is the uncertainty regarding how these tariff structures will be priced into retail offers for the end customers. To this end we commissioned a report from Baringa to improve our understanding of the potential cost savings from potential ‘prices for devices’ retail offers. While the results are indicative and subject to a number of assumptions, it is worth noting that our initial analysis suggested retailers can create value to share with customers without impacting the customer's experience.[31]

We believe tariff trials are a valuable tool for exploring alternative arrangements and building distributor, retailer, and consumer understanding of how these alternative arrangement may work in practice.[32] However, distributors should outline their intentions and strategy in their tariff structure statement proposals so this can be done in a systematic, transparent manner.

19.4.2 Medium and large business tariffs

This section of our draft decision covers our assessment of the Victorian distributors' tariff proposals relating to medium and large business customers in the 2021–26 regulatory control period.[33]

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[30] The Electric Vehicle Council's submission on the Victorian distributors' tariff structure statement proposals outlines further detail regarding these taskforces.

[31] See our Network Tariff Reform webpage for Baringa's report on the Value of Optimised Flexible DER.

[32] See the AER staff guidance on our Network Tariff Reform webpage.

[33] We define ‘medium business tariffs’ to be those applicable to customers that exceed the annual consumption limit for small business customers, but do not meet the minimum annual consumption required for assignment to a large business tariff.

We consider that the medium and large business tariffs proposed by the Victorian distributors strike a reasonable balance between being understandable and providing price signals to customers. However, there are several areas of concern for us in which we require greater clarity or amendments in the Victorian distributors' revised proposals. These areas are:

- tariff design and charging parameters
- optionality for medium and large business tariffs
- tariff treatment of grid-scale batteries
- tariff treatment of embedded networks.

We discuss each of these elements in detail below.

Tariff design and charging parameters

We are satisfied with the following charging parameters proposed by the five Victorian distributors for their medium, large, and sub-transmission class tariffs:

- annual consumption bands used to determine tariff class assignment
- demand capacity requirement thresholds used to determine tariff class assignment
- default tariff charging structures (i.e. flat rate, time-of-use, demand charge, critical peak pricing, etc.).

Other distributors across the NEM currently assign business customers to a tariff class using annual consumption bands[34] and/or demand capacity requirement thresholds.[35] As such, the Victorian distributors' proposals to use these parameters for assignment allow for consistency across the NEM for business customers. The default tariff structures proposed by the Victorian distributors are also similar to those used by other distributors in the NEM and indeed distributors internationally, further adding to consistency for customers.

Although we are satisfied with annual consumption bands being used to determine tariff class assignment, the bands proposed by the distributors vary considerably. The proposed consumption bands are shown in Table 19.2 below.

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34 Ausgrid, Essential Energy, and South Australian Power Networks, for example.

35 Energex, Ergon Energy, and TasNetworks, for example.

Table 19.2 Annual consumption bands for medium and large business tariffs proposed by Victorian distributors

Distributor	Medium business annual consumption band	Large business annual consumption band
AusNet Services	160 MWh to 400 MWh	>400 MWh
Jemena	40 MWh to 400 MWh	>400 MWh
CitiPower	60 MWh to 160 MWH	>160 MWh
Powercor	60 MWh to 160 MWH	>160 MWh
United Energy	40 MWh to 400 MWh	>400 MWh

Source: AER analysis of data provided by distribution businesses.

We hold some concerns that the inconsistency in annual consumption bands, and therefore tariff assignment, across the Victorian distributors may be difficult for customers to understand. However, we are satisfied that this risk is minimal due to the distributors making no changes to the existing annual consumption bands in their proposals.

Some stakeholder submissions received in response to the Victorian distributors' proposals raised concerns that demand capacity requirement thresholds and charges may act as a barrier to the rollout of electric vehicle public charging stations, as these costs are prohibitive while utilisation of public charging stations is still low.[36] We are in agreement that tariffs need to be designed in a way that does not prohibit rollout of electric vehicle charging stations. However, we view the demand capacity requirement thresholds as a suitable means to reflect the distributors' costs for providing the required capacity to large business customers, including electric vehicle charging station operators.

We require revisions to peak charging windows, or evidence to support those currently proposed

The NER require distortions to price signals for the efficient use of the Victorian distribution networks to be minimised.[37] We are not convinced that some of the proposed peak charging windows adhere to this requirement.

Proposed peak charging windows that are of particular concern to us are set out in Table 19.3 below.

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36 Electric Vehicle Council, *Submission on Victorian Electricity Revenue Proposals 2021–26*, June 2020, p.2; Evie Networks, *AER issues paper – Victorian electricity determination 2021–26: electricity tariff structures*, 3 June 2020, p.2.

37 NER cl. 6.18.5 (g).

Table 19.3 Peak charging windows of concern to us

Distributor	Tariff/s	Proposed peak charging window/s
AusNet Services	Default medium business tariff	07:00 to 10:00 16:00 to 23:00
Jemena	All medium business, large business and sub-transmission tariffs	07:00 to 23:00
CitiPower	Opt-in medium business tariff	07:00 to 23:00
United Energy	Opt-in medium business tariff	09:00 to 21:00

Source: AER analysis of data provided by distribution businesses.

We are concerned that the proposed peak charging windows listed in Table 19.3 may not accurately reflect when the network is under its greatest strain and may be too wide to send effective price signals to customers about their impact on the network. We require AusNet Services, Jemena, CitiPower and United Energy to address these concerns in their revised proposals. This may be either through proposing narrower peak charging windows (with supporting analysis) or providing analysis that supports the distributor's original proposal.

The Consumer Challenge Panel, sub-panel 17's (CCP17) submission supported the AER exploring whether peak network constraints and proposed charging windows align, but noted there can be merit in having common charging windows across distributors for simplicity.[38] Red Energy and Lumo Energy also argued that there is merit in setting common charging windows across distributors, even where peak periods are not aligned.[39] We agree that setting common charging windows across distributors can be beneficial, but we remain concerned that common charging windows may distort price signals too much for some distributors.

We seek clarity on how Powercor's charging windows reflect its network utilisation

Under the NER, distributor costs associated with meeting periods of highest network utilisation must be reflected in proposed tariffs.[40] Powercor proposed the same flat rate tariff with a seasonal demand charge for its medium business customers as CitiPower. Powercor also proposed the same peak and demand charge windows for its large business and sub-transmission tariffs.

Similarity in tariffs across distributors may assist with understandability for customers. However, customers assigned to medium business, large business, and sub-transmission tariffs are typically well engaged with network charges and have a good understanding of them. As such, we are more concerned that Powercor's

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[38] CCP17, *Advice to the AER on the Victorian Electricity Distributors' Regulatory Proposals for the Regulatory Determination 2021–26*, 10 June 2020, p.5.

[39] Red Energy and Lumo Energy, *Issues Paper – Victorian electricity distribution determination, 2021 to 2026*, 19 June 2020, p.3.

[40] NER, cl. 6.18.5 (f)

proposed peak and demand charging windows may not accurately reflect the periods where Powercor's network is most heavily utilised.

We have undertaken high-level analysis of substation demand peaks in Powercor's network. These peaks are broadly spread across the day and numerous substations incur their maximum demand outside the proposed peak and demand charging windows. This suggests the proposed charging windows may not sufficiently contribute to covering costs of these peak demand times.

We require Powercor to provide analysis that supports its proposed charging windows for its medium business, large business and sub-transmission tariffs. This means Powercor should provide data that demonstrates how these proposed charging windows reflect the recovery of costs associated with peak network demand. We would prefer data that can be made public, but will accept confidential data from Powercor to address this concern if needs be.

Powercor may wish to explore whether an alternative demand charge (e.g. without a time constraint) or critical peak pricing mechanism would be appropriate for Powercor's revised proposal.

We require United Energy to exclude or amend its opt-out flat tariff for medium businesses

United Energy proposed two alternative medium business tariffs: a time-of-use tariff and a flat tariff. Neither tariff includes a demand charge component. We do not accept the availability of a flat tariff option that does not contain a demand charge component for medium sized businesses.

We are satisfied with United Energy's proposed opt-out medium business time-of-use tariff without a demand charge component. This is because the peak and off-peak pricing structure provides some price signals to customers about their impact on the network. However, the opt-out medium business flat tariff proposed by United Energy does not provide any price signals to customers.

The CCP17 argued in its submission that a badly designed non-flat tariff may not be more cost-reflective than a flat tariff.[41] However, DELWP submitted that flat tariffs are no longer a fair or effective way to recover electricity provision costs.[42] We do not think that CCP17's argument is applicable here, because there are no cost-reflective elements to the proposed flat tariff. However, we think that flat tariffs can be effective in recovering electricity provision costs, if they are coupled with a cost-reflective element such as a demand or critical peak pricing charge.

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[41] CCP17, *Advice to the AER on the Victorian Electricity Distributors' Regulatory Proposals for the Regulatory Determination 2021–26*, 10 June 2020, p.143.

[42] Victorian Department of the Environment, Land, Water and Planning, *Victorian Government submission on tariff structure statements 2021–26*, 29 May 2020, p.1.

We are of the view that the standard, flat tariff proposed by United Energy is not suitable, particularly given the proposed availability of the opt-out medium business time-of-use tariff. We therefore require United Energy to amend its proposal for this tariff. United Energy must either add a demand charge or similar mechanism to provide price signals to customers. Or, United Energy must exclude its opt-out flat tariff from its revised proposal.

Optionality for medium and large business tariffs

The Victorian distributors assign their large customers to default tariffs that include cost reflective components, such as time of use charges and demand charges.[43] However, they provide no other options to larger customers besides these default tariffs. These customers include all customers in the high voltage (HV) and sub-transmission tariff classes, as well as the larger customers connected to the low voltage (LV) network. Table 19.4 below shows larger LV connected customers—that is, the tariff classes—who do not have access to alternative tariffs, including the size thresholds for these tariff classes.

In contrast, distributors in other jurisdictions generally offer large customers alternative cost reflective tariffs besides the default tariff.

Table 19.4 Victorian medium and large customers in the LV network with no alternative network tariffs

Distributor	LV tariff class	Threshold (MWh)	Threshold (kVA)
CitiPower, Powercor	Large Low voltage	>160	>120
United Energy	Large Low voltage	>400	>150
Jemena	Large business LV	>400	>120
AusNet Services	Medium industrial and commercial	>160 <400	NA
	Large industrial and commercial	>400	NA

Source: CitiPower, *APP06: Tariff structure statement technical*, 31 January 2020, pp. 10–12; Powercor, *APP06: Tariff structure statement technical*, 31 January 2020, pp. 11–13, United Energy, *APP06: Tariff structure statement technical*, 31 January 2020, pp. 10–12; Jemena, *Att 08-01: Tariff structure statement for 1 July 2021 to 30 June 2026*, 31 January 2020, pp. 13–16; AusNet Services, *Tariff structure statement 2022–26: Compliance document*, 31 January 2020, pp. 11–13.

43 United Energy, AusNet Services and Jemena define large customers as those with annual consumption greater than 400MWh per annum. CitiPower and Powercor define large customers as those with annual consumption greater than 160MWh per annum.

For their revised proposals, we require the Victorian distributors to provide alternative cost reflective tariffs to their medium and large business tariffs, specifically:

- an alternative general tariff for medium business customers (this applies particularly to AusNet Services)
- ICC tariffs for large business customers.

We discuss these requirements for greater optionality below.

Alternative network tariff for medium business customers (AusNet Services)

We require AusNet Services to offer its medium business customers an alternative network tariff to its default tariff.[44]

AusNet Services offers only one network tariff to its medium business customers, with the majority of such customers assigned to a critical peak demand tariff.[45] This is in contrast to other distributors (in Victoria and other jurisdictions) who offer medium business customers alternative cost reflective tariffs besides the default tariff. By offering an alternative tariff, AusNet Services can ascertain customer responsiveness to different types of price signals. Such learnings could assist in furthering the cost reflectivity of medium business tariffs in future regulatory control periods.

On the other hand, we commend AusNet Services for developing and offering its critical peak demand tariff. We consider these tariffs are amongst the most cost reflective distribution network tariffs in the NEM. This is especially the case for medium-sized businesses connected to distributors' low voltage networks.

We therefore do not consider the alternative network tariffs for AusNet Services' medium business customers necessarily require a radical departure from the default critical peak demand tariffs.

For example, an alternative tariff can keep the basic structure of the default critical peak demand tariff but calculate the critical peak demand charge based on the average of the top two (rather than five) recorded demand events. Such sharper price signals can be offset with a lower fixed charge, thereby providing customers with greater scope to mitigate tariff impacts through their usage decisions.[46]

Of course, AusNet Services may opt to offer an alternative cost reflective tariff that represents a more significant step towards cost reflectivity, if it considers it appropriate to do so. AusNet Services may increase the dynamic characteristics of the critical peak demand tariffs, for example. The default critical peak demand tariffs charge is based

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[44] AusNet Services defines medium business customers as those who consume between 160 and 400 MWh per annum.

[45] Medium and large business customers on legacy tariffs (those that are closed to new customers) are able to move to a critical peak demand tariff, based on annual consumption. AusNet Services, *Tariff Structure Statement 2022–26: Explanatory paper*, 31 January 2020, pp. 11 and 52.

[46] NER, cl. 6.18.5(h)(3).

on the average of five recorded peak demand events between 3pm and 7pm on five days nominated in advance.[47] An alternative tariff may leave open the hours of the day in which the critical peak demand charging parameter applies. This would better target critical peak demand events where they fall outside of the fixed 3pm and 7pm window.

ICC tariffs for large business customers

We require the Victorian distributors to 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. We also require the Victorian distributors to set out the parameters and processes they would use to develop the charging parameters and price levels of ICC tariffs.

As noted in Table 19.4 the Victorian distributors offer only one network tariff to their large business customers. This is in contrast to distributors in other jurisdictions, who generally offer large business customers other cost reflective tariffs in addition to the default tariff.

As the name suggests, the charging parameters and particularly the price levels of ICC tariffs are unique to each recipient and so can be highly cost reflective. They are intended to signal the costs of providing network services to specific sites on a distributor's network. ICC tariffs should therefore have a strong LRMC basis (which we discuss in more detail in section 19.4.3).[48] Where price levels diverge significantly from LRMC, distributors should provide reasons.

We consider ICC tariffs provide a good opportunity to expose the Victorian distributors, customers, and stakeholders to highly cost reflective concepts such as locational price signals and seasonality. It can also be a good vehicle to introduce more dynamic charging parameters (similar to the discussion in the "Medium business customers" section above). By offering ICC tariffs, the Victorian distributors can also ascertain customer responsiveness to different types of price signals. Such learning could assist in furthering the cost reflectivity of the generally available large business tariffs. Such initiatives in turn could pave the way for greater tariff reform for other customers in future regulatory control periods.

We note the discussion above implies developing highly cost reflective ICC tariffs at the level of distribution network tariffs (also referred to as DUOS).[49] One idea we would like to put forward for consideration is that ICC tariffs can be in the form of a direct pass through of the locational component of transmission network tariffs (also referred to as TUOS).[50] This can be in addition to, or in place of, a locational DUOS price.

The NER require transmission networks to set prices that reflect costs specific to each transmission connection point (in addition to postage stamp prices).

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[47] AusNet Services, *Tariff Structure Statement 2022–26: Compliance document*, 31 January 2020, pp. 11–12.

[48] NER, cl. 6.18.5(f).

[49] DUOS, or distribution use of system, tariffs signal the costs of the electricity distributor.

[50] TUOS, or transmission use of system, tariffs signal the costs of the electricity transmission business.

However, distributors generally do not maintain those locational signals when setting their total network prices.[51] Passing through the locational TUOS price via ICC tariffs can be a good way to begin incorporating locational signals into total network tariffs. Passing through the locational TUOS charge via the ICC may be a less resource intensive option for the Victorian distributors to introduce site-specific tariffs at this stage given they are already a requirement in transmission pricing.

Tariff treatment of grid-scale batteries

We have not yet made a decision regarding the distributors' proposed approach to grid-scale batteries under the proposed tariff structure statements. This is an emerging issue on which we seek stakeholder submissions during the post-draft decision consultation phase.

Grid-scale batteries are an emerging issue

Grid-scale batteries have the potential to enable distributors to better manage demand on their networks. They may also be useful in new business models, such as virtual power plants, or when combined with large scale intermittent renewable energy generation. However, grid-scale batteries are in early stages of development and usage by the Victorian distributors. There are currently six batteries across the five networks – three are being used for network support services while the other three are currently being operated under trials.

Furthermore, there were very few mentions of grid-scale batteries/storage in stakeholder submissions received in response to the Victorian distributor proposals. The CCP17 was the only stakeholder to mention batteries and storage, although this was just to note the absence of any detailed analysis or commentary in the proposals.[52]

Proposed tariff treatment of grid-scale batteries is inconsistent across the distributors

All five Victorian distributors proposed that any battery owned by them be exempt from network tariffs. However, proposed tariff treatment differs for batteries not owned by the distributor.

CitiPower, Powercor and United Energy proposed to exempt grid-scale batteries they do not own from a network tariff under some circumstances, upon which they would enter into a contract with the battery owner. A contract may be entered into where there is only generation or no other load at the site (other than that associated with the

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51 Here, total network tariffs represent the sum of TUOS, DUOS and jurisdictional obligations such as feed-in tariffs. They are generally referred to as NUOS, or network use of system, tariffs and they are the tariffs electricity distributors charge their customers (generally electricity retailers).

52 CCP17, *Advice to the AER on the Victorian Electricity Distributors' Regulatory Proposals for the Regulatory Determination 2021–26*, 10 June 2020, p.80.

battery) or where the contract provides assurances that the battery will be operated 'to the net benefit' of the distributor's customers.

AusNet Services and Jemena proposed to continue to treat grid-scale batteries in accordance with their demands on the network, with no exemptions to tariffs. However, Jemena is considering a tariff specific to customers that provide network benefits, including battery owners.[53]

The NER are currently unclear on tariff treatment of grid-scale batteries

The NER do not currently recognise grid-scale batteries, or indeed any energy storage system. This means that grid-scale batteries must be registered as a market customer and market generator (i.e. they are treated as both load drawing and load generating). As such, tariff treatment of grid-scale batteries varies across the NEM, because each distributor must determine whether it must recover network charges from grid-scale batteries to comply with the NER.[54]

Tariffs applied to grid-scale batteries for the load they draw from the network can also create perverse charging incentives for the battery. This issue was noted by Edify Energy (a renewable energy development and storage investment company) in its knowledge-sharing report on the Gannawarra Energy Storage System (GESS) project, which is a grid-scale battery connected to Powercor's network. Edify Energy argued that the application of network tariffs placed a commercial incentive on the GESS to charge from the connected Gannawarra Solar Farm during the day, when demand on the network is highest, rather than charge from the network overnight when demand would be expected to be significantly lower, to avoid incurring tariff charges.[55]

Our view on options for tariff treatment of grid-scale batteries in Victoria

We have not yet made a decision on tariff treatment of grid-scale batteries, given the limited information provided by the Victorian distributors in their proposals and the lack of stakeholder comments on the issue. We also note that the AEMC is currently reviewing the Australian Energy Market Operator's (AEMO) Integrating Energy Storage rule change proposal - discussed in further detail below.

We consider there to be four options available to us in this area, namely:

1. Accept the Victorian distributors' proposed treatment of grid-scale batteries.
2. Require AusNet Services and Jemena to offer similar network tariff exemptions to those proposed by CitiPower, Powercor, and United Energy.
3. Require all Victorian distributors to exempt grid-scale batteries from the residual component of network tariffs.

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53 Jemena, *Tariff structure statement – explanatory document*, pp.56-57.

54 AEMO, *Electricity rule change proposal – integrating energy storage systems into the NEM,* p.20.

55 Edify Energy, *Gannawarra Energy Storage System – Project Summary Report*, p.16.

4. Require all distributors to exempt grid-scale batteries from network tariffs if the battery is registered as a scheduled load.

The above options concerning exempting grid-scale batteries from network tariffs refer to exempting them from the ongoing distribution use-of-system (DUOS) charges. We are not considering any changes in the calculation of upfront connection charges, because connection charges are not part of the tariff structure statement (TSS).

Option 1: Accept the Victorian distributors' proposed treatment of grid-scale batteries

This option would limit changes required of the Victorian distributors to only those (if any) required under the AEMC Integrating storage into the NEM rule change process. However, we hold concerns regarding the differences in proposed treatment of grid-scale batteries across the Victorian distributors, both during the rule change process and potentially longer term if no changes are made to the NER.

These differences may lead to development and uptake of grid-scale batteries accelerating in the CitiPower, Powercor and United Energy networks, but being limited in the AusNet Services and Jemena networks. Different treatment across the Victorian distributors – particularly differences as stark as being exempt or facing a full network tariff – is likely to be distortionary and not lead to battery development in the most efficient locations.

Option 2: Require AusNet Services and Jemena to offer similar network tariff exemptions to those proposed by CitiPower, Powercor and United Energy.

Under this option, we would require AusNet Services and Jemena to also offer exemptions to network tariffs for grid-scale batteries, adopting the same criteria as proposed by CitiPower, Powercor, and United Energy. This option would create consistency in tariff treatment of grid-scale batteries in Victoria. It should also encourage increased trials and uptake of grid-scale batteries. This may become increasingly important over time, given the significant increases in solar PV penetration and other variable renewable generation that have been forecast for Victoria.

However, this option means that no grid-scale batteries in Victoria with an exemption would be receiving price signals for their operation and usage. It is also currently unclear how the distributors would interpret and enforce the contractual requirements around the battery being operated 'to the net benefit' of the distributor's customers.

Option 3: Require all Victorian distributors to exempt grid-scale batteries from the residual component only of network tariffs.

This option would require grid-scale batteries to be treated in a similar way to other generation-only technologies (i.e. those that do not draw load from the network). In the NEM, generation only-technologies do not generally contribute to the recovery of a distributor's residual costs. This is because most generation has non-firm access to the network and only exports to the grid if it is dispatched by the market operator.[56] Conversely, load technologies, including grid-scale batteries, have firm access to the network so they can draw from the grid when needed. They therefore pay residual costs.

Grid-scale batteries can have many uses, including as an alternative source of generation (standalone battery) or to make variable renewable energy more dispatchable (co-located with generation such as solar PV). However, because batteries also draw load from the network they typically need to pay residual costs. This creates a distortion in business models, because an alternative load-only technology that performs a similar function to a dispatching grid-scale battery (such as a gas peaking plant) is not subject to the same costs. This may conflict with one of the pricing principles for direct control services, which requires distortions in the recovery of residual costs to be minimised.[57] As such, it may be appropriate to exempt grid-scale batteries from paying the residual cost component of DUOS charges.

Although an exemption for residual costs may be appropriate, it may not be appropriate to exempt grid-scale batteries from the LRMC cost component of DUOS charges paid. These charges may be useful in sending price signals to grid-scale batteries about the impact the battery has on the distributor's network and provide an important incentive for grid-scale batteries to be charged during off-peak periods.

A significant practical challenge with this approach is that distributors do not often clearly distinguish between those charging parameters that signal LRMC and those charging parameters that recover residual costs. This is particularly the case with large user network tariffs, where capacity charges and sometimes demand charges may be intended to both signal LRMC and achieve residual cost recovery.

Option 4: Require all distributors to exempt grid-scale batteries from network tariffs if the battery is registered as a scheduled load.

Under this option we would require distributors to exempt grid-scale batteries that are registered as a scheduled load from network tariffs. Being registered as a scheduled load would give the grid-scale battery non-firm access to the network as the distributor would be able to 'constrain off' the battery when the network does not have sufficient capacity for the battery to charge (e.g. during peak periods). In this scenario, reliability standards would not drive network investment related to grid-scale batteries – only economic assessments would. This means that a grid-scale battery would only drive network augmentation if there is a net benefit to the network. As such, the grid-scale battery would effectively be operating as part of the network, and would therefore not need to contribute to the recovery of network costs.

56 To be dispatched, the generation must be the lowest cost generation source at the time to meet demand, taking into account network constraints.

57 NER cl. 6.18.5 (g).

Any other grid-scale batteries (i.e. that are not registered as a scheduled load) would continue to face the same network tariffs as any other load connection of similar size.

This option is somewhat similar to the second option presented above (i.e. where all distributors exempt grid-scale batteries from network tariffs if they operate to a net benefit of the network). However, this option would stipulate the way in which a grid-scale battery would operate 'to the net benefit' of the distributor's customers, rather than leaving this criteria open for distributors to determine.

AEMC Integrating storage into the NEM rule change proposal review

Any decision that we make, in respect of when tariffs will be applicable to storage, as part of the Victorian electricity distribution determination is likely to be superseded by the outcome of the AEMC's current Integrating storage into the NEM rule change proposal review.

In August 2019, AEMO submitted a rule change request to the AEMC relating to integrating energy storage systems into the NEM.[58] Among other issued raised, AEMO argued there is a need for the NER to clarify whether DUOS and TUOS charges should apply to energy storage systems (including grid-scale batteries). AEMO argued that current ambiguity in the NER means the rules are interpreted and implemented differently for each energy storage system. This has created perverse incentives in the NEM, both in terms of where energy storage systems are located and when the systems are charged (i.e. they may be charged to avoid network charges rather than when would be most efficient for the storage system/network). This latter point was also raised by Edify in its GESS project summary report (see above).

The AEMC commenced a review of this rule change proposal in August 2020. This review will examine the significance of the issues raised by AEMO and whether a new participant category should be established. The AEMC review will also interact with the ESB's post-2025 market design program, which includes a work stream relating to a potential two-sided energy market.

Given the complexity of the rule change proposal and review process that the AEMC is undertaking, it is highly unlikely the process will be finalised prior to our final decision on the Victorian distributor proposals in April 2021. As a result, any decision we make regarding tariff treatment of grid-scale batteries in Victoria may be an interim arrangement until any outcome of the AEMC process is determined and implemented.

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58 Available at: https://aemo.com.au/-/media/files/electricity/nem/initiatives/emerging-generation/23-august-2019--integrating-ess-rule-change-proposal-final.pdf?la=en&hash=F500525F8539D6BA070629AA3E0ACEDD

We seek stakeholder submissions on tariff treatment of grid-scale batteries during our post-draft decision consultation phase

Given the broad range of issues and considerations outlined above, we seek submissions from the Victorian distributors and other stakeholders on tariff treatment of grid-scale batteries. In particular, we seek stakeholder views on whether:

- Stakeholders have a preference for any of the four options highlighted, or if there are any additional options that should be considered.
- There are any significant benefits given and/or disincentives caused to grid-scale battery operators, or other affected parties, by the distributors' proposed tariff treatment of grid-scale batteries.
- There are any significant benefits given and/or disincentives caused to grid-scale battery operators, or other affected parties, under the options we have put forward.
- The AEMO rule change proposal and/or the AEMC's process may impact grid-scale battery development and/or adoption in the future.

Tariff treatment of embedded networks

Our draft decision is to accept the Victorian distributors' proposed tariff treatment of embedded networks.

Jemena is the only distributor to have proposed assigning embedded networks to a specific tariff. AusNet Services proposed tariffs specific to embedded networks, but these are to be used as a point of comparison for embedded network customers (i.e. no customers will be assigned to these tariffs). CitiPower, Powercor, and United Energy proposed to assign embedded networks to large business tariffs based on their connection and usage characteristics.

These differences in proposals are of some concern to us, in that similar customers may be charged quite differently based on which network they are connected to. However, multiple reviews undertaken in Victoria, both currently and recently completed, alleviate these concerns.

DELWP is currently in the early stages of conducting an Embedded Networks Review. This review was a commitment by the Victorian Government as part of its October 2018 election to ban embedded networks in new residential apartment buildings.[59] We anticipate that this will reduce the growth of embedded networks in Victoria and therefore limit the number of embedded network customers.

The Essential Services Commission (ESC) has also recently made a final decision on maximum electricity prices for embedded networks. From 1 September 2020, the maximum price for residential and small business customers within an embedded

[59] Exemptions will be available for buildings that use renewable energy micro-grids to deliver low-cost renewable energy.

network is to be set at the level of the VDO.[60] This provides price protection for these customers, which account for the majority of embedded network customers according to ESC.

Our concerns are further alleviated by Jemena's proposed treatment of embedded networks. Jemena, which is the only distributor that assigns customers to its embedded network tariffs, is not proposing any material changes in its embedded network tariff arrangements. We are therefore satisfied that there would be minimal customer impact in approving this element of Jemena's proposal.

Lastly, but importantly, tariff arrangements for embedded networks was not a focus of stakeholder submissions. The only indirect mention of embedded networks was made by the Electric Vehicle Council, noting that electric vehicle charging arrangements for residents in strata apartment blocks is likely to be an evolving area.[61] We agree that this is an emerging issue. However, it may be dealt with under other areas of network tariff reform such as those relating to electric vehicles.

19.4.3 Long run marginal cost methodology

An important feature of this draft decision is the concept of LRMC. LRMC is equivalent to the forward looking cost of a distributor providing one more unit of service, measured over a period of time sufficient for all factors of production to be varied.[62] LRMC could also be described as a distributor's forward looking costs that are responsive to changes in electricity demand.

The NER require network tariffs to be based on LRMC.[63] However, not all of a distributor's costs are forward looking and responsive to changes in electricity demand. If network tariffs only reflected LRMC, a distributor would not likely recover all its costs. Costs not covered by a distributor's LRMC are called 'residual costs'. The NER require network tariffs to recover residual costs in a way that minimises distortions to the price signals for efficient usage that would result from tariffs reflecting only LRMC.[64]

We consider the methods the Victorian distributors used to estimate LRMC contribute to compliance with the pricing principles for direct control services. At this stage, we consider the Victorian distributors have achieved an appropriate balance between the

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60 Essential Services Commission, *Maximum electricity prices for embedded networks and other exempt sellers review 2020*, available at: [https://www.esc.vic.gov.au/electricity-and-gas/prices-tariffs-and-benchmarks/embedded-network-tariffs-including-caravan-parks/maximum-electricity-prices-embedded-networks-and-other-exempt-sellers-review-2020.](https://www.esc.vic.gov.au/electricity-and-gas/prices-tariffs-and-benchmarks/embedded-network-tariffs-including-caravan-parks/maximum-electricity-prices-embedded-networks-and-other-exempt-sellers-review-2020)

61 Electric Vehicle Council, *Submission on Victorian Electricity Revenue Proposals 2021–26*, June 2020, p.1

62 NER, cl 10 Glossary defines long run marginal costs as the cost of an incremental change in demand for direct control services provided by a distribution network service provider over a period of time in which all factors of production required to provide those direct control services can be varied.

63 NER, cl. 6.18.5(f).

64 NER, cl. 6.18.5(g)(3).

benefits of using methods that better represent the concept of LRMC and the costs those measures impose (greater information and administrative requirements).[65]

We recognise the methods for estimating LRMC in the NEM are in a process of development and improvement. In the first TSS round, all distributors in the NEM used the Average Incremental Cost (AIC) approach to estimate LRMC. While at the time we accepted this approach, distributors were encouraged to continue to improve their estimation methods so that their tariffs better reflect efficient costs.[66]

As part of this second TSS round, several distributors have assessed the merits of alterative LRMC estimation methods.[67] In this context, we particularly commend CitiPower, Powercor, and United Energy.

As tariff reform progresses in future regulatory control periods, we encourage all stakeholders to give this matter further consideration.

Below we set out our assessment of the Victorian distributors' approaches to estimating LRMC regarding compliance with the pricing principles for direct control services. In doing so, we have had regard to the assessment framework we have used for this second round of tariff structure statements.[68]

19.4.3.1 Proposed estimation methods

CitiPower, Powercor, and United Energy

CitiPower, Powercor, and United Energy—through their consultant, ENEA—used the Marginal Incremental Cost (MIC) approach to estimate LRMC over a 10 year forecast period. We understand the MIC approach operates in principle like the Turvey approach in that its LRMC estimates represent the change in costs due to a shift in demand.[69]

CitiPower, Powercor, and United Energy stated that ENEA selected the MIC approach because it can cater for network areas with decreasing/flat demand and can be adapted to accommodate replacement costs.[70]

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65 NER, cl. 6.18.5(f).

66 The AIC was widely used as it had lower information requirements, though it is perceived as being less representative of 'marginal costs'. Other methods, particularly the Turvey method, are seen as more closely representing the marginal cost concept, but have greater information requirements.

67 These methods either made improvements to the application of the Average Incremental Cost approach, or explored more sophisticated estimation methods, such as the Turvey approach.

68 See appendix C in our previous distribution determinations as discussed in our website (https://www.aer.gov.au/networks-pipelines/network-tariff-reform).

69 CitiPower, *Attachment 025 - ENEA - Long run marginal cost report*, 31 January 2020, pp. 3–4 and 30–31; Powercor, *Attachment 025 - ENEA - Long run marginal cost report*, 31 January 2020, pp. 3–4 and 30–31; United Energy, *Attachment 025 - ENEA - Long run marginal cost report*, 31 January 2020, pp. 3–4 and 30–31.

70 CitiPower, *Tariff structure statement: CitiPower 2021–26*, 31 January 2020, p. 21; Powercor, *Tariff structure statement: Powercor 2021–26*, 31 January 2020, p. 22; United Energy, *Tariff structure statement: United Energy 2021–26*, 31 January 2020, p. 21.

Augmentation expenditure (augex) projects were the principal capital expenditure (capex) inputs into the LRMC calculations, although several replacement expenditure (repex) projects were used in the calculations for CitiPower and Powercor. ENEA stated it explicitly excluded repex projects in substations with less than 3 transformers, to avoid reducing security of supply.[71]

ENEA produced long run marginal costs for each zone substation of the respective CitiPower, Powercor, and United Energy networks and at different voltage levels.[72]

CitiPower, Powercor, and United Energy noted that since the low voltage network is planned in the short term only, there was no planning data for the low voltage network. ENEA used the average historic marginal cost of reinforcement of the low voltage network as a proxy for the low voltage LRMC in all zone substation supply areas.[73]

AusNet Services and Jemena

AusNet Services and Jemena used the AIC approach to estimate LRMC over a 10-year forecast period.[74] Both distributors produced LRMC estimates for their respective tariff classes.[75]

AusNet Services stated it adopted the AIC approach "for a number of reasons, including, but not limited to:

- AIC is commonly used by distribution networks, as it is generally considered to be well suited to situations where there is fairly consistent profile of investment over time to service growth in demand.
- AIC does not rely on a forecast of growth in the demand for AusNet Services' services that differs materially from the broader forecasts that underpin other components of AusNet Services' regulatory [proposal]."[76]

Jemena stated it does not consider the cost of using a more complex approach, such as the Turvey method, would provide additional benefits that would outweigh the use of

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71 CitiPower, *Attachment 025 - ENEA - Long run marginal cost report*, 31 January 2020, pp. 7–8; Powercor, *Attachment 025 - ENEA - Long run marginal cost report*, 31 January 2020, pp. 7–8; United Energy, *Attachment 025 - ENEA - Long run marginal cost report*, 31 January 2020, pp. 7–8.

72 CitiPower, *Tariff structure statement: CitiPower 2021–26*, 31 January 2020, p. 22–23; Powercor, *Tariff structure statement: Powercor 2021–26*, 31 January 2020, p. 23–24; United Energy, *Tariff structure statement: United Energy 2021–26*, 31 January 2020, p. 22–23.

73 CitiPower, *Tariff structure statement: CitiPower 2021–26*, 31 January 2020, p. 21; Powercor, *Tariff structure statement: Powercor 2021–26*, 31 January 2020, p. 22; United Energy, *Tariff structure statement: United Energy 2021–26*, 31 January 2020, p. 21.

74 AusNet Services, *Tariff Structure Statement 2022–26: Compliance document*, 31 January 2020, pp. 29 and 30; AusNet Services, *TSS - LRMC and Avoidable Cost Model*, 31 January 2020, 'LRMC by Voltage Region & Driver'!R21, R40 and R59; Jemena, *Att 08-01: Tariff structure statement for 1 July 2021 to 30 June 2026*, 31 January 2020, p. 19; Jemena, *Att 08-03: Long run marginal cost model*, 31 January 2020, 'LRMC estimation'!.

75 AusNet Services, *Tariff Structure Statement 2022–26: Compliance document*, 31 January 2020, p. 30; Jemena, *Att 08-01: Tariff structure statement for 1 July 2021 to 30 June 2026*, 31 January 2020, p. 20.

76 AusNet Services, *Tariff Structure Statement 2022–26: Compliance document*, 31 January 2020, p. 29.

the AIC approach. Jemena further stated the AIC approach has been widely used and accepted by the AER as a reasonable estimate for tariff setting purposes.[77]

AusNet Services' and Jemena's primary inputs into their LRMC calculations are forecast augex and associated opex, as well as forecast demand.[78]

AusNet Services explicitly excluded forecast replacement capex.[79] It stated it does not expect forecast changes in demand or consumption to materially affect the timing and scale of these costs. Rather, condition and risk factors unrelated to loads on assets are the predominant drivers of replacement capex.[80]

Jemena also did not include repex into its LRMC calculations, but did not appear to provide reasons for this exclusion.[81]

19.4.3.2 Assessment of LRMC approach

We are satisfied that the Victorian distributors' approach to estimating LRMC contributes to the achievement of compliance with the pricing principles for direct control services or to the achievement of the network pricing objective. As we discuss below, however, we encourage AusNet Services and Jemena to review whether they can include replacement capital expenditure (repex) in their LRMC calculations for their revised proposals.

Incorporation of repex into LRMC

We consider CitiPower, Powercor, and United Energy's approach to incorporating repex into its LRMC estimates contributes to compliance with the pricing principles for direct control services or to the achievement of the network pricing objective. Their consultant (ENEA) included repex projects for parts of the network with an expected reduction in load. That is, the LRMC estimates for such locations represent avoided repex per unit of reduced demand.[82] We consider this is consistent with the definition of LRMC[83]

We encourage AusNet Services and Jemena to continue exploring ways to incorporate repex into their LRMC method for its revised proposal. We consider there are two potential areas for exploration.

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77 Jemena, *Att 08-01: Tariff structure statement for 1 July 2021 to 30 June 2026*, 31 January 2020, p. 19.

78 AusNet Services, *Tariff Structure Statement 2022–26: Explanatory paper*, 31 January 2020, pp. 53–54; AusNet Services, *TSS - LRMC and Avoidable Cost Model*, 31 January 2020, 'Input Sheet - LRMC'!; Jemena, *Att 08-03: Long run marginal cost model*, 31 January 2020, 'LRMC estimation'! and 'Capex calculations'!.

79 AusNet Services excluded costs for which it considers forecast changes in demand or consumption are not drivers. These include forecast replacement capex (repex), forecast DER integration capex (which is a component of augex) and sunk costs. AusNet Services, *Tariff Structure Statement 2022–26: Explanatory paper*, 31 January 2020, p. 54; AusNet Services, *TSS - LRMC and Avoidable Cost Model*, 31 January 2020, 'Rin Template'!B15.

80 AusNet Services, *Tariff Structure Statement 2022–26: Explanatory paper*, 31 January 2020, p. 54.

81 Jemena, *Att 08-03: Long run marginal cost model*, 31 January 2020, 'LRMC estimation'! and 'Capex calculations'!.

82 ENEA, p. 11.

83 NER, chapter 10.

AusNet Services and Jemena should investigate whether there is potential to avoid repex in areas where demand is forecast to decrease.[84] As noted in our previous distribution determinations:[85]

> When assets come to the end of their useful life, distributors have a choice of maintaining their current level of capacity, increasing capacity or decreasing capacity, depending on demand and use of the network. Distributors should not adopt a default position of maintaining existing capacity levels, especially where existing networks have spare capacity and where there are changing patterns of use.

AusNet Services and Jemena can explore whether any repex required for these substations involves a reduction in capacity levels. They can then produce estimates of LRMC that represent the decline in forecasts costs in areas of declining demand.[86] This is similar to Endeavour Energy's LRMC estimation method.[87]

Alternatively, AusNet Services and Jemena can explore the ECA's and Energeia's suggestion for incorporating repex into LRMC estimates. The ECA (with their consultant, Energeia) suggested the Victorian distributors offer an optional cost reflective tariff that would facilitate the uptake of EVs. Such a tariff would send sharper price signals only at the times of the year in which peak demand could trigger future investment.[88]

Energeia’s report appears to suggest that distributors should be looking at the time horizon in which all costs are variable.[89] In discussions between AER staff and ECA/Energeia, Energeia clarified its view that there is a greater risk of grid defection in the long run. Hence, LRMC estimates should include a higher contribution from repex because all repex are potentially avoidable in the future.

We acknowledge this view of the “long run” is consistent with the definition of ‘long run marginal cost’ in the NER.[90]

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84 For example, there are several substations for which AusNet Services forecasts reductions in demand over the forecast horizon. AusNet Services, *TSS - LRMC and Avoidable Cost Model*, 31 January 2020, 'raw Demand Forecast'!.

85 AER, *Draft decision: SA Power Networks distribution determination 2020 to 2025: Attachment 18: Tariff structure statement*, October 2019, p. 33.

86 “Marginal cost” is often discussed in terms of “increments”: that is, the additional costs due to additional demand for the network. However, it can also be seen in the other direction: that is, the costs avoided due to decreases in demand.

87 See AER, *Draft decision: Endeavour Energy distribution determination 2019 to 2024: Attachment 18: Tariff structure statement*, November 2018, pp. 24–28.

88 While ECA/Energeia explicitly note that such an optional tariff would facilitate EV take-up, their submission does not appear to be suggesting an “EV tariff” available to EV owners only. Their analysis is based on general network congestion rather than network conditions specifically caused by EVs. They also note their proposed tariff design would leave customers without solar PV or EVs “no worse off than average”.

89 Energeia, *‘Prices-to -Devices’ Tariffs: Developing a more cost reflective EV Tariff for Victoria: Energy Consumers Australia*, 5 June 2020 pp. 2–3.

90 NER, chapter 10.

We understand Energeia considered two aspects of LRMC estimates: one driven by augex and another by repex. This is similar to Endeavour Energy's approach which produced two sets of LRMC estimates, as noted previously. The first, augex-driven LRMC estimates, measure increases in forecast expenditure due to increments in demand. Meanwhile, repex-driven LRMC estimates measure avoided forecast expenditure due to decrements in demand.

The difference is Endeavour Energy explicitly assessed which of its repex projects within the 10-year forecast horizon can be avoided, and hence is suitable for inclusion into the LRMC calculation.[91]

On the other hand, ECA/Energeia assume a high percentage (up to 100 per cent) of repex—as well as connections capex (connex)—is avoidable in the long run due to the potential for grid defection. Based on this analysis, Energeia produced alternative LRMC estimates that incorporated 100 per cent of the repex and connex in the Victorian distributors' proposals. The resulting LRMC estimates are significantly higher than those the Victorian distributors proposed: from two times higher in the case of CitiPower, to six times higher in the case of AusNet Services.[92]

Energeia also produced LRMC estimates that incorporated 50 per cent of the repex included in the Victorian distributors' 10-year forecast horizon. These LRMC estimates are still higher than the Victorian distributors' estimates but to a lesser extent: from near parity for CitiPower to being three times higher for AusNet Services.

Energeia recommended using the assumption that 50 per cent of repex is avoidable when calculating LRMC (and designing and setting tariffs).[93]

We consider Energeia's proposed method for incorporating repex inputs into LRMC calculations could be an innovative way to balance two competing factors:

- the requirement to consider costs and demand in the long run
- the increasing uncertainty in forecasting such costs and demand conditions over longer time horizons.

We encourage AusNet Services and Jemena to consider Energeia's approach to incorporating repex within its LRMC calculations. However, we do not require either distributor to adopt Energeia's proposed approach at this stage. We consider this approach needs greater deliberation before making it a requirement for the Victorian distributors in the 2021–26 regulatory control period.

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91 See AER, *Draft decision: Endeavour Energy distribution determination 2019 to 2024: Attachment 18: Tariff structure statement*, November 2018, pp. 24–28.

92 Energeia, *'Prices-to -Devices' Tariffs: Developing a more cost reflective EV Tariff for Victoria: Energy Consumers Australia*, 5 June 2020 p. 28.

93 Energeia, *'Prices-to -Devices' Tariffs: Developing a more cost reflective EV Tariff for Victoria: Energy Consumers Australia*, 5 June 2020 p. 28.

Below, we discuss several issues for consideration should AusNet Services and Jemena look at adopting Energeia's approach in the revised proposal (or future regulatory control periods).

Given sufficient advances in technology (and its proliferation), it is conceivable there would be risk of grid defection in all parts of a distributor’s network. All future repex can be demand sensitive under such conditions. The issues arise in applying the ECA/Energeia approach in the transition to such a state.

There is considerable uncertainty regarding the pace of technological progress and proliferation and therefore when in the long run grid defection becomes a real risk.

It is possible ECA/Energeia attempted to account for such uncertainty by suggesting inclusion of 50 per cent of forecast repex, rather than 100 per cent, in the LRMC estimates for the 2021–26 control period. However, they did not elaborate on the basis of the 50 per cent figure. It could be argued that a lower percentage (say, 10 per cent) is appropriate under current conditions - distribution networks generally have relatively few constraints.[94] This percentage can then increase in future regulatory control periods as the risk of grid defection increases due to technological advances and proliferation. This is analogous to applying a very low LRMC value to an unconstrained part of the network, albeit with growing demand. This is because incremental demand does not impose additional cost on the network under such conditions. The LRMC signal would increase in future periods as demand grows and the network progressively becomes constrained.

Another potential issue concerns the application of the Energeia approach. We understand the ECA/Energeia submission proposes this approach of significantly increasing repex in the LRMC calculations only for their suggested voluntary tariffs for EVs. We understand the LRMC calculations for other tariffs would continue to use the Victorian distributors' respective estimation methods.

It can be appropriate to utilise different calculation methods for different situations. For example, the AEMC considered it may be appropriate to use the Turvey method in a targeted fashion. A distributor may use the Turvey method to estimate LRMC for those constrained parts of the network where investment is being contemplated. In those cases, the benefits of calculating (and sending) a more accurate signal of LRMC may outweigh the costs. For the remainder of the network, the AEMC considered it is sufficient to use simpler methods such as the AIC method.[95]

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94 Energeia investigated the effect of including 12 per cent of repex in LRMC calculations. Energeia’s LRMC figures do not differ significantly to Powercor’s and United Energy’s LRMC estimates, and is even 30 per cent lower than CitiPower’s LRMC estimate. However, the Energeia estimates were about 65 per cent higher than Jemena’s and AusNet Services’ respective LRMC estimates. Energeia, *‘Prices-to -Devices’ Tariffs: Developing a more cost reflective EV Tariff for Victoria: Energy Consumers Australia*, 5 June 2020 p. 27.

95 AEMC, *Rule determination: National Electricity Amendment (Distribution Network Pricing Arrangements) Rule 2014*, 27 November 2014, pp. 128–129.

However, we do not consider ECA/Energeia's proposal of using their LRMC approach exclusively for their proposed EV tariff to be appropriate. We consider distributors should calculate a single LRMC that they consider best signals the costs each customer's usage imposes on the network having regard to the cost and benefits of such a calculation.[96] This would make the distributor's tariff setting method more transparent, particularly where the tariffs available to that customer deviate from the LRMC estimate.

Estimation method

We consider the Victorian distributors' methods for deriving their LRMC estimates contribute to compliance with the pricing principles for direct control services.

We particularly commend CitiPower, Powercor, and United Energy for exploring alternatives to the AIC in estimating LRMC. We consider the use of a variant of the Turvey approach to produce location-specific LRMC estimates to represent a significant advance in LRMC estimation in the NEM.[97]

Regarding AusNet Services and Jemena, we consider the AIC approach is fit for purpose at this stage of tariff reform.

As we discuss in our assessment framework, long run marginal costs largely depend on the level of congestion in different locations within a network (as well as temporal factors). However, postage stamp pricing applies across the Victorian distributors' network and will continue to apply in the 2021–26 regulatory control period. This limits the extent to which end customers can receive and respond to long run marginal cost price signals.

In this context we consider the limitations of the AIC approach—the perception that the estimates they derive are not the best representations of long run marginal costs—are outweighed by its relatively low cost of implementation.[98] In particular, the AIC approach uses inputs that are readily available as part of a distributor's proposal: namely, the expenditure and demand forecasts for the 2021–26 regulatory control period.

Forecast horizon

We consider the Victorian distributors' proposed forecast horizons contribute to compliance with the pricing principles for direct control services.

The Victorian distributors used a forecast horizon of 10 years to derive their LRMC estimates. This meets the minimum 10-year forecast horizon that we consider adequately captures the 'long run'.

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96 NER, cl. 6.18.5(f)(1).

97 While CitiPower, Powercor and United Energy's consultant (ENEA) terms their LRMC method as the "marginal incremental cost" method, we understand it operates in principle like the Turvey approach.

98 NER, cl 6.18.5(f)(1).

Note on application of LRMC

The NER require the Victorian distributors to base their tariffs on their LRMC estimates.[99] Ideally, the price levels of charging parameters that represent such costs—such as the price during peak hours in time of use tariffs—should be at or near the LRMC estimates.

However, we acknowledge this may not always be the case at this stage of tariff reform for various reasons. For example, it is possible a general lack of congestion may mean LRMC estimates for a particular distributor are low. However, the distributor may reasonably wish to maintain differentials between peak and off-peak rates as part of its strategy to transition to more cost reflective tariffs. The peak rates in this example would comprise LRMC plus residual costs.

With their consultant Sapere, Evie Networks submitted that the Victorian distributors' tariffs do not adhere to the cost reflectivity principles in the NER. They submitted:[100]

- LRMC components of tariffs, such as peak time of use (TOU) and demand charges, are too high—Sapere states the Victorian distributors have been “over-recovering the LRMC component of their regulated costs.”
- Peak charging windows are too broad for TOU and demand charges. Sapere contends fast charging EV networks are again over-charged the LRMC component of charges as their peak loads do not coincide with the times of greatest network utilisation (demand is "infra-marginal").

Evie Networks submitted that this could result in under-utilisation of the EV fast and ultra-fast charging network as electric vehicles are adopted in coming years.

We understand that the Evie/Sapere submission is basically proposing that the Victorian distributors more closely base their tariffs on LRMC and that such signals be sent at times of greatest network utilisation. We agree that such a proposal is consistent with the intention of the NER to transition toward more cost reflective tariffs.[101]

However, we do not agree with several elements of the Evie/Sapere submission, as we discuss below.

Sapere stated the Victorian distributors’ LRMC components of tariffs, such as peak TOU and demand charges, are too high and so are over-recovering the LRMC component of their regulated costs. Figure 19.2 demonstrates Sapere’s analysis.

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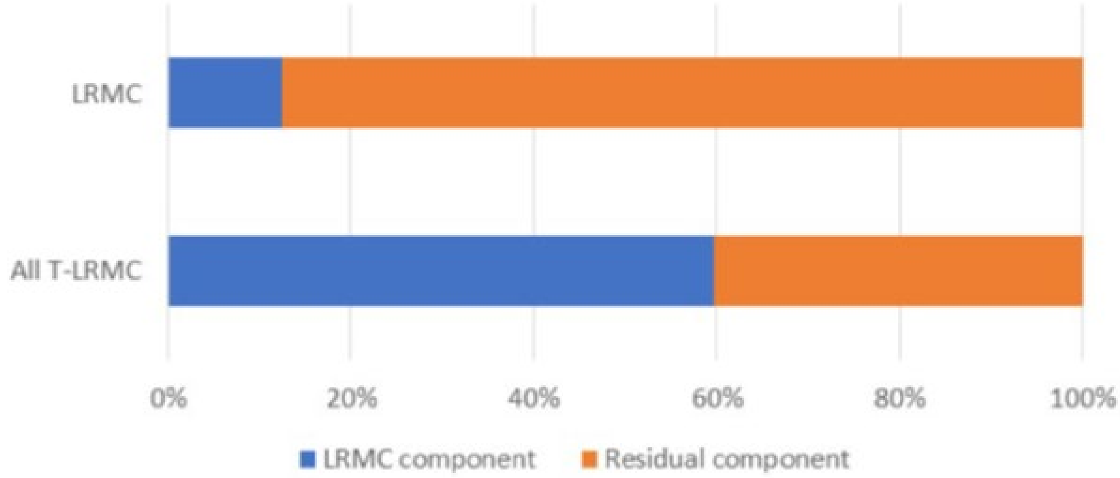
99 NER, cl. 6.18.5(f).

100 Sapere, *Australian Energy Regulator Issues Paper: Victorian electricity determination 2021–26: Assessment of electricity tariff structures and implications for public electric vehicle charging: Report for Evie Networks*, May 2020, pp. 2 and 3.

101 NER, cl. 6.18.5(f).

Figure 19.2 Vic distributor revenue recovery – LRMC and residual cost components (Sapere analysis)



Source: Sapere, *Australian Energy Regulator Issues Paper: Victorian electricity determination 2021–2026: Assessment of electricity tariff structures and implications for public electric vehicle charging: Report for Evie Networks*, May 2020, p. 2.

Sapere derived the bar chart labelled as “LRMC” by re-running the post tax revenue model (PTRM) with all net capex removed. Sapere appears to consider all net capex to be “forward-looking costs” and so represent the LRMC component of revenue requirements (the blue component of the "LRMC" bar chart). The resulting revenue requirement from the re-run PTRM therefore represents revenues from residual costs (the orange component).

Sapere derived the bar labelled as “All T-LRMC” using forecast revenues based on proposed prices (consistent with the TSS) and forecast volumes for each tariff. Sapere divided these tariff types into either forward looking (such as peak time of use or capacity) or “residual” (such as standing charges or off-peak). The total revenues for each component are then added together for all tariffs.

Sapere appears to consider that the “LRMC” chart indicates the appropriate allocation of LRMC and residual costs to revenues. This implies that the distributors' proposed charges that signal LRMC, such as peak TOU and demand charges, are too high.

However, we do not consider the “LRMC” chart appropriately represents LRMCs.

The AIC and Turvey methods are well accepted and most widely used approaches to estimating LRMC for pricing of electricity (and reticulated water) services and, as noted above, were endorsed for use by the AEMC in its review of network pricing principles. However, Sapere’s estimation of LRMC does not appear to be consistent with typical applications of these methodologies, or with other methodologies that estimate future costs.

Firstly, the inputs to the "LRMC" chart uses a forecast horizon of 5 years, which is appropriate for the PTRM. As discussed in the section above, however, we consider a forecast horizon should be at least 10 years to be considered "long run".

Secondly, Sapere included all capex net of capital contributions in the LRMC component of their analysis. As we discussed in previous final decisions, we require distributors to ensure the expenditure components they include in their LRMC estimates are consistent with the definition of "marginal cost". That is, they represent the costs of an incremental change in demand. We noted that not all repex meet this definition—for example, where they are triggered purely by asset age or condition. Similarly, other types of capex should be consistent with the definition of marginal cost if they are to be included in the LRMC calculation. However, Sapere did not appear to provide such justification except to note that all net capex are "forward looking."

In addition, we do not consider that "LRMC-based" tariffs—the basis for the "All T-LRMC" bar chart—equal LRMC levels at this stage of tariff reform. As discussed above, peak TOU tariff components may be higher than LRMC estimates and so are effectively comprised of LRMC and some residual costs. Alternatively, they may be lower, perhaps due to historical reasons whereupon the distributor is transitioning such tariff components toward the LRMC levels. We assess such tariffs on a case-by-case basis. Sapere also appear to categorise certain tariff types as "LRMC-based" even though their purpose is to recover residual costs. For example, Sapere noted capacity tariffs as being "LRMC-based" even though such tariffs do not necessarily signal future costs on the network due to increments or decrements demand.[102] Rather, we consider they recover backward-looking costs based on the size of a customer's connection.

Regarding charging windows, we understand Evie/Sapere may be proposing highly dynamic and locational pricing when they stated EV networks' peak loads do not coincide with the times of greatest network utilisation (and are therefore over-charged the LRMC component). We agree with the transition towards highly cost reflective network tariffs, having regard to the customer impact principle in the NER.[103] This is consistent with our position in previous assessments of tariff structure statements.[104]

As we discuss in the "Optionality" section for medium and large customers, we encourage the Victorian distributors to explore dynamic and locational tariffs for their revised proposal, where it is cost effective to implement. We agree that such developments would be positive steps toward more cost reflective network tariffs.

At this stage of tariff reform, we do not consider it is appropriate to require distributors to offer highly dynamic and locational general network tariffs. We acknowledge the transition to such tariffs still requires some "averaging" of the time and locational

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102 Sapere, *Australian Energy Regulator Issues Paper: Victorian electricity determination 2021–26: Assessment of electricity tariff structures and implications for public electric vehicle charging: Report for Evie Networks*, May 2020, p. 31.

103 NER, cll. 6.18.5(f) and (h).

104 AER, *Final decision: Tariff structure statements: Energex and Ergon Energy*, February 2017, p. 61.

signals that LRMC is intended to send to mitigate customer impacts.[105] This is consistent with our position in previous assessments of tariff structure statements.[106]

Peak windows, for example, are a compromise between cost reflectivity and mitigating customer impacts at this stage of tariff reform. Timing of peak utilisation of the network (and its implications for LRMC) often depend on location-specific factors such as spare capacity and the underlying customer base, as well other factors such as the time of day, type of day,[107] and season. Hence, requiring highly dynamic and locational general network tariffs would be more costly for distributors to administer, and may have adverse impacts on customers at this stage.[108]

Many distributors balance cost reflectivity with simplicity by treating their peak windows as the times of the day with the highest probabilities of peak utilisation. Put differently, LRMC recovered over wider peak windows send a signal of the times the distributor anticipates utilisation to be highest on its network as a whole. We consider this is a reasonable compromise at this stage of tariff reform. On the other hand, we are ensuring distributors' charging windows become more cost reflective with each TSS round as discussed in previous sections.

19.4.4 Statement structure and completeness

The Victorian distributors must include the following elements within their tariff structure statements:

- the tariff classes into which its customers will be grouped
- the policies and procedures the distributors will apply for assigning customers to tariffs or reassigning customers from one tariff to another (including applicable restrictions)
- the structures for each proposed tariff
- the charging parameters for each proposed tariff
- a description of the approach that each distributor will take in setting each tariff in each annual pricing proposal during the regulatory control period.[109]

Distributors must also accompany their proposed tariff structure statement with an indicative pricing schedule which sets out, for each tariff for each regulatory year of the

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105 NER, cl. 6.18.5(h) and (i). That is not to say these types of tariffs do not exist: they do to some extent. AusNet Services' CPD tariffs, for example, are intended to send a strong signal of the times of greatest network utilisation. Meanwhile, non-Victorian distributors generally offer very large customers ICC tariffs that are intended to send a strong locational signal.

106 AER, *Final decision: Tariff structure statements: Energex and Ergon Energy*, February 2017, pp. 46–47 and 60.

107 Workday, weekend, or public holiday.

108 This can be adverse financial impacts in a pure billing sense. However, it can also mean higher administration and implementation costs (for example, costs to adapt to such price signals).

109 NER, cl. 6.18.1A(a).

regulatory control period, indicative price levels determined in accordance with the tariff structure statement.[110]

The Victorian distributors' proposed tariff structure statements incorporate each of the elements required under the NER. The key focus of our assessment for this draft decision is on whether these elements satisfy the pricing principles for direct control services in the NER. In this respect we have identified a few areas that we encourage the distributors to more clearly describe in their revised proposals.

We recognise that the Victorian distributors adopted our preferred "two document" approach:

- the first document should include only include the aspects of the tariff structure statement that will bind them over the 2021–26 regulatory control period.
- the second document should explain their reasons for what it has proposed.

This approach improves the clarity for the retailers, customers, and the AER.[111]

19.4.4.1 Issues applicable to all five Victorian distributors

We note that while the distributors have clearly defined the tariff classes into which their customers will be grouped, a number of stakeholders have queried how these criteria have been set. For example, CitiPower, Jemena, and Powercor include a 120 kVA thresholds in defining their small business tariff class and United Energy uses a 150 kVA threshold. We understand this relates to the network operation and this being the threshold at which a customer can no longer be supplied through overhead lines. But we think it is important that the rationale behind these parameters is clearly explained to customers.

We consider more attention could be paid to explaining how the levels of the parameters in each structure will be priced and how any variations in allowed revenue will affect these prices. For example, if there is an under (over) recovery in revenue as a result of an unexpected fall (rise) in demand, how will the distributors allocate this increase (decrease) in revenue across the tariff classes and structures. While we do not require the distributors to adopt SA Power Network's approach[112] to establish relative ratios of all the parameters within each structure, we think more attention could be paid to explaining their approach to setting each tariff in each annual pricing proposal.

The distributors mentioned their intention to pursue network tariff trials with varying degrees of detail as to how they will approach this. We note that under the NER, the sub-threshold tariff clause[113] only applies to years two to five of the regulatory control

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110 NER, cl. 6.18.1A(e).

111 NER, cl. 6.18.5(i).

112 In Section 17.5.7 of the approved TSS, SA Power Networks outlines pricing relativity it has committed to complying with in its 2020–25 regulatory control period.

113 NER cl. 6.18.1C

period. For distributors to trial tariffs during 2021–22 these trials will need to be detailed in their revised tariff structure statements.[114] This applies to new trials, as well as continuation of existing trials such as Powercor's Newstead trial.

We encourage the distributors to review their presentation of the tariffs to ensure they are clear and complete. For example, in correspondence with AusNet they identified that the NEE24 tariff is a discounted primary controlled load tariff which provides AusNet with some control of the customer's heating between 8pm and 8am. But this is not clearly outlined in their tariff structure statement.

The distributors have largely relied on their explanatory statements to address the NER requirement to describe engagement with retail customers. This in itself is appropriate, however references in the tariff structure statement to content covered in the explanatory statement is often vague. We believe it would be more useful for the distributors, where they refer the reader of their tariff structure statement to the explanatory statement, to be specific about which area of the explanatory statement this engagement is covered in (for example, stating that large business retail customer engagement is discussed in section X of the explanatory statement).

19.4.4.2 Issues specific to AusNet Services

We require greater clarity in four areas of AusNet Services' revised tariff structure statement.

Firstly, AusNet Services provides details about a 'typical customer' for each of its tariff classes. The use of a 'typical customer' in each tariff class creates uncertainty around assignment. As such, we require the customer characteristics that result in assignment into each tariff class to be clearly outlined in the tariff structure statement (e.g. by providing specific annual consumption bands and voltage levels, rather than an example customer).

Secondly, we require AusNet Services to clearly outline its assignment policy for its medium business, large business (low voltage and high voltage), and sub-transmission tariffs. Tables 8 and 9 in the tariff structure statement provide a clear outline of how new and existing customers will be assigned to residential and small business tariffs. Similar tables for medium and large business and sub-transmission tariffs would provide an easy to read summary of AusNet Services' assignment policy for these tariffs. We are particularly keen for AusNet Services to provide clarity around its proposed assignment for medium business and large business (high voltage) tariffs.

Third, we require AusNet Services to outline how the proposed fixed value kVA capacity charge for its large business (low and high voltage) and sub-transmission tariffs will be determined. AusNet Services has not provided detail about how the capacity charge will be determined. For example, the charge could be a minimum chargeable demand amount or based on actual usage over a given period (likely the

[114] We have provided staff level guidance on tariff trials on our Network Tariff Reform webpage.

preceding 12 months). AusNet Services should provide a clear explanation of its proposed approach to the capacity charge and its determination.

Lastly, we require AusNet Services to clarify the process of nominating the days in which its critical peak demand charging parameter will apply. AusNet Services stated the critical peak demand charge is based on the "[a]verage of five recorded between 3:00 PM and 7:00 PM ADST on five days nominated in advance".[115] We require AusNet Services to set out in its revised proposal how these five days are "nominated in advance". For example, it is not clear from the initial proposal whether AusNet Services nominates the days at the start of each regulatory year. Alternatively, perhaps AusNet Services notifies customers of the nominated days on the day, or day before.

19.4.4.3 Issues specific to CitiPower and Powercor

We require CitiPower and Powercor to rectify an inconsistency in their proposals. Both distributors state in their assignment policy that the default tariff for medium business customers will be the demand tariff, comprised of a seasonal demand charge and flat usage charge. However, the tariff structure and charging parameters provided show that peak and off-peak charges are applicable for the medium business demand tariff (i.e. the tariff is listed as time-of-use in figure 6). The indicative pricing schedules provided by both distributors also split charges into peak and off-peak, although the same charges are listed for both time periods. CitiPower and Powercor must be clear in their revised proposals whether the default medium business tariff is to be a flat or time-of-use tariff.

Long run marginal cost models of CitiPower, Powercor and United Energy

We encourage distributors to continue providing the models they use to estimate long run marginal cost. This provides transparency to stakeholders regarding long run marginal cost calculations, including the contribution of a distributor's expenditure and demand forecasts to these calculations. This encourages discussion and investigation, which in turn adds to the knowledge base of methods to estimate long run marginal cost.

CitiPower, Powercor, and United Energy did not provide the model they used to estimate long run marginal cost. They noted their consultants, ENEA, performed their calculations on Python (rather than Excel) due to the number and complexity of calculations.[116] On the other hand, ENEA was open to continued discussion regarding their long run marginal cost model, which we welcome.[117]

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[115] AusNet Services, *Tariff Structure Statement 2022–26: Compliance document*, 31 January 2020, p. 11–12.

[116] CitiPower, *Tariff structure statement: CitiPower 2021–26*, 31 January 2020, p. 21; Powercor, *Tariff structure statement: Powercor 2021–26*, 31 January 2020, p. 22; United Energy, *Tariff structure statement: United Energy 2021–26*, 31 January 2020, p. 21.

[117] Meeting between staff from AER, CitiPower, Powercor, United Energy and ENEA on 26 February 2020.

We acknowledge the use of more specialised programs other than Excel may become more prevalent as the methods used to calculate long run marginal cost become more sophisticated, using more granular inputs.

We encourage distributors to continue providing such models for publication, where feasible. For example, we note that Python is a free, open source program. Where provision of the full model is problematic—due to overly large datasets or the use of sensitive information, for example—we encourage distributors to explore alternative formats for publication.

A Appendix A

Tariff structure statements cannot be developed in isolation from developments in the broader energy sector. Electricity distributors are required to develop their network tariff strategies against a backdrop of a unique set of environmental conditions. Some of these conditions will constrain the reform of network tariffs whilst other conditions will enable more reform to occur than otherwise the case.

The unique environmental factors relevant to a network pricing context include the following:

- Network design and operating conditions - the nature of the electricity network influences the level and spatial variation in LRMC of supplying an additional increment of network capacity.
- Penetration of interval metering – metering functionality is a critical enabler of efficient tariff reform.
- Price elasticity of demand – the extent that consumers respond to network pricing by changing their usage influences the design of efficient tariffs in a number of ways, such as from a residual cost recovery perspective.
- Economic conditions – variations in the business cycle influence the rate of growth in new network connections and investment in new major energy appliances and DER.
- Weather conditions – the seasonal nature of peak demand influences the design of efficient tariffs from a peak charging perspective.
- Retailer pricing behaviour – the extent that retailers pass through network pricing signals influences the nature, timing, and distribution of the benefits of tariff reform.
- Government intervention – government policy can influence the nature and pace of tariff reform.

The AER must take into account these unique environmental conditions when assessing whether a tariff structure statement proposal complies with the pricing principles for direct control services set out in Chapter 6 of the NER.

This appendix aims to provide background information and insights into the relevant retail pricing behaviours and government policies the influenced our draft decision.

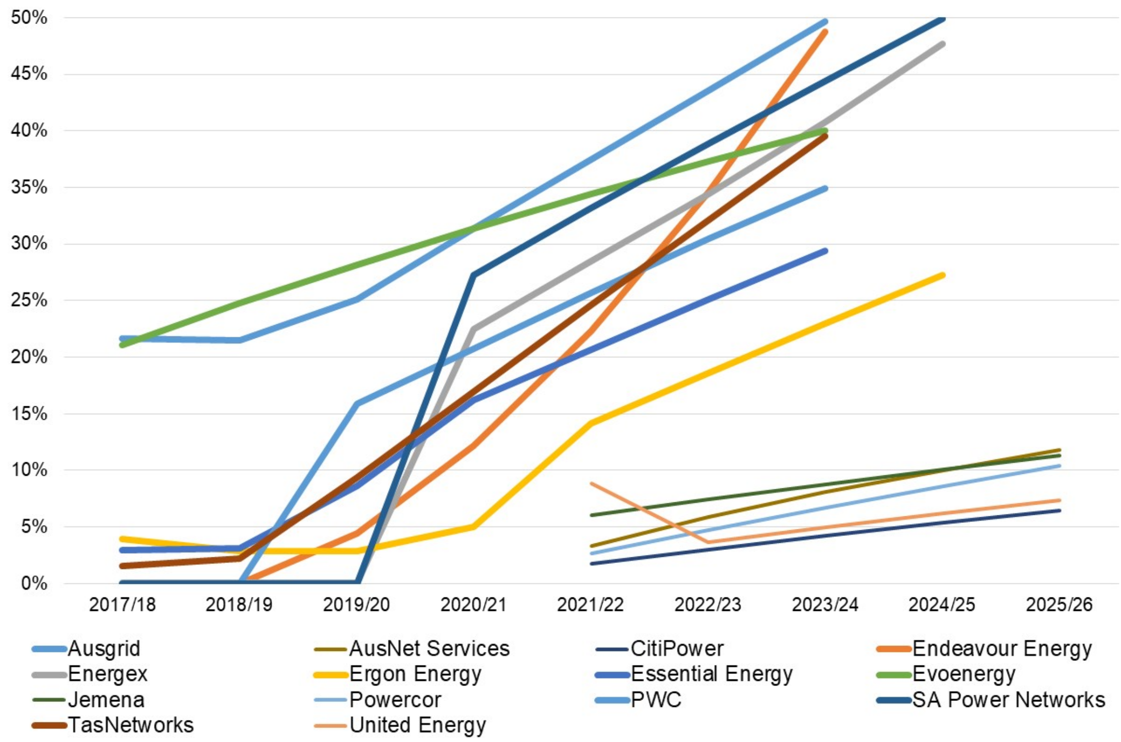
A.1 Proposed procedures for tariff assignment and reassignment

Unlike other networks across the NEM, all customers in Victoria have interval metering which can record the time and volumes of their consumption to enable implementation of more cost reflective network tariffs. However, this does not mean that all customers face cost reflective network tariffs. Instead more cost reflective tariffs (time of use or demand) have been offered on a voluntary or opt-in basis under the Victorian 2017–20 TSS. The exception is solar PV customers in AusNet Services' network who are no longer allowed to access the flat rate network tariff under the current TSS arrangements. The number of residential customers on tariffs other than flat rate tariffs in 2018 ranged from 6 per cent in Jemena's network to 25 per cent in AusNet Services' network.

These legacy network tariffs from the 2017–20 TSS' are a step forward from the use of flat rate consumption tariffs as they group consumption into peak and off-peak periods, with some tariffs also using shoulder periods. However, with the peak charging window sometimes set as wide as 7am to 11pm they are not comparable to the newly proposed tariffs with a more targeted peak charging window of 3pm to 9pm. We do not consider the legacy tariffs to be cost reflective for the 2021–26 regulatory control period.

Assignment to the new tariffs is proposed to be triggered by new connections, changes to current connections and/or installation of solar PV or batteries. The Victorian distributors expect this to result in only modest growth in the number of customers whose retailers face cost reflective tariffs. In comparison to the expected ten per cent of customers whose retailers will face cost reflective network tariffs in Victoria by the end of the 2021–26 regulatory control period, other networks across the NEM will have between 27 and 50 per cent of customers whose retailers will face such tariffs.

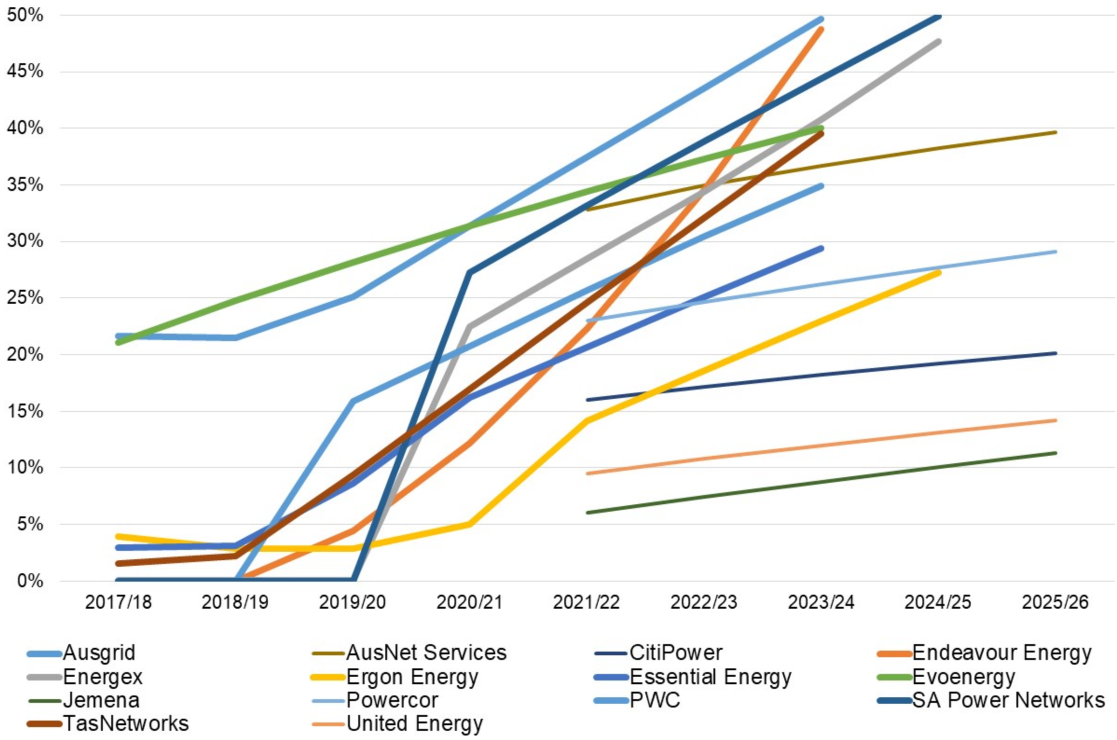
Figure 19.3 Percentage of residential customers whose retailers face cost reflective tariffs



Source: AER Analysis

In Figure 19.3 above, the dip in residential customers whose retailers will see cost reflective network tariffs in United Energy's network in 2022–23 is due to customers on time of use tariffs being reassigned to the legacy two rate (flat) tariff. However, should the customers on legacy time of use and demand tariffs across the five Victorian networks be reassigned to the new time of use and demand tariffs, Victoria would be roughly comparable to the rest of the NEM. If that were to occur, around 26 per cent of customers would have retailers facing these more cost reflective network tariffs. This state-wide average would be underpinned by 40 per cent of customers in AusNet Service's network, 20 per cent in CitiPower's network, 11 per cent in Jemena's network, 29 per cent in Powercor's network and 14 per cent in United Energy's network.

Figure 19.4 Percentage of residential customers whose retailers face cost reflective tariffs with legacy tariffs reassigned to new time of use tariff



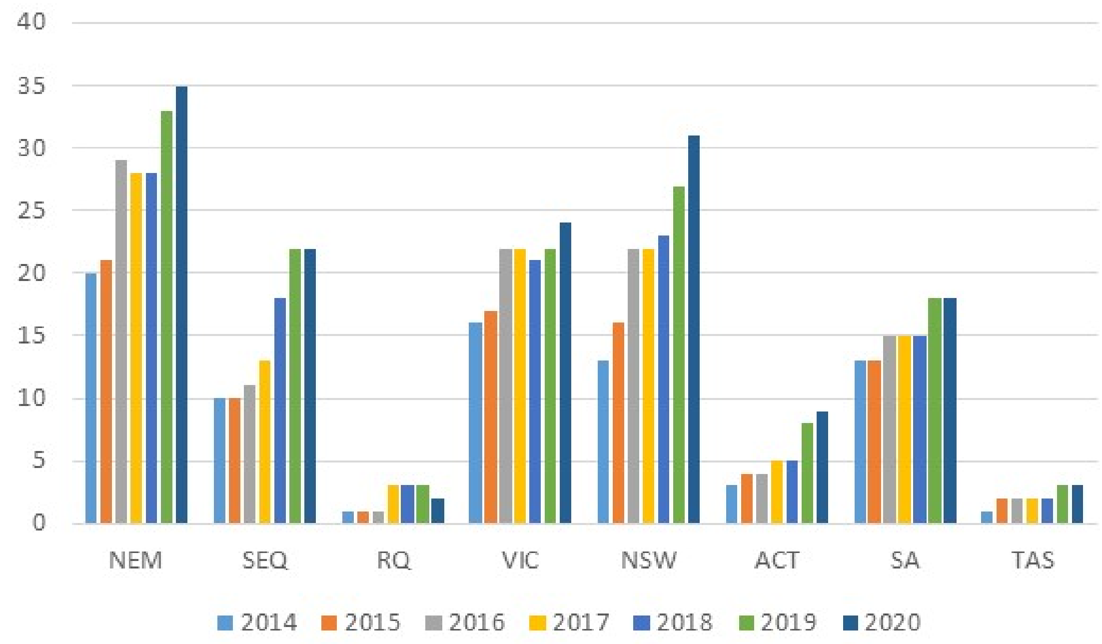
Source: AER Analysis

A.2 Retail pricing behaviours

As retailers are the focus of network tariffs, it is important to consider how they respond to these signals in developing their retail offers and the extent to which customers can choose the offer that best suits their needs. The electricity retail market in Victoria is competitive so all customers can choose their retailer and electricity plan. Customers who do not choose a plan are automatically moved onto their retailer's default standing offer.

The number of retailers providing offers to customers in Victoria has increased from 16 in 2014 to 24 in 2020. This compares to 35 retailers operating across the NEM and is second only to New South Wales in terms of the number of retailers competing for customers. This is illustrated by Figure 19.5.

Figure 19.5 Number of active retailers by state

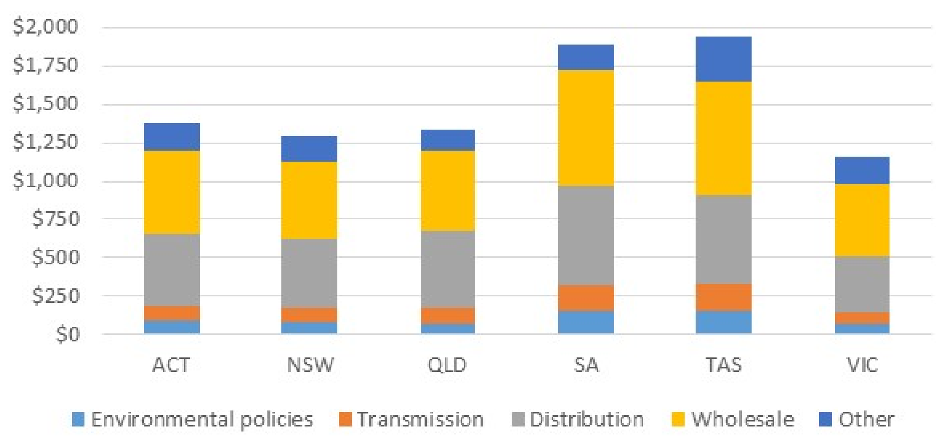


Source: AEMC Retail Energy Competition Review 2020.

Retailers are responsible for packaging up the various energy costs for their customers into different retail offers. These costs include the cost of purchasing the electricity, regulated electricity network services, environmental policies, and retail margins.

Figure 19.6 shows an estimate of the current supply chain cost components that underlie the annual retail electricity bill for a representative residential customers in each NEM region.

Figure 19.6 2019–20 Annual electricity supply chain costs by NEM region



Source: AEMC Residential Electricity Price Trends 2019

It is clear from the figure above that the wholesale energy purchases and the provision of electricity distribution and transmission services are the largest cost components in the underlying supply chain. Nevertheless, there is considerable variation in the relative share of each supply chain cost component across NEM regions.

These graphics also show the costs as a whole across the year. However, within the year retailers must manage dynamic wholesale purchase costs. Retailers may pass through network tariff price signals to customers through retail tariffs or they may choose to manage network price signals in other ways. The retailer does not need to pass all of these costs directly through to customers and it is in their approach to packaging these costs that they can compete to best meet customers' preferences.

We consider the potential approaches available to retailers to respond to cost reflective network tariffs can be grouped into three main categories:

- Insurance style – the retailer manages network price volatility on the customer's behalf and simply charges a fixed charge and flat kWh energy charge.
- Pass through offers – the retailer passes the price signals and associated volatility directly through to the customer for a lower margin.
- Prices for devices – the retailer (or third party) manages the customers' smart devices to respond to price signals and charges a simple, discounted retail structure.

Insurance and pass through offers are currently the norm but we are starting to see innovation emerge across all three categories. For example, the Reposit Power add on supports households with solar batteries to respond to more dynamic signals through a prices for devices style approach. We have also recently commissioned analysis from Baringa on the potential savings achievable for energy service providers (i.e. retailers or third parties) to create and share with customers through prices for devices. We would encourage all interested parties to read this report.[118]

A.3 Government policies

Government policies can influence the nature and pace of tariff reform by providing complementary initiatives. These initiatives can range from educational programs to subsidies and retail market regulation. For this reason, they are often a key consideration in relation to the customer impact principles which regulate the pace of network tariff reform in each network.

In Victoria we consider three main government policies to be key to our assessment of these principles:

- AMI Orders in Council
- Victorian Energy Compare
- VDO.

[118] This report has been published along with the results of our engagement with retailers to support the SA and QLD TSS decisions on our Network Tariff Reform webpage.

In Victoria the AMI Order in Council (introduced in 2013 and updated in 2015, 2016 and 2017) places a number of obligations on retailers and distributors in relation to cost reflective pricing. These include the requirement for retailers to provide a flat rate retail offer, for customers to be actively involved in any decision to move away from such an offer, and for interval metering data to be made available to customers. While the Order is due to sunset at the end of 2020, we understand DELWP is currently considering options to maintain these protections.

An additional obligation on retailers to provide information on generally available contract offers allows the Victorian Government to offer customers Victorian Energy Compare. This is a website where customers can share their interval data provided through either their retailer or distributor and the Victorian Government will advise them which retail offer would best suit their consumption behaviour.

Customers in Victoria also have access to the VDO. The VDO is determined by the ESC and is available to most Victorian households and small businesses. It is intended to provide an indication of the fair market price for standard retail electricity services and can be used as a point of comparison for customers to consider their options.

There are also obligations on retailers to periodically advise their customers whether they are on the best energy plan for their circumstances, and to provide energy fact sheets for their plans in a standardised format.

Shortened forms

Shortened form	Extended form
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AIC	average incremental cost
AMI	Advanced Metering Infrastructure
ARENA	Australian Renewable Energy Agency
augex	augmentation expenditure
capex	capital expenditure
CCP17	Consumer Challenge Panel, sub-panel 17
DELWP	Victorian Department of Environment, Land, Water and Planning
DER	distributed energy resource
DMIAM	demand management innovation allowance mechanism
distributor	distribution network service provider
DUoS	distribution use of system
ECA	Energy Consumers Australia
ESC	Essential Services Commission
EV	electrical vehicle
GESS	Gannawarra Energy Storage System
ICC	Individually calculated customer
LRMC	long run marginal cost
MWh	megawatt hour
NEL	National Electricity Law
NEM	National Electricity Market
NER	National Electricity Rules
opex	operating expenditure

Shortened form	Extended form
PTRM	post-tax revenue model
repex	replacement expenditure
RIN	regulatory information notice
TUoS	transmission use of system
VDO	Victorian Default Offer