DRAFT DECISION
Evoenergy
Distribution Determination

2019 to 2024

Attachment 18
Tariff structure statement

September 2018

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 Evoenergy for the 2019–2024 regulatory control period. It should be read with all other parts of the draft decision.

The draft decision includes the following documents:

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

Attachment 12 – Classification of services

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Glossary of terms

Term	Interpretation
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
Anytime demand tariff	A tariff incorporating a demand charge where the demand charge measures the customer's maximum demand at anytime (i.e. not limited to within a peak charging window).
Apparent power	See kVA
capex	capital expenditure
CoAG Energy Council	The Council of Australian Governments Energy Council, the policymaking council for the electricity industry, comprised of federal and state (jurisdictional) governments.
Consumption tariff	A tariff that incorporates only a fixed charge and usage charge and where the usage charge is based on energy consumed (measured in kWh) during a billing cycle, and where the usage charge does not change based on when consumption occurs. Examples of consumption tariffs are flat tariffs, inclining block tariffs and declining block tariffs.
Cost reflective tariff	Consistent with the distribution pricing principles in the NER, a cost reflective distribution network tariff is a tariff that a distributor charges in respect of its provision of direct control services to a retail customer that reflects the distributor's efficient costs of providing those services to the retail customer. These efficient costs reflect the long run marginal cost of providing the service and contribute to the efficient recovery of residual costs.
Declining block tariff	A tariff in which the per unit price of energy decreases in steps as energy consumption increases past set thresholds.
Demand charge	A tariff component based on the maximum amount of electricity consumed by the customer (measured in kW, kVA or kVAr) which is reset after a specific period (e.g. at the end of a month or billing cycle). A demand charge could be incorporated into either an anytime demand tariff or a time-of-use demand tariff.
Demand tariff	A tariff that incorporates a demand charge component.
distributor	distribution network service provider
DUoS	distribution use of system
Fixed charge	A tariff component based on a fixed dollar amount per day that customers must pay to be connected to the network.
Flat tariff	A tariff based on a per unit usage charge (measured in kWh) that does not change regardless of how much electricity is consumed or when consumption occurs.
Flat usage charge	A per unit usage charge that does not change regardless of how much electricity is consumed or when consumption occurs.
Inclining block tariff	A tariff in which the per unit price of energy increases in steps as energy consumption increases past set thresholds.
Interval, smart and advanced meters	Used to refer to meters capable of measuring electricity usage in specific time intervals and enabling tariffs that can vary by time of day.

Term	Interpretation
kVA	Also called apparent power. A kilovolt-ampere (kVA) is 1000 volt-amperes. Apparent power is a measure of the current and voltage and will differ from real power when the current and voltage are not in phase.
kW	Also called real power. A kilowatt (kW) is 1000 watts. Electrical power is measured in watts (W). In a unity power system the wattage is equal to the voltage times the current.
kWh	A kilowatt hour is a unit of energy equivalent to one kilowatt (1 kW) of power used for one hour.
LRMC	Long Run Marginal Cost. Defined in the National Electricity Rules as follows: *"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".*
Minimum demand charge	Where a customer is charged for a minimum level of demand during the billing period, irrespective of whether their actual demand reaches that level.
NEL	National Electricity Law
NEM	National Electricity Market
NEO	The National Electricity Objective, defined in the National Electricity Law as follows: *"to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to—* *(a) price, quality, safety, reliability and security of supply of electricity; and* *(b) the reliability, safety and security of the national electricity system".*
NEO	National Electricity Objective
NER	National Electricity Rules
opex	operating expenditure
Power factor	The power factor is the ratio of real power to apparent power (kW divided by kVA).
RAB	regulatory asset base
repex	replacement expenditure
Tariff	The network tariff that is charged to the customer's retailer (or in limited circumstances, charged directly to large customers) for use of an electricity network. A single tariff may comprise one or more separate charges, or components.
Tariff charging parameter	The manner in which a tariff component, or charge, is determined (e.g. a fixed charge is a fixed dollar amount per day).
Tariff class	A class of retail customers for one or more direct control services who are subject to a particular tariff or particular tariffs.
Tariff structure	Tariff structure is the shape, form or design of a tariff, including its different components (charges) and how they may interact.
Time-of-use demand tariff (ToU demand tariff)	A tariff incorporating a demand charge where the demand charge measures the customer's maximum demand during a peak charging window. A ToU demand charge might also include an off-peak demand change or minimum demand charge, and may include flat, block or time-of-use energy usage charges.
Time-of-use energy tariff	A tariff incorporating usage charges with varying levels applicable at different times of the day or week. A ToU energy tariff will have defined charging windows in which

Term	Interpretation
(ToU energy tariff)	these different usage charges apply. These charging windows might be labelled the 'peak' window, 'shoulder' window, and 'off-peak' window.
Usage charge	A tariff component based on energy consumed (measured in kWh). Usage charges may be flat, inclining with consumption, declining with consumption, variable depending on the time at which consumption occurs, or some combination of these.

18 Tariff structure statement

This attachment sets out our draft decision on Evoenergy's tariff structure statement for the 2019-24 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, its policies and procedures for assigning customers to tariffs, the charging parameters for each tariff and a description of the approach the distributor takes to setting tariffs. It is accompanied by an indicative pricing schedule.[1]

A tariff structure statement provides consumers and retailers with certainty and transparency in relation to how and when network prices will change. This permits consumers to make informed evaluations about their energy use and should result in better outcomes for them and the overall electricity system in the long term.

In particular, a tariff structure statement informs customer choices by:

- providing better price signals to better manage bills —tariffs which reflect what it costs to use assets such as substations and the poles and wires at different times .
- moving tariffs towards greater cost reflectivity over time—with the requirement that distributors explicitly consider the impacts of tariff changes on customers, by engaging with customers, customer representatives and retailers in developing network tariff proposals.
- managing future expectations—providing guidance for retailers, customers and suppliers of services such as local generation, batteries and demand management, through transparently setting out the distributor's tariff approaches for a five year period.

Background to this decision

This is Evoenergy's second tariff structure statement and applies to the 2019–24 regulatory control period. It must comply with the National Electricity Rules' distribution pricing principles.[2] These principles require distributors to transition to cost reflective tariffs and in doing so ensure that customer impacts from doing so are taken into account.

In the future direction section of our final decision on Evoenergy's (then known as ActewAGL) first tariff structure statement, we noted that transitioning to cost reflective pricing will take more than one regulatory control period to achieve.[3] We set an

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[1] NER, 6.18.1A(a).

[2] NER, cl. 6.18.5.

[3] AER, *ActewAGL Tariff Structure Statement final decision 2017*, 28 February 2017 p.14. This applied for the period 1 July 2017 to 30 June 2019.

expectation that to comply with the NER, each successive tariff structure statement should build on the first. [4]

Our final decision on Evoenergy's 2017–19 tariff structure statement conveyed elements which, in our view, would benefit from further consideration in future.[5]

Specifically, we identified that Evoenergy should:[6]

- refine its method for estimating long run marginal cost (LRMC), to include replacement capex within marginal cost estimates.
- reconsider the use of a 30 minute window to measure demand
- revise charging windows to more closely reflect the times of network congestion.

18.1 Evoenergy's proposal

Evoenergy's 2019–24 tariff structure statement seeks to continue the pricing reform it commenced in 2017 by[7]:

- maintaining its current tariff design and assignment policies for residential customers
- apply a different tariff assignment approach to LV commercial customers depending on whether they have embedded generation or not
- refine the tariff structure for large LV and HV commercial customers, by changing the 'anytime' maximum demand charges to 'peak period' demand charges.

18.2 Draft decision

Our draft decision is to accept the following elements of the Evoenergy's 2019–24 tariff structure statement tariff assignment and design for residential customers, as we consider that these contribute to compliance with the distribution pricing principles and to the achievement of the network pricing objective.

- A peak demand charge for LV and HV commercial customers replacing the 'anytime' demand charge

However, our draft decision is also to not accept the following elements of Evoenergy's tariff structure statement, and therefore to not approve the tariff structure statement as a whole, as we consider that each of these elements, and therefore the tariff structure statement as a whole, requires further work in order to fully comply with the distribution pricing principles in a manner that contributes to the achievement of the network pricing objective:

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4 AER, *ActewAGL Tariff Structure Statement final decision 2017*, 28 February 2017 p.14

5 AER, *ActewAGL Tariff Structure Statement final decision 2017*, 28 February 2017 p.14

6 AER, *ActewAGL Tariff Structure Statement final decision 2017*, 28 February 2017 p.14

7 Evoenergy, *Regulatory Proposal 2019-24, Attachment 17: Proposed Tariff Structure Statement*

- the assignment policy of LV commercial customers with embedded generation
- the change in default demand tariff structure from flat energy charges to time of use energy charges

18.3 Assessment approach

This section outlines our approach to assessing tariff structure statements.

There are two sets of requirements for tariff structure statements. First, the NER sets out a number of elements that an approved tariff structure statement must contain.[8] Second, a tariff structure statement must also comply with the distribution pricing principles.[9]

What must a tariff structure statement contain?

The NER requires a tariff structure statement to include:[10]

- 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
- structures for each proposed tariff
- charging parameters for each proposed tariff
- a description of the approach that the distributor will take in setting each tariff in each pricing proposal.

A distributor's tariff structure statement must be accompanied by an indicative pricing schedule with the tariff structure statement.[11] This guides stakeholder expectations about changes in network charges over the 2019-24 regulatory period.

What must a tariff structure statement comply with?

A tariff structure statement must comply with the distribution pricing principles for direct control services.[12] 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[13]

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8 NER, cl. 6.18.1A(a).
9 NER, cl. 6.18.1A(b).
10 NER, cl. 6.18.1A(a).
11 NER, cl. 6.8.2(d1).
12 NER, cl. 6.18.1A(b).
13 NER, cl. 6.18.5(e).

- each tariff must be based on the long run marginal cost 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.[14]
- 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[15]
- distributors must consider the impact on customers of tariff changes and may vary from efficient tariffs, having regard to:[16]
    - 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
- tariff structures must be reasonably capable of being understood by retail customers assigned to that tariff.[17]
- tariffs must otherwise comply with the NER and all applicable regulatory requirements.[18]

The distribution pricing principles must be undertaken in a manner that will contribute to the achievement of the *network pricing objective:*[19]

> *The network pricing objective is that the tariffs that a DNSP charges in respect of its provision of direct control services should reflect the DNSP's efficient costs of providing those services to the retail customer.*[20]

Role of the Tariff Structure Statement

In 2014, the 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.

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14 NER, cl. 6.18.5(f).
15 NER, cl. 6.18.5(g).
16 NER, cl.6.18.5(h).
17 NER, cl. 6.18.5(i).
18 NER, cl. 6.18.5(j); this requirement includes jurisdictional requirements.
19 NER, cl. 6.18.5(d)
20 NER, cl. 6.18.5(a)

Table 18-1 Two stage network pricing process

	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 distribution pricing principles. This document is submitted to the AER for assessment against the distribution pricing principles in conjunction with the distributor's five year regulatory proposal. The AER then approves the tariff structure statement if it meets the distribution pricing principles and other National Electricity Rules 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. 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.

Splitting the network pricing process into two stages was a significant change from the previous arrangements. The AEMC considered this would meet 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 distribution pricing principles and other requirements, and
- Distributors to maintain ownership of network tariffs and to adjust the pricing levels of their tariffs to recover allowed revenues.

What happens after a tariff structure is approved?

Once approved, a tariff structure statement will remain in effect for the relevant regulatory control period. The distributor must comply with the approved tariff structure statement when setting prices annually for direct control services.[21]

21 NER, cl. 6.18.1A(c).

We will separately assess the distributor's annual tariff proposals for the coming 12 months. Our assessment of annual tariff proposals will be consistent with the requirements of the relevant approved tariff structure statement.

An approved tariff structure statement may only be amended within a regulatory control period with our approval.[22] We will approve an amendment if the distributor demonstrates that an event has occurred that was beyond its control and which it could not have foreseen, and that the occurrence of the event means that the amended tariff structure statement materially better complies with the distribution pricing principles.[23]

18.4 Reasons for draft decision

Our draft decision is to not accept certain aspects of Evoenergy's proposed tariff structure statement, and therefore to not approve the tariff structure statement as a whole, as we are not satisfied that each of these aspects, and therefore the tariff structure statement as a whole, fully complies with the distribution pricing principles in a manner that contributes to the achievement of the network pricing objective.

While we are satisfied that, in most significant respects, the tariff structure statement contributes to compliance with the distribution pricing principles and to the achievement of the network pricing objective, we consider that certain sections of the tariff structure statement require amendment and further detail.

We set out below the reasoning for our decision for each customer group. We also discuss our assessment of Evoenergy's estimate of long run marginal cost and the completeness and compliance of the tariff structure statement with the requirements in the NER. We have also included a series of appendices which support these reasons.

We credit Evoenergy for being the most advanced distributor in reforming its residential and small business customer network tariff structures. This is based on the significant tariff reforms it proposed, and we approved, during the 2017–19 period. We consider a key enabler of this has been Evoenergy's consumer consultation process which has assisted Evoenergy improved cost reflectivity in its tariff structures while accounting for the customer impact principle.[24] In particular, the establishment and engagement of its Energy Consumer Reference Council has allowed Evoenergy to develop stakeholder understanding of its tariff framework and provide informed feedback. An example of Evoenergy's effective stakeholder engagement is the plain English explanation of the concepts underpinning its proposal to help stakeholders understand the purpose of tariff reform.

22 NER, cl. 6.18.1B.

23 NER, cl. 6.18.1B(d).

24 NER cll 6.18.5(a) and (h).

18.4.1 Residential and small business tariffs

We are satisfied the following aspects of Evoenergy's proposal for residential and small business customer tariff design contribute to compliance with the distribution pricing principles and to the achievement of the network pricing objective:

- a default cost-reflective tariff design that comprises a peak kW demand charge, a flat kWh energy charge and a fixed daily charge (cents per day).
- changing its anytime demand charge to a peak demand charge
- a tariff assignment policy permitting customers who are assigned to the default cost-reflective tariff to opt-out to a cost-reflective time-of-use consumption network tariff.

Despite this, we require Evoenergy to amend its tariff structure statement in its revised proposal to make it clear that that its default cost reflective tariff structure includes a flat energy charge rather than a time of use energy charge.

We discuss each of these issues in the sections below, first with respect to tariff design, levels and charging windows and then with respect to tariff assignment issues.

18.4.1.1 Tariff design, levels and charging windows

Default cost reflective tariff

Evoenergy's proposal states that it is changing its default cost-reflective tariff to consist of a seasonal peak demand charge, a time of use energy charge and a fixed daily charge.[25]

We consider demand charges are cost reflective to the extent Evoenergy's forward looking costs are driven by network expenditure to manage congestion at times of peak demand. Further, we are satisfied that time of use (TOU) energy charges are appropriate at this stage of tariff reform.[26]

Table 18-2 shows Evoenergy's the charging parameters and indicative price levels across the 2019-24 regulatory control period, for residential demand time of use tariff.

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[25] Evoenergy, *Regulatory Proposal 2019-24, Attachment 17: Proposed Tariff Structure Statement,* January 2018, p.32

[26] AER, *ActewAGL Tariff Structure Statement final decision 2017*, 28 February 2017 p.8

Table 18-2 Evoenergy residential kW demand tariff NUoS charges (code 25)

	2019-20	2020-21	2021-22	2022-23	2023-24
Daily Charge (cents)	28	29	31	33	35
Peak Energy Charge (cents/kWh)	4	5	5	5	5
Shoulder Energy Charge (cents/kWh)	4	5	5	5	5
Off-peak Energy Charge (cents/kWh)	4	5	5	5	5
Winter Peak demand charge (cents/kW/day)	16	17	18	19	20
Spring Peak demand charge (cents/kW/day)	16	17	18	19	20
Summer Peak demand charge (cents/kW/day)	16	17	18	19	20
Autumn Peak demand charge (cents/kW/day)	16	17	18	19	20

Source: Evoenergy, *Regulatory Proposal 2019-24, Appendix 17.3 TSS Indicative pricing schedule*

We note that Evoenergy tariff structure statement proposes to change the structure of the LV kW Demand tariff in the 2019–24 regulatory control period from a flat energy charge to a TOU consumption charge. Nonetheless it maintains the same rate for the peak, shoulder and off-peak consumption charges.[27] We requested that Evoenergy clarify why it had done this. [28]

Evoenergy indicated it intended to maintain the same price levels for each of the time of use periods throughout the 2019–24 regulatory control period. In doing so, Evoenergy highlighted that there had been insufficient time since the introduction of the flat energy demand tariff (1 December 2017) to analyse customer response to determine the appropriate pricing for the time varying energy charges.[29] We consider demand and energy charges which vary across time to coincide with network congestion will enhance cost-reflectivity.

We provide technical guidance on what we would expect of Evoenergy, and distributors in general to demonstrate compliance with the distribution pricing principles in appendix B and C. There we discuss our views on tariff assignment/design and estimation of LRMC.

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27 Evoenergy, *Regulatory Proposal 2019-24, Attachment 17: Proposed Tariff Structure Statement,* January 2018, p.23

28 AER, I*nformation request to Evoenergy #035*, 17 July 2018

29 Evoenergy, *Response to AER information request #035*, 24 July 2018

Refinement of anytime to peak demand charge appropriate

Evoenergy proposes to replace the anytime demand charge with a peak maximum demand charge for existing LV commercial customers.[30]

We are satisfied that this aspect of Evoenergy's tariff structure statements contributes to compliance with the distribution pricing principles and to the achievement of the network pricing objective, for the following reasons:

- network peak demand is the primary driver of network capacity costs; a particular customer’s peak demand as calculated under an “anytime” demand charge may not coincide with network peak;
- the nature of the distribution network in the ACT means that zone substations are usually predominantly residential or commercial but not both. Thus, peak commercial loads contribute to the local zone substation maximum demand and this enables a well targeted charging window to send effective price signals to these users
- an anytime demand charge may encourage a reduction in maximum demand from a particular customer, but does not encourage load-shifting to times where the network is not congested

We consider that peak demand charges during a peak charging window better reflect the likelihood that a customer’s maximum demand will coincide with the network peak.

This is most relevant for LV and HV network connections where customers' impacts on network costs are well understood. Maximum demand outside the peak charging window is unlikely to contribute to network congestion and network augmentation, so anytime demand is significantly less important at these times.

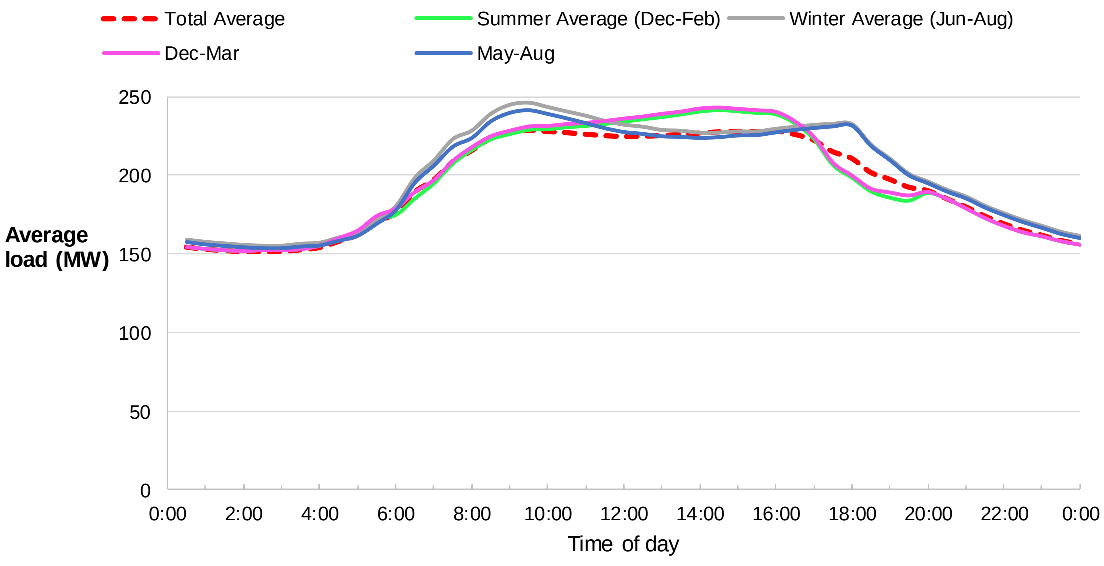
By separating the commercial load from the total network load, more refined peak charging windows can be applied to the commercial load. Evoenergy proposes the commercial peak demand charge be applied from 7am–5pm to align with local zone substation peaks rather than the total network peak.[31] We consider it likely that a demand charge targeted to a peak charging window will signal to customers the costs associated with coincident maximum demand. It incentivises customers to reduce demand and also load shift where possible.

We tested this by investigating the load profiles of the segments of Evoenergy's network which serve predominantly commercial customers. Figure 18-1 shows the relatively ‘flat’ commercial load profile during the 7am–5pm peak charging window is consistent through the year.

[30] Evoenergy, *Regulatory Proposal 2019-24, Attachment 17: Proposed Tariff Structure Statement,* January 2018, p.10

[31] Evoenergy, *Regulatory Proposal 2019-24, Attachment 17: Proposed Tariff Structure Statement,* January 2018, p.21

Figure 18-1 Commercial customer average load profile (2016)



Source: AER analysis

On this basis, we are satisfied that Evoenergy's proposed change from anytime demand charges to peak demand charges is appropriate. Further, we are satisfied that the charging windows these charges will apply to better reflects the contribution of customers to network congestion.

18.4.1.2 Tariff assignment policy

Evoenergy is proposing to maintain its current tariff assignment policies for residential and small commercial customers for the 2019–24 regulatory control period.[32] Evoenergy describes its process for assigning customers to particular tariff classes and tariffs, in particular:

- residential customers are assigned by default to the Residential kW Demand tariff where their premises are fitted with a Type 4 meter, but have the ability to opt out to the Residential TOU tariff only.[33]
- LV commercial customers with Type 4 meters are assigned, by default to the LV kW demand tariff but have the ability to opt out to the other cost-reflective tariffs.[34]

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32 Evoenergy, *Regulatory Proposal 2019-24, Attachment 17: Proposed Tariff Structure Statement,* January 2018, p.19 and p.40

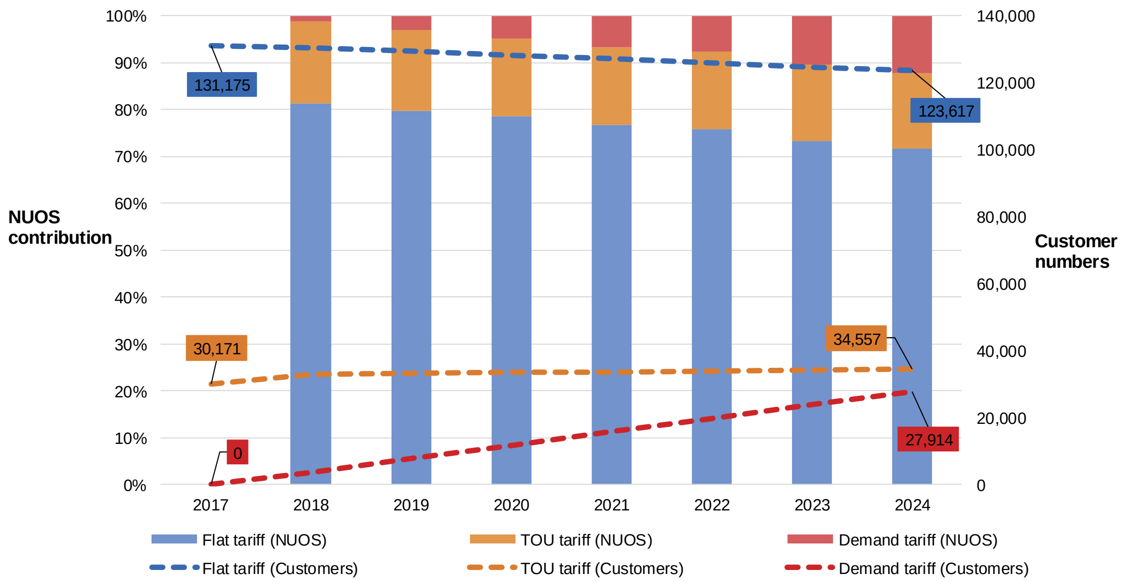
33 Evoenergy, *Regulatory Proposal 2019-24, Attachment 17: Proposed Tariff Structure Statement,* January 2018, p.40

34 Evoenergy, *Regulatory Proposal 2019-24, Attachment 17: Proposed Tariff Structure Statement,* January 2018, p.19

Pace of tariff reform

To determine the historic and forecast effectiveness of Evoenergy's approach to tariff reform we requested Evoenergy provide data on the penetration of cost-reflective tariffs historically and its projections for the 2019–24 regulatory control period. Figure 18-2 below illustrates this trend for the three main residential tariffs. Each of these tariffs has a separate structure - flat, time-of-use, and demand, respectively. .

Figure 18-2 Forecast customer numbers and NUOS (real $2018)



Source: AER analysis of Evoenergy response to AER information request #033

The above figure shows that:

- there will be a rebalancing of NUoS towards the demand tariff as more customers are forecast to be assigned to the demand tariff annually in the 2019–24 period.
- growth in forecast customer numbers of 14.5 per cent for the demand tariff will outstrip the forecast 13 per cent decline in customers on the basic flat tariff, relative to total customer numbers.

This highlights the gradual obsolescence of the flat (non-cost reflective) tariff over time as new connection customers and those receiving meter replacements are assigned to the demand tariff by default.

Minor amendment to trigger for tariff assignment required

The pace of tariff reform depends on the number of customers assigned to cost reflective tariffs, of which the trigger for tariff assignment or reassignment is a key driver. While we consider Evoenergy's proposed trigger for reassignment will stimulate tariff reform, we require Evoenergy to modify the trigger slightly so that it applies when:

(a) there is a new connection to the distributors network

(b) a customer initiates a change to their connection configuration that is identifiable to the distributor[35]

(c) a new meter is installed for any other reason, but with a 12 month delay for end of meter replacements

We consider that, by amending its trigger for reassignment, Evoenergy can better account for possible future changes to the visibility of distributed energy resources. Further, we consider that including a 12 month delay for end of life meter replacements will assist retailers in managing customer impacts on users who have not initiated a change to their circumstances. This period of delay will provide retailers load profile information which will better inform them on the retail tariff options suitable for these customers. We discuss this aspect in more detail in appendix B.

Opt-out to a cost-reflective network tariff appropriate

Evoenergy's tariff structure statement proposes to retain the ability for customers assigned or reassigned to the default cost reflective tariff to opt-out of this tariff to the other cost reflective network tariffs it offers.[36] Table 18-3 below illustrates Evoenergy's proposal.

Table 18-3 Evoenergy proposed options after (re)assignment triggered

Tariff class	Default cost reflective tariff	Network tariffs available after triggering (re)assignment
LV commercial	LV KW Demand	LV TOU Capacity LV TOU kVA Demand General TOU
Residential	Residential kW Demand	Residential TOU

Source: Evoenergy, *Regulatory Proposal 2019-24, Attachment 17: Proposed Tariff Structure Statement,* p.10 and p.32

We are satisfied Evoenergy's proposal is appropriate at this stage as it allows customers a choice of tariffs and allows greater management of customers' ability to understand tariffs and mitigate cost impacts. Further, we consider it appropriate at this stage of tariff reform that customers no longer be able to remain on legacy tariffs after they trigger (re)assignment to cost-reflective tariffs. We discuss this further in appendix B.

35 Changes to connection configuration include the installation of embedded generation and upgrades to three-phase power.

36 Evoenergy, *Regulatory Proposal 2019-24, Attachment 17: Proposed Tariff Structure Statement,* January 2018, p.19

Clarification required for assignment policy of LV commercial customers with embedded generation

Evoenergy's tariff structure statement proposes to retain its current tariff assignment policy for LV commercial customers for the 2019–24 regulatory control period.[37]

We sought clarification from Evoenergy about its tariff assignment policy for LV commercial customers.[38] Evoenergy's response indicated that the capacity tariff is not mandatory and the relevant customers have the same opt-out provisions as other customers.[39] We require Evoenergy to clarify this assignment policy in its revised proposal, as we consider that the language as it stands at present is at risk of misinterpretation.

18.4.2 Medium and large business tariffs

We are satisfied that Evoenergy's tariff design and assignment policies for higher voltage customers contributes to compliance with the distribution pricing principles and to the achievement of the network pricing objective.

We consider that Evoenergy's tariff structure statement appropriately assigns medium and large business customers to cost-reflective network tariffs while taking into account their connection and usage profiles. We set out our reasons for this decision below.

18.4.2.1 Tariff design, levels and charging windows

Evoenergy proposes to change the existing high voltage (HV) commercial tariff structure to replace the anytime demand charge with a peak maximum demand charge. Table 18-4 illustrates Evoenergy's proposal.

Table 18-4 Summary of proposed HV commercial tariff structure

	Fixed charge	TOU energy charge	kVA anytime demand	kVA peak demand	kVA capacity
HV TOU Demand	✓	✓	✓ →	✓	✓
HV TOU Demand - Customer LV	✓	✓	✓ →	✓	✓
HV TOU Demand - Customer LV & HV	✓	✓	✓ →	✓	✓

Source: Evoenergy, *Regulatory Proposal 2019-24, Attachment 17: Proposed Tariff Structure Statement,* January 2018, p.10

[37] Evoenergy, *Regulatory Proposal 2019-24, Attachment 17: Proposed Tariff Structure Statement,* January 2018, p.19

[38] AER, I*nformation request to Evoenergy #031*, 28 June 2018

[39] Evoenergy, *Response to AER information request #031*, 6 July 2018

We note that commercial customers connected at high and low voltage have similar load-profiles across the day, with the exception of some heavy manufacturing loads. Consistent with our decision on small commercial tariffs, we are satisfied the changing the demand charge from anytime to a peak window contributes to compliance with the distribution pricing principles and to the achievement of the network pricing objective.

In determining this, we are satisfied that network peak demand is the primary driver of network capacity costs; a particular customer's peak demand as calculated under an "anytime" demand charge may not coincide with network peak. For further discussion of our reasoning, see our analysis above on the refinement of anytime to peak demand charge (see section 18.4.1.1) for LV commercial customers. Appendix B below discusses in further detail our consideration of tariff design and cost-reflectivity.

18.4.2.2 Tariff assignment policy

Evoenergy is proposing to maintain its current approach to assignment policy.[40] That is, to continue assigning high voltage and large business customers to network tariffs based on their characteristics and the implications these could have on network costs. Given Evoenergy's existing HV tariffs are highly cost-reflective, we are satisfied that Evoenergy's proposed assignment policies for these customers contribute to compliance with the distribution pricing principles and to the achievement of the network pricing objective.

18.4.3 Long run marginal cost

An important feature of this draft decision is the concept of long run marginal cost. It 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.[41] Long run marginal cost could also be described as a distributor's forward looking costs that are responsive to changes in electricity demand.

The NER requires network tariffs to be based on long run marginal cost.[42] However, not all of a distributor's costs are forward looking and responsive to changes in electricity demand. If network tariffs only reflected long run marginal cost, a distributor would not likely recover all its costs. Costs not covered by a distributor's LRMC are called 'residual costs'. The NER requires 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.[43]

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[40] Evoenergy, *Regulatory Proposal 2019-24, Attachment 17: Proposed Tariff Structure Statement,* January 2018, p.20

[41] 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.

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

[43] NER, cl. 6.18.5(g)(3).

This section sets out our consideration of Evoenergy's approach to calculating long run marginal costs. We used the framework detailed in appendix C as the basis our assessment regarding compliance with the pricing principles.

Below we describe Evoenergy's approach to estimating LRMC (section 18.4.3.1). We then set out our assessment of this approach having regard to the framework in appendix C (section 18.4.3.2).

18.4.3.1Evoenergy estimation method

Evoenergy used the Average Incremental Cost (AIC) approach for estimating the long run marginal cost over a 10 year horizon. Evoenergy used the AIC approach after considering its costs and benefits against using different estimation methods such as the Turvey approach.

Compared to the 2017–19 tariff structure statement, Evoenergy made refinements to estimating the LRMC. The refinements included:

- improved precision in expenditure and demand inputs;
- investigating the inclusion of replacement expenditure; and
- LRMC estimates for each tariff class.[44]

Evoenergy’s network consists of 15 zone substations. Over a 10 year forecast horizon, 11 of these zone substations have forecast demand growth. For these zone substations, derived long run marginal cost estimates using the ratio of growth-related capex and opex to demand in those substations.[45] The LRMC estimates are presented in Table 18-5.

For substations with stable or declining demand, Evoenergy derived long run marginal cost estimates using the ratio of potentially avoidable repex to demand in those substations.[46]

Table 18-5: LRMC estimate for each tariff class

Tariff class	LRMC Estimate ($/kW p.a.)
Residential	212
LV Commercial	114
HV Commercial	26

Source: Evoenergy 2018[47]

[44] Evoenergy (formerly, ActewAGL Distribution) calculated a single, network-wide LRMC estimate in ActewAGL, *Revised Tariff Structure Statement,* 4 October 2016, p. 55

[45] Evoenergy, *HoustonKemp - Appendix 17.2 Proposed TSS detailed methodology_Public*, January 2018, p. 8–11.

[46] Evoenergy, *HoustonKemp - Appendix 17.2 Proposed TSS detailed methodology_Public*, January 2018, p. 7.

Evoenergy's LRMC estimates are based only on the 11 zone substations with increasing demand for two reasons. Firstly, Evoenergy uses postage stamp pricing across the network so there is no opportunity to distinguish price levels in areas of increasing, stable or declining demand.

Secondly, the growth in demand at these 11 zone substations is forecast to be five times greater than the areas of stable or declining demand.[48] In turn, this leads to LRMC estimates that are significantly below those for areas of growing demand—Evoenergy established indicative estimates for each tariff class of $7.90 per kW per annum for these areas.[49]

Given the application of postage stamp pricing, Evoenergy does not consider that replacement capex represents a long run marginal costs signal. Endeavour Energy submitted applying the lower long run marginal cost estimates (from substations with stable or declining demand) could lead to more inefficient consumption decisions.[50]

Compared with the LRMC estimates in Table 18-5 it is clear that adding the LRMC estimate in areas of stable or decreasing demand to those estimates would result in an average (postage stamp) LRMC signal too low to reflect long run costs of using the parts of the network where there is increasing demand. The upshot is that a higher residual cost recovery would be required. These outcomes are sub-optimal and in our view do not meet the network pricing objective.

18.4.3.2 Assessment of LRMC approach

We are satisfied that Evoenergy's approach to estimating long run marginal cost (LRMC) contributes to compliance with the distribution pricing principles and to the achievement of the network pricing objective..

Incorporation of repex into LRMC

We consider Evoenergy's proposed approach to incorporating repex into its LRMC estimates contributes to compliance with the distribution pricing principles and to the achievement of the network pricing objective.

Evoenergy investigated the inclusion of replacement capital expenditure (repex) into the LRMC estimates. The investigation involved identifying zones of increasing, stable or decreasing demand and to establish whether any potential replacement expenditure is avoidable. Evoenergy considered that:

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47 Evoenergy corrected the LRMC estimates in response to an AER information request: Evoenergy, *AER Query 31 Response Public,* 6 July 2018. Due to this correction, the LRMC estimates are different to the published LRMC estimates in Evoenergy, *Attachment 17 Proposed Tariff Structure Statement,* January 2018.

48 HoustonKemp, *Appendix 17.2 Proposed tariff structure statement methodology – Public,* January 2018, p. 8

49 Evoenergy, *Response to AER information request #036*, 27 August 2018, p. 2.

50 Evoenergy, *HoustonKemp - Appendix 17.2 Proposed TSS detailed methodology_Public*, January 2018, p. 9.

- in areas of increasing demand, the demand-driven component of replacement expenditure would be classified as augmentation expenditure and is not avoidable; and
- in areas of decreasing demand, the demand-driven component of replacement expenditure that is avoidable should be included in the LRMC calculations.

Evoenergy identified that four out of 15 zone substations are forecast to have stable or declining demand. As previously mentioned, Evoenergy only included capital expenditure and forecast maximum demand from the 11 out of 15 areas of forecast increasing demand. Thus, since the demand-driven expenditure (including repex) in areas of stable or declining demand is not included in the LRMC calculation, there is no demand-driven repex contribution to the LRMC estimates.

As mentioned, Evoenergy provided an indicative LRMC estimate ($7.90 per kW per annum) for areas of stable or declining demand. Given this value is significantly lower than the estimates in Table 18-5, neglecting the areas of stable or declining demand (and thus neglecting the repex contributions) is reasonable to avoid sending an average price signal too low that potentially underestimates the forward-looking costs of network usage in areas of increasing demand. Overall, we consider that the approach taken by Evoenergy is consistent with the definition of demand-driven replacement expenditure, long run marginal cost and the guidance we gave in the first tariff structure statement round.

For comparison. Endeavour Energy provided estimates for the LRMC for each tariff class for two scenarios.[51] The first scenario is for areas forecast to have increasing demand and the second is for areas forecast to have stable or declining demand. If relevant in the future, we encourage Evoenergy to provide LRMC estimates and calculation approaches for both scenarios with justification of the chosen estimates.

Estimation method

We consider Evoenergy's method for deriving its LRMC estimates contributes to compliance with the distribution pricing principles and to the achievement of the network pricing objective.

We consider the Average Incremental Cost approach is fit for purpose at this stage of tariff reform for Evoenergy.

As we discuss in appendix A, LRMC largely depend on the level of congestion in different locations within a network (as well as temporal factors). However, postage stamp pricing applies across Evoenergy's network and will continue to apply in the 2019–24 regulatory control period. This limits the extent to which end customers can receive and respond to LRMC signals.

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[51] Endeavour Energy, *TSS 0.04 Tariff Structure Explanatory Statement*, April 2018, p. 83 and 87

In this context, we consider the limitations of the Average Incremental Cost approach—the perception that the estimates they derive are not the best representations of LRMC—are outweighed by its relatively low cost of implementation.[52]

We also note Evoenergy improved its application of the average incremental cost approach by replacing a single, network-wide LRMC estimate with separate estimates for each tariff class. We consider this refinement more accurately reflects the contributions of each tariff class towards long run marginal costs. Furthermore, tariff class specific LRMC estimates result in avoiding the 'averaging' of estimates which would otherwise understate and overstate for some tariff classes.

Forecast horizon

We consider Evoenergy's proposed forecast contributes to compliance with the distribution pricing principles and to the achievement of the network pricing objective.

Evoenergy used a forecast horizon of 10 years to derive its LRMC estimate using the average incremental cost approach. This is equal to the minimum10 year forecast horizon that we consider adequately captures the 'long run' (see appendix A).

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

A Retail/network characteristics and relevance to tariff reform in Australian Capital Territory

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 enable more reform to occur than otherwise the case while others may constrain the reform of network tariffs.

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 long-run marginal cost 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.

We must take into account these unique environmental conditions when assessing whether a tariff structure statement proposal complies with the distribution pricing principles set out in Chapter 6 of the National Electricity Rules.[53]

This appendix aims to provide background information and insights into the unique environmental factors faced by each distributor from a network pricing perspective.

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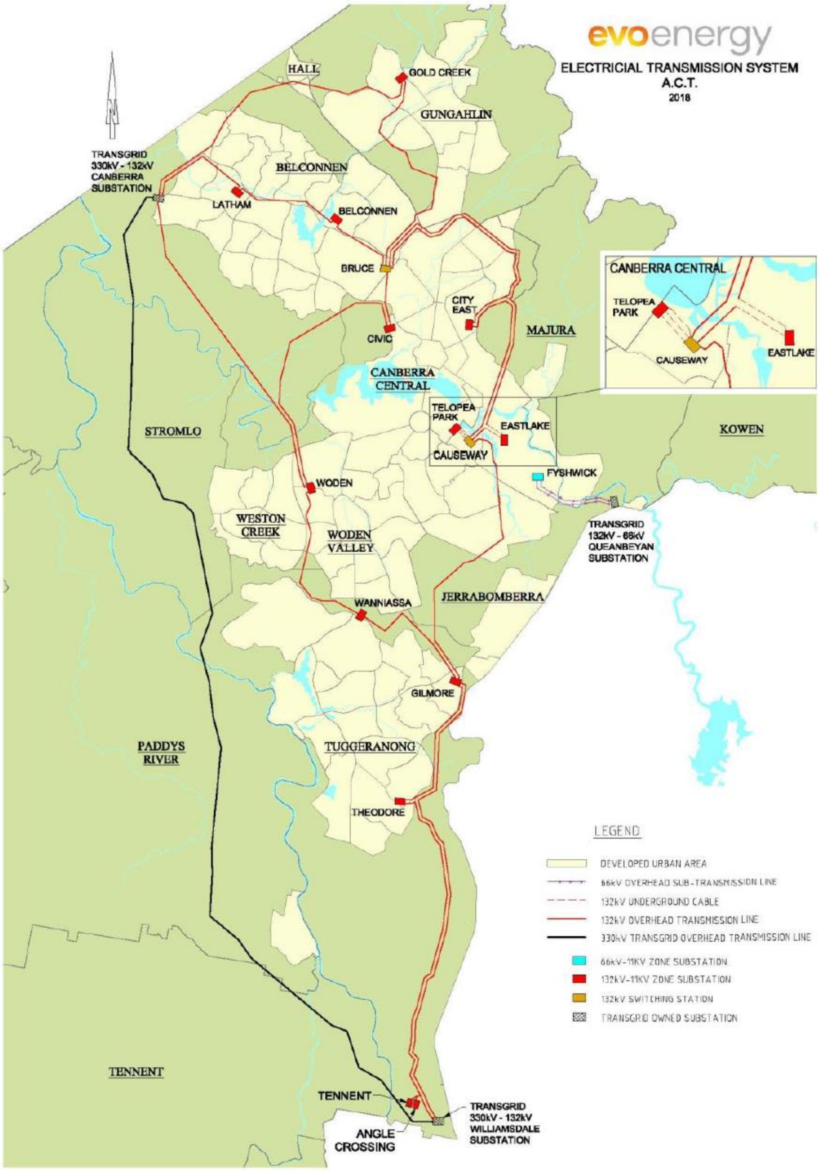
[53] NER 6.18.1A

Key Characteristics of Evoenergy Electricity Network

Evoenergy owns and operates the electricity network in the Australian Capital Territory (ACT), and gas networks in the ACT and surrounding areas in New South Wales (NSW).

Evoenergy owns and operates around 2,400 km of overhead electricity lines, 3,000 km of underground cables, and serves around 187,000 residential and commercial electricity and gas consumers, see Figure 18-3 below.

Figure 18-3 Evoenergy Electricity Network



Source: Evoenergy, *Regulatory Proposal Summary and Overview*, January 2018, p. 6

Evoenergy's electricity network comprises both electricity distribution and dual function (transmission) network assets. As a consequence, the AER is required to determine the revenue requirement for Evoenergy’s standard control services for distribution and transmission.

TransGrid sets transmission charges in its capacity as the Co-ordinating Transmission Service Network Provider in the ACT and NSW.[54] Nevertheless Evoenergy is the Distribution Network Service Provider and sets the prices for electricity network services, which reflect the costs of providing standard control transmission and distribution services.

Maximum Demand Growth

An important characteristic of Evoenergy's network is the rate of growth in maximum demand. Table 18-6 shows the current the Australian Energy Market Operator (AEMO) forecast of annual maximum demand by NEM region.

Table 18-6 Forecast Annual Maximum Demand (50% POE neutral scenario)

	NSW Summer	NSW Winter	Qld Summer	Qld Winter	SA Summer	SA Winter	Tas Summer	Tas Winter	Vic Summer	Vic Winter
2017	14 096	13 104	9 354	8 334	3 099	2 716	1 416	1 765	9 477	7 801
2022	13 902	12 954	9 546	8 574	2 947	2 674	1 398	1 741	9 340	7 712
2027	14 171	13 153	9 929	8 868	2 925	2 702	1 409	1 754	9 330	7 515

Source: AEMO, *2017 Electricity Statement of Opportunities*

From the above table we note the key insights are:

- Queensland is the only region forecast to experience growing maximum demand in both winter and summer to 2027.
- Forecast summer maximum demand is declining over the decade in South Australia and Victoria. Similarly, Tasmania and NSW is forecast to initially decline in demand with a projected upturn in expected demand in the latter part of this decade.
- Tasmania is the only NEM region that is winter peaking.

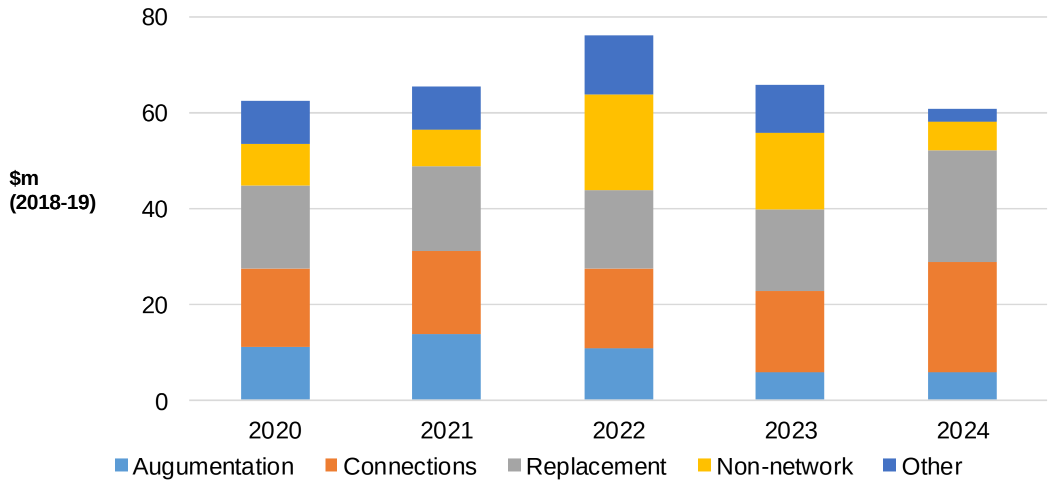
The moderation of the growth in peak demand has resulted in demand driven augmentation capital expenditure no longer being a major driver of network costs. As a consequence, it is expected replacement expenditure will be the dominant driver of capital expenditure for most distributors over the medium term. This increasing importance of replacement capital expenditure has implications for the design of cost reflective network tariffs.

Figure 18-4 shows the forecast decline in augmentation capital expenditure replacement-related capital expenditure will become the largest component of

[54] Evoenergy, *Regulatory Proposal 2019-24, Attachment 17: Proposed Tariff Structure Statement, Appendix 11.1: Transmission pricing methodology,* January 2018

Evoenergy's capital program for the provision of standard control services by the end of the regulatory control period.

Figure 18-4 Evoenergy forecast capex by driver



Source: Evoenergy, *Regulatory proposal for the ACT electricity distribution network 2019–24,* January 2018, p.29

Energy Consumption

Table 18-7 below shows the current AEMO medium term forecast of annual electricity consumption (in kWh) by NEM region.

Table 18-7 Forecast electricity consumption by NEM region

	NSW	Qld	SA	Tas	Vic
2016–17	67,958	51,144	12,442	10,046	42,879
2017–18	67,819	51,870	12,144	10,372	43,541
2018–19	66,727	51,890	11,949	10,421	42,828
2019–20	66,303	51,924	12,355	10,379	42,525
2020–21	66,101	52,039	12,259	10,347	42,514
2021–22	65,976	52,067	12,184	9,932	41,555
2022–23	65,703	52,416	12,120	9,907	40,639
2023–24	65,517	52,384	12,065	9,887	39,925
2024–25	65,588	52,372	12,023	9,901	39,060
2025–26	65,715	53,833	12,005	9,986	39,309
2026–27	65,918	53,961	11,989	10,072	39,514

Source: AEMO, *2017 Electricity Statement of Opportunities* p.41

We note the following from the table above:

- Queensland and Tasmania are forecast to be the only NEM regions to experience growth in electricity consumption over the decade to 2021-22.
- The majority of the growth in Queensland (+6 per cent) over this period reflects the recent growth in coal seam gas production.
- The modest growth in Tasmania (+0.3 per cent) reflects the expected weak growth in population and gross state product and continued growth in rooftop solar PV installations and improvements in energy efficiency.
- Annual electricity consumption is forecast to decline over the medium term in Victoria (-8 per cent), South Australia (-4 per cent) and New South Wales (-3 per cent).

The underlying composition of energy consumption by major customer segment is changing over time, reflecting the influence of energy conservation, uptake of energy efficient appliances and new energy technologies, price response and changes in the underlying structure of the economy away from energy-intensive sectors.

Another important driver of energy consumption is the adoption of distributed energy resources. Table 18-8 provides a regional comparison of the cumulative installation of solar photo voltaic systems by state and territory over the historical ten year period to 2017 period.

Table 18-8 Solar PV system installations by jurisdiction

	ACT	NSW	NT	QLD	SA	TAS	VIC
2008	278	2,890	88	3,087	3,456	161	2,036
2009	803	14,008	215	18,283	8,569	1,452	8,429
2010	2,323	69,988	637	48,697	16,705	1,889	35,676
2011	6,860	80,272	401	95,303	63,553	2,475	60,214
2012	1,522	53,961	513	130,252	41,851	6,364	66,204
2013	2,411	33,998	1,024	71,197	29,187	7,658	33,332
2014	1,225	37,210	1,026	57,748	15,166	4,207	40,061
2015	1,066	33,477	1,197	39,507	12,081	2,020	31,345
2016	1,001	29,495	1,745	34,422	12,604	2,487	26,724
2017	1,919	42,907	1,935	46,179	16,113	2,386	31,215
2018	1,425	28,079	871	25,567	10,154	1,273	17,406

Source: Clean Energy Regulator, *Postcode data for small-scale installations current as at 31 July 2018*

We consider that growth in solar PV installations over the past ten years reflects a number of factors, such as the falling real price of these systems, the incentives under existing energy-based electricity tariff structures and the influence of government subsidies. With the highest number of solar PV system installations have been recorded in Queensland, New South Wales, Victoria and South Australia.

The annual electricity consumption for a representative residential customer varies markedly, as shown in Table 18-9 below.[55] This variation reflects a broad range of influences such as differences in temperature conditions, the mix of appliances and the market penetration of gas for heating and cooking.

Table 18-9 Comparison of annual electricity consumption per residential customer by NEM region

Region	Annual electricity consumption (kWh) per customer
Queensland	5,240
New South Wales	4,215
Australian Capital Territory	7,151
Victoria	3,865
Tasmania	7,908
Northern Territory	6,613
South Australia	5,000

Source: AEMC, *2017 Residential Electricity Price Trends*, p.62

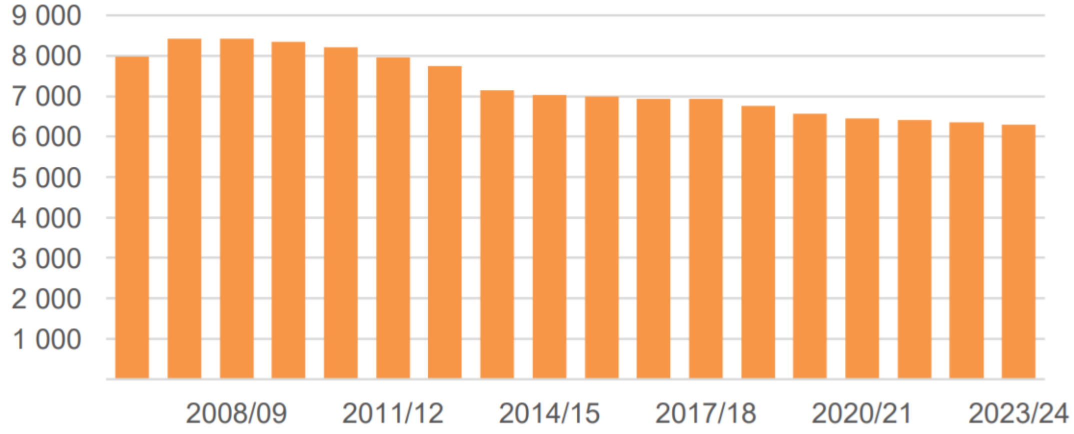
We note the following from the above table

- The influence of colder temperatures have resulted in Tasmania and the ACT having the highest annual residential electricity consumption in Australia.
- Victoria and New South Wales have the lowest annual residential electricity consumption, in part reflecting the higher penetration of gas for heating and cooking.
- Annual residential electricity consumption is similar in South Australia (5,000 kWh pa) and Queensland (5,240 kWh pa).

Average gross energy consumption per residential customer is forecast to decline over the next regulatory control period in Evoenergy's network area, see Figure 18-5 below.

55 AEMC, *Residential Electricity Price Trends Report* , 18 December 2017

Figure 18-5 Evoenergy - Actual and forecast residential average consumption

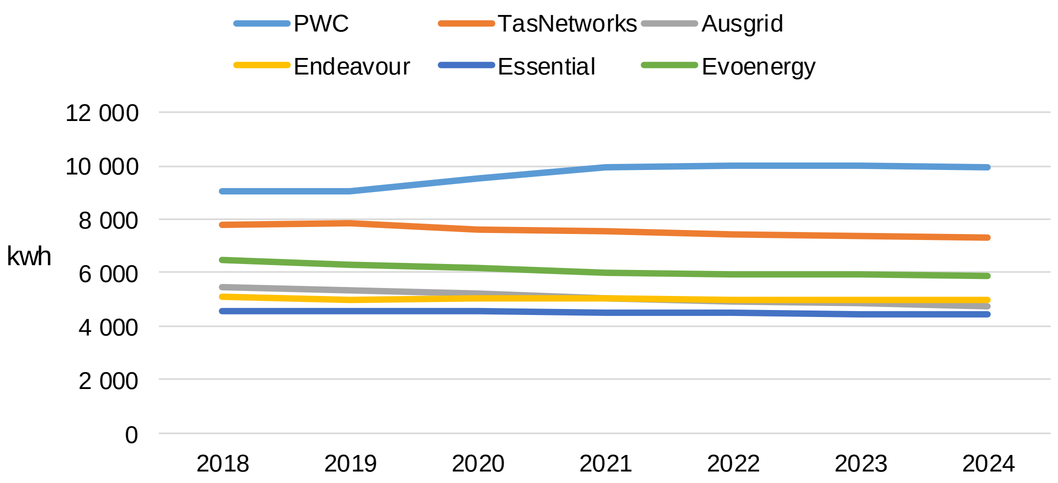


Source: Evoenergy, *Attachment 3: energy, customer numbers and peak demand forecasts, January 2018, p. 4*

Similar to national observations, the uptake of energy efficient appliances, competition with gas heating and cooking and the expected growth in solar PV installations under a net metering arrangement are driving this forecast.

Figure 18-6 compares the medium term outlook for average annual energy consumption per residential customer by selected DNSP. Interestingly TasNetworks and Power Water Corporation are the only DNSPs that do not expect residential energy consumption per customer to decline in the next regulatory control period over the medium term.

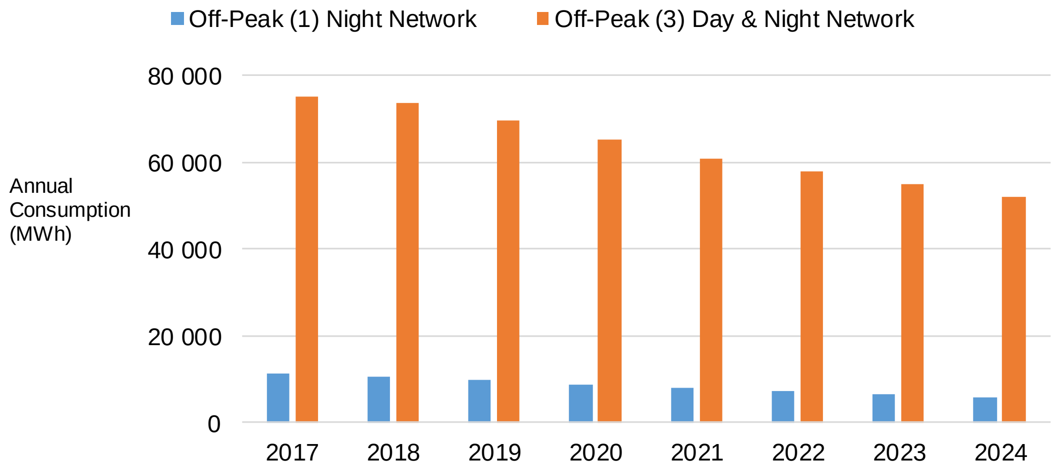
Figure 18-6 Comparison of residential average annual energy consumption



Source: AER analysis

Consistent with other jurisdictions, Evoenergy is forecasting a decline in the energy consumption under its controlled load network tariffs over the next regulatory control period, as shown in Figure 18-7 below.

Figure 18-7 Evoenergy - Controlled load energy consumption



Source: AER analysis

This forecast is likely to reflect a decline in number of controlled load customers in Evoenergy's network area. Factors such as fuel substitution (e.g. switching to solar from gas hot water) may be the underlying drivers of this decline. Further, introducing cost reflective pricing where a low network price is applied to uncontrolled energy consumption in off-peak times can reduce the incentive for customers to remain on controlled load tariffs.

Key insights into Evoenergy's energy consumption environment

Evoenergy is forecasting moderate growth in the number of customers connected to its network over the next regulatory control period (see Table 18-10). Population growth is likely to be the main driver of the expected growth in the number of energised connections.

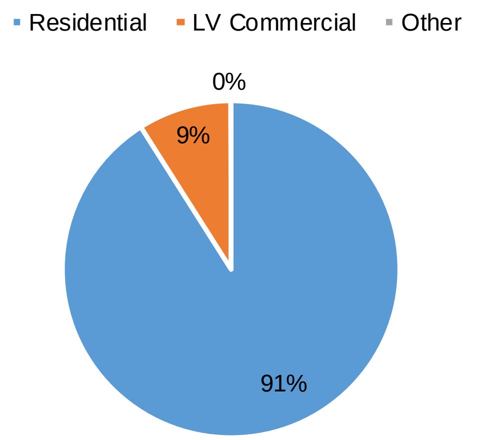
Table 18-10 Annual Customer numbers by type

	2018	2019	2020	2021	2022	2023	2024
Residential	176,116	178,871	181,765	184,691	187,612	190,506	193,367
LV Business	17,319	17,697	18,034	18,377	18,721	19,066	19,411
HV	28	28	29	29	30	30	31
Unmetered	45	46	47	48	48	49	50

Source: Evoenergy, *Attachment 3: energy, customer numbers and peak demand forecasts, January 2018, p. 8*

The residential and LV business segments in Evoenergy's network area account for a high annual share of total energy consumption and total customers (see Figure 18-8 and Figure 18-9).

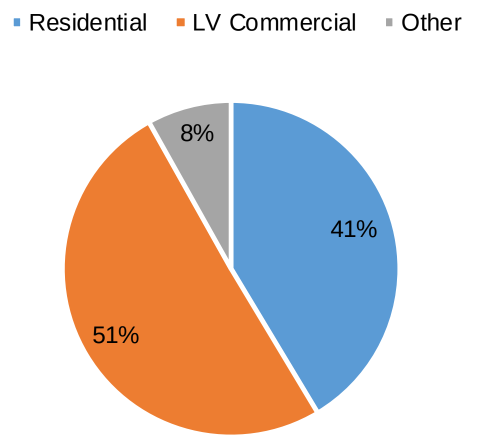
Figure 18-8 Evoenergy - Customer numbers by tariff class



Source: Evoenergy, *Attachment 3: energy, customer numbers and peak demand forecasts, January 2018, p. 8*

Evoenergy has a small number of high voltage-connected customers, but the large size of these customers means that they account for a material share of Evoenergy's total revenue each year, as shown below.

Figure 18-9 Evoenergy NUOS by tariff class



Source: AER analysis

Network costs, revenues and average network prices

The expected change in the annual revenue requirement is a key determinant of the pace of network tariff reform. This is because it is easier to gain overall customer acceptance of cost reflective pricing if the majority of customers are likely to pay less during the transition period to cost reflectivity.

Standard control Transmission use of system revenue

Table 18-11 shows Evoenergy has proposed a moderate real increase to its smoothed revenue requirement for the provision of electricity dual function transmission services over the next regulatory control period.

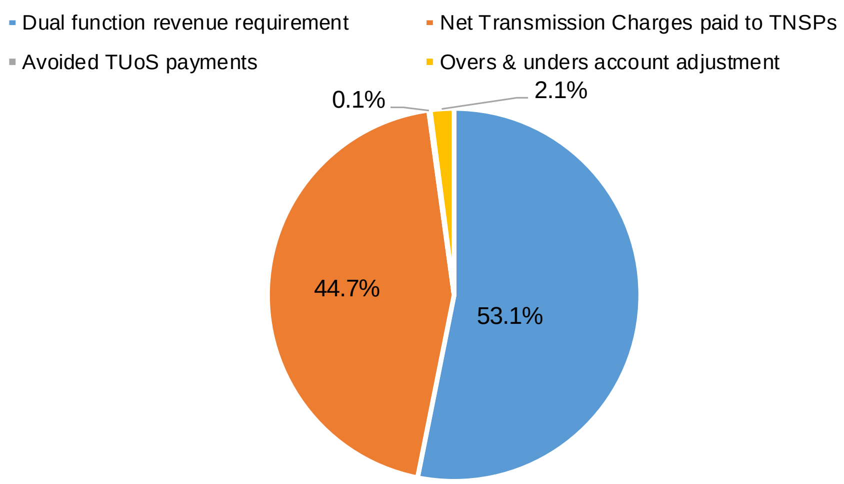
Table 18-11 Evoenergy - Proposed dual function revenue requirement

	2018-19	2019-20	2020-21	2021-22	2022-23	2023-24
Smoothed revenue ($m)	24.93	25.66	26.41	27.18	27.97	28.79

Source: Evoenergy, *Transmission Post Tax Revenue Model*, January 2018

Importantly, Evoenergy's dual function transmission revenue requirement is only one underlying element of its annual transmission-related costs recovered from customers through the annual setting of its Transmission Use of System (TUOS) tariffs. Figure 18-10 below shows the other components.

Figure 18-10 Evoenergy - Underlying drivers of Transmission Use of System Revenue 2018/19



Source: Evoenergy, *2018/19 Network Pricing Proposal*, March 2018 p.24

Standard control distribution revenue

Evoenergy has proposed a moderate real increase for the smoothed revenue requirement for its standard control distribution service during the next regulatory control period, as shown in Table 18-12.

Table 18-12 Evoenergy proposed distribution revenue requirement

	2018–19	2019–20	2020–21	2021–22	2022–23	2023–24
Smoothed standard control revenue ($m)	136.08	143.78	151.92	160.52	169.61	179.21

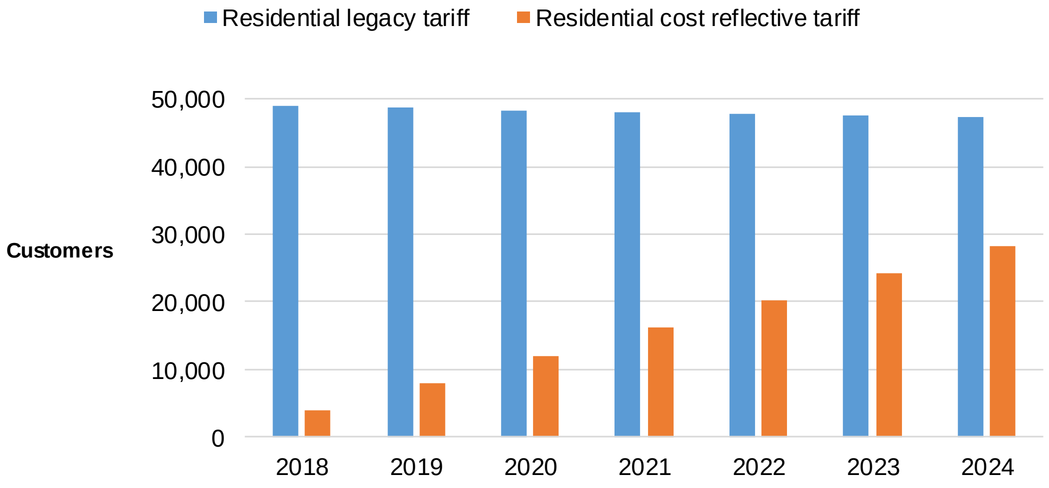
Source: Evoenergy, *Distribution Post Tax Revenue Model*, January 2018

Interval metering penetration

The penetration of interval metering is a relevant factor to consider from a network pricing perspective. Interval metering is a key enabling technology for cost reflective network pricing, it is only as customers have an interval meter installed in their premise are they able to be charged on a cost-reflective basis.

Figure 18-11 below shows the forecast number of residential customers with interval metering installed in their premise during the next regulatory control period, by cost reflective and legacy tariff groupings.

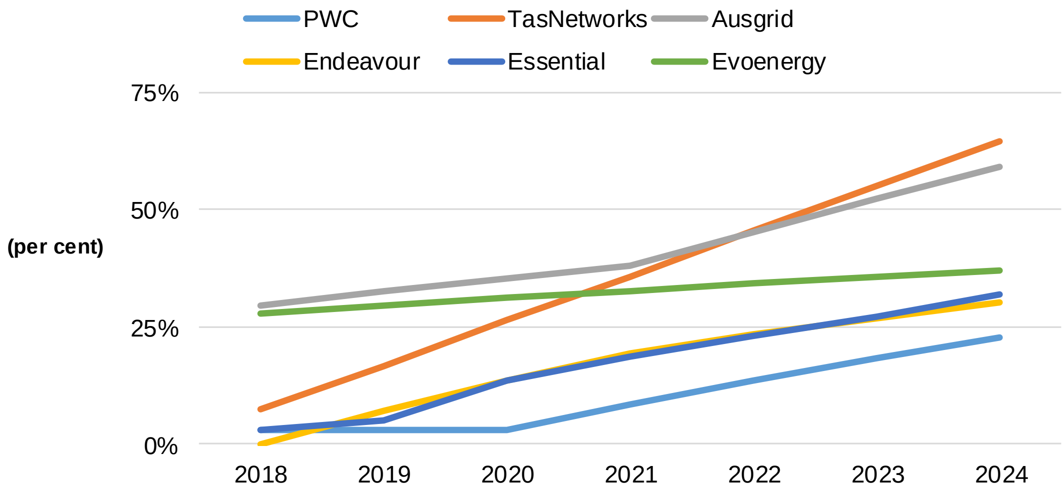
Figure 18-11 Evoenergy - Residential customers with Type 4 and 5 interval meters by tariff type



Source: AER analysis

The key point from the figure above is that Evoenergy is forecasting a marked increase in number of customers on a network demand tariff by 2024 under an opt-out approach to tariff reform. Figure 18-12 below compares the forecast number of interval metered customers by selected distributors with open regulatory determinations. This forecast growth reflects the installation of smart metering on a new and replacement basis, as required to comply with the new metering provisions in the National Electricity Rules.

Figure 18-12 Forecast proportion of residential customers with interval meters



Source: AER analysis

We note the following from the figure above:

- All distributors with open regulatory determinations are expected to have a significant penetration of interval metering in the residential sector by the end of the next regulatory control period.
- TasNetworks and Ausgrid are expected to have the highest penetration of interval metering in the residential customer segment with a penetration of 64 per cent and 59 per cent, respectively, by the end of the next regulatory control period.
- PWC are forecasting the lowest penetration of interval metering in the residential sector. Nevertheless, the penetration of Type 4 interval metering is expected to rise to around a quarter of all residential customers by 2024.

It is important to note that the extent that an increase in the penetration of interval metering translates to an increase in the number of customers on more cost reflective tariffs is dependent on the network tariff assignment and re-assignment policies of the distributor.

Comparing network tariff assignment procedures

Table 18-13 provides a comparison of the proposed tariff assignment policies for each distributor.

Table 18-13 Comparison of tariff assignment policies – residential customers

DNSP	Description of Proposed tariff assignment policy
Ausgrid	• Assign all new and existing customers with usage greater than 15 MWh pa to applicable demand tariff • Assign all new customers with usage between 2 MWh pa and 15 MWh pa to applicable seasonal Time of Use energy tariff • Existing customer that upgrade to an interval meter with usage between 2 MWh pa and 15 MWh pa to applicable seasonal Time of Use energy tariff • Assign all new and existing customers with usage less than 2 MWh pa to applicable transitional anytime energy tariff with the option of opt-in to applicable seasonal Time of Use energy tariff.
Endeavour Energy	• Assign all new connections will be assigned to the applicable transitional demand tariff with the option to opt-out to the flat energy tariff. • Existing connections that upgrade to a 3 phase or bi-directional flow will be assigned to transitional demand tariff with the option to opt-out to applicable flat energy tariff. • Allow existing customers with an interval meter (eg. due to end of life replacement) to remain on anytime energy tariff with option to opt-in to applicable demand tariff.
Essential Energy	• Assign all new connections and existing connections with a new occupant to applicable Time of Use energy tariff. • Assign all customers that connect new energy technologies (Solar PV, electric vehicles and battery) to applicable demand tariff • Allow existing customers that upgrade to an interval meter due to end of life replacement to remain on anytime energy tariff with the option to opt-in to applicable demand tariff.
TasNetworks	• Assign all new connections to the applicable anytime energy tariff. • Allow existing customers that upgrade to an interval meter due to change in connection characteristic to remain on applicable anytime energy tariff • Allow existing customers that upgrade to an interval meter due to end of life replacement to remain on applicable anytime energy tariff
Evoenergy	• Assign all new connections to demand tariff with the option of opt-in to applicable Time of Use energy tariff. • Assign all existing customers that upgrade to an interval meter to a demand tariff with the option of opt-in to applicable Time of Use energy tariff.
Power and Water	• Assign all new connections to applicable demand tariff with opt-out allowed to the applicable Time of Use energy tariff. • Re-assign existing customers that upgrade to an interval meter due to change in connection characteristic to applicable demand tariff with opt-out allowed to the applicable Time of Use

Source: AER analysis

We note the following key points from Table 18-13:

- TasNetworks proposed tariff assignment policy based on voluntary opt-in to cost reflective tariffs to 2023–24 will result a glacial pace of tariff reform compared to other jurisdictions. With the number of customers on legacy tariffs expected to increase over the medium term, it will take well over a decade to complete the transition to cost reflective pricing.

- Evoenergy and PWC propose to adopt a prescribed demand tariff assignment policy for all new customers and existing customers that have their basic accumulation meter replaced or upgraded.
- Evoenergy will allow customers on a demand tariff to voluntarily move to its time of use energy tariff.
- Essential Energy propose to adopt a prescribed demand tariff assignment policy for all new customers and existing customers that upgrade to an interval meter for purpose of a connecting a Solar PV system, battery or electric vehicle charger to the electricity network.
- Endeavour Energy proposes to require that all new customers and existing customers that upgrade to a 3 phase connection will be assigned to a transitional demand tariff with the option of voluntarily opt-in to the cost reflective demand tariff.
- Ausgrid propose to adopt a prescribed cost reflective tariff assignment policy for all new and existing residential customers with a Type 4 meter installed that consume more than 2 MWh pa. Customers that consume less than 2 MWh pa will be assigned to an anytime energy tariff with the option to voluntarily opt-in to the more cost reflective seasonal time of use tariff.

Tariff classes

Distributors are required under Clause 6.18.3(b) of the National Electricity Rules to group their customers into tariff classes for the purpose of setting the prices of standard control network services. Tariff classes are important because both the efficiency bounds test and the side constraints apply at the tariff class level.

Table 18-14 provides a summary of the current tariff classes for each distributor, it shows there is a considerable variation in the extent of tariff class disaggregation, particularly in respect to customers connected at the low voltage level of the electricity network.

Table 18-14 Current tariff classes by distributor

Ausgrid	Endeavour Energy	Essential Energy	TasNetworks	Evoenergy	Power and Water
	Low voltage energy	Low voltage energy	Residential	Residential	Less than 750 MWh per annum
Low voltage	Low Voltage Demand	Low voltage Demand	Small low voltage Large low voltage Uncontrolled energy Controlled energy	Commercial low voltage	More than 750 MWh per annum
High voltage	High voltage	High voltage	High voltage	High voltage	High voltage

Ausgrid	Endeavour Energy	Essential Energy	TasNetworks	Evoenergy	Power and Water
Sub-transmission Voltage Transmission-connected	Inter-Distributor Transfer (IDT)	Sub-transmission Voltage	Individual Tariff Calculation Class		
Unmetered supply	Unmetered supply	Unmetered supply	Unmetered supply		

Source: AER analysis

Network tariffs

Network Use of System (NUoS) tariffs in Australia typically comprise the following components:

- Distribution Use of System (DUoS) component – relates to the cost of providing standard control distribution services, plus an adjustment for the overs and unders account of the revenue cap control mechanism and any pass through amounts approved by the AER.
- Transmission Use of System (TUOS) component – this relates to the cost of providing standard control transmission services, plus an adjustment for the overs and unders account of the revenue cap control mechanism and any pass through amounts approved by the AER.
- Jurisdictional scheme amount component – this element only applies where a DNSP is required to contribute to a Jurisdictional scheme imposed by a state or territory government, plus an adjustment for the over/ under recovery of the actual contribution amount payable.

Overview of current network tariffs

Table 18-15 provides a summary of the network tariff structures for residential and small business customers in the NEM. While all of these tariffs comprise a fixed charging parameter, the structure usage charging parameter varies considerably for both legacy tariffs and the more cost reflective tariffs.

Table 18-15 Network tariff structures by distributor

DNSP	Legacy Tariff			Cost Reflective Tariff			
	Fixed charge	Uniform energy charge	Block kWh charge	Fixed charge	TOU energy charge	Uniform energy charge	Demand energy charge
Ausgrid	●		●	●	●		
Endeavour Energy	●	● [1]		●		●	●
Essential Energy	●		●	●			●
TasNetworks	●	●		●			●
Evoenergy	●		●	●		●	●
Power and Water	●	●		●		●	●

Source: AER analysis [1]: Endeavour Energy propose to maintain the existing inclining block tariff structure for small business customers

Key statistics for Network tariffs

Table 18-16 shows the number of customers and Network Use of System revenue for the major tariffs for residential and small business customers by distributors open regulatory determinations.

Table 18-16 Key statistics - current network tariffs

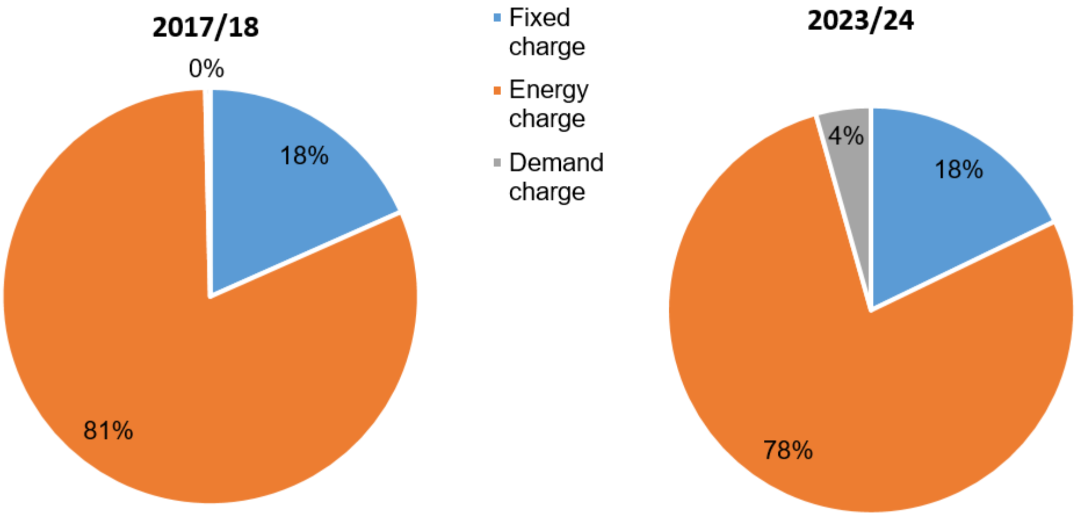
	Legacy Tariff			Cost Reflective Tariff		
DNSP	**Network Tariff Name**	**Number of Customers**	**NUOS Revenue ($m)**	**Network Tariff Name**	**Number of Customers**	**NUOS Revenue ($m)**
Ausgrid	Residential non-TOU (EA010)	1,115,128	623.1	Residential TOU (EA025)	354,965	238.9
	Small business non-TOU (EA050)	68,250	88.6	Small business TOU (EA225)	75,618	134.2
Endeavour Energy	Residential non-TOU (N70)	912,951	524.0	Residential TOU(N705)	58	0.02
	General supply non-TOU (N90)	75,535	155.1	General Supply TOU (N45)	2,055	14.7
Essential Energy	LV Residential anytime (BLNN2AU)	727,622	541.5	Residential TOU (BLNT3AU)	23,115	23.1
	LV Small Business Anytime (BLNN1AU)	81,851	155.8	LV TOU < 100MWh Cent Urban (BLNT2AU)	10,596	70.5
TasNetworks	Residential LV (TAS31)	217,966	119.6	Residential TOU TAS93/92)	6,207	3.8
	Uncontrolled LV heating (TAS41)	209,534	53.9	Residential TOU demand(TAS87)	219	0.18
	Business LV General (TAS22)	29,041	37.7	LV Business TOU (TAS94)	4,289	33.7
Evoenergy	Residential basic (010,011)	129,356	73.3	Residential demand (025,026)	7,693	2.7
	General supply (040,041)	11,158	25.8	LV Demand (106,107)	1,617	7.0
Power and Water	Domestic	74,518	86.1	LV Smart meter <40MWh	0	0
	Commercial	13,127	54.2	LV Smart meter >40MWh	0	0

Source: AER analysis

Evoenergy network tariffs

Figure 18-13 below shows the annual Network Use of System revenue share by charging parameter type for the main residential tariffs.

Figure 18-13 Evoenergy - NUoS revenue share by charging parameter for major residential tariffs



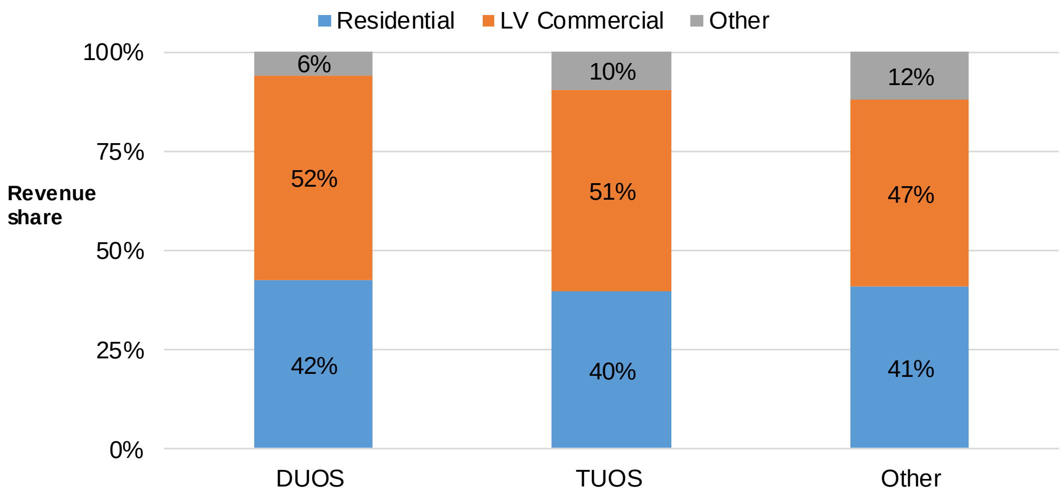
Source: AER analysis

Figure 18-13 above highlights that Evoenergy proposes to adopt a gradual approach to rebalancing its network tariffs in the next regulatory control period.

The progress towards more cost reflective pricing is due mainly to Evoenergy's prescribed approach to assignment of demand tariffs, rather than a proposed tariff re-balancing noting that the annual revenue share by parameter is expected to remain largely unchanged over this period. The appropriateness of a gradual approach to network tariff reform is assessed in the context of the customer impact principle in Chapter 6 of the National Electricity Rules.

Figure 18-14 shows the annual network use of system revenue share by major customer segment at the DUoS, TUoS and jurisdictional scheme component level in 2018-19.

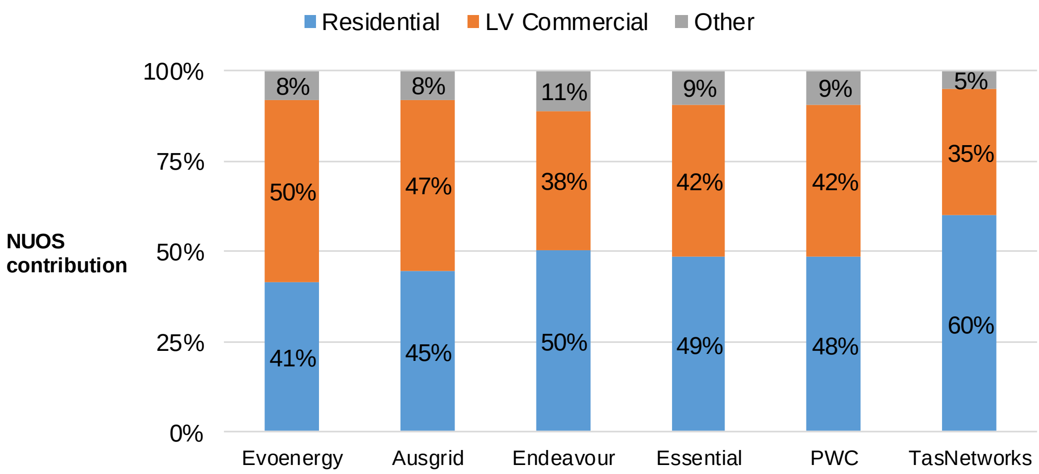
Figure 18-14 Evoenergy network revenue by customer segment 2018/19



Source: AER analysis

The low voltage commercial customer segment is to account for around half of Evoenergy's annual revenue requirement in 2018-19. This level of reliance on the LV commercial customer segment is high compared to other distributors, see Figure 18-15 below:

Figure 18-15 Comparison of NUoS revenue by customer segment 2018/19



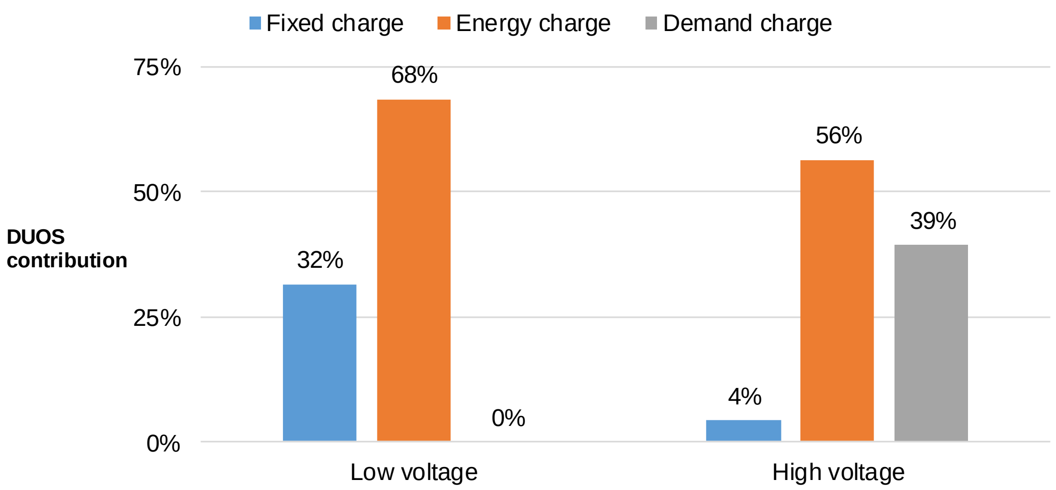
Source: AER analysis

To understand Evoenergy's network tariffs, it is necessary to look at the underlying level and structure of the tariffs at the DUoS, TUoS and jurisdictional scheme amount level.

Evoenergy's Distribution Use of System (DUOS) Tariffs

Figure 18-16 compares the annual DUOS revenue share by charging parameter type at the low voltage and high voltage level in 2018-19.

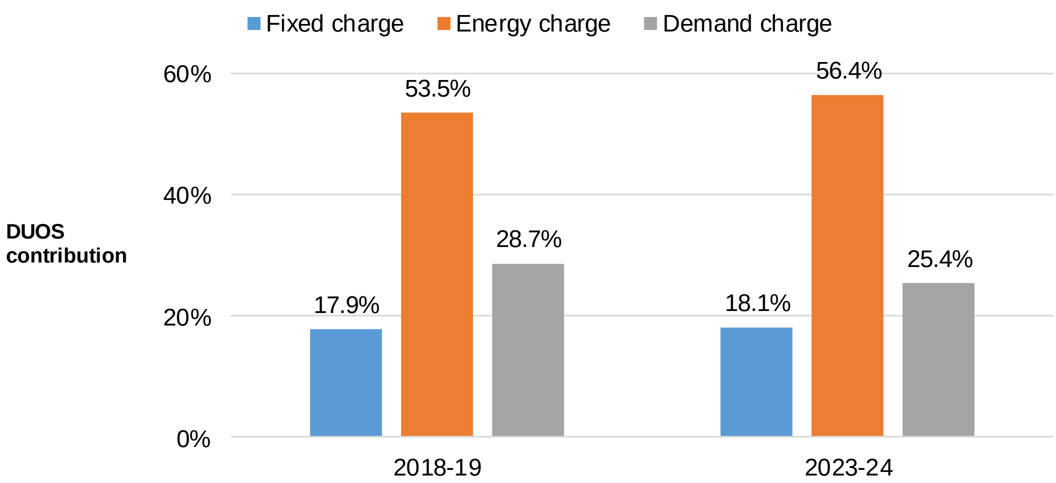
Figure 18-16 Evoenergy - DUoS revenue share by charging parameter and voltage level 2018/19



Source: AER analysis

Evoenergy DUoS tariffs for low voltage-connected customers is currently heavily reliant on energy consumption compared to the high voltage- connected tariffs. This difference in pricing approach is primarily due to the limitations of basic accumulation metering in the low voltage customer segment. Figure 18-17 shows the indicative annual DUoS revenue share by charging parameter between 2018-19 and 2023-24.

Figure 18-17 Evoenergy - DUoS revenue share by charging parameter



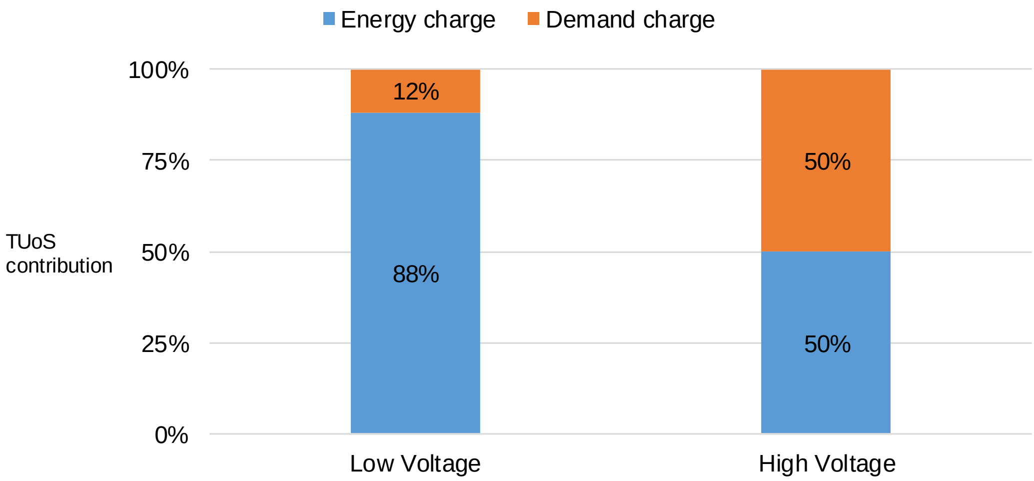
Source: AER analysis

Figure 18-17 above highlights that Evoenergy intends to only moderately re-balance tariffs from a DUoS perspective over the next regulatory control period.

Evoenergy's Transmission Use of System (TUoS) Tariffs

Figure 18-18 shows the annual TUoS revenue share by charging parameter type for the main residential tariffs.

Figure 18-18 Evoenergy - TUoS revenue share by charging parameter 2018/19

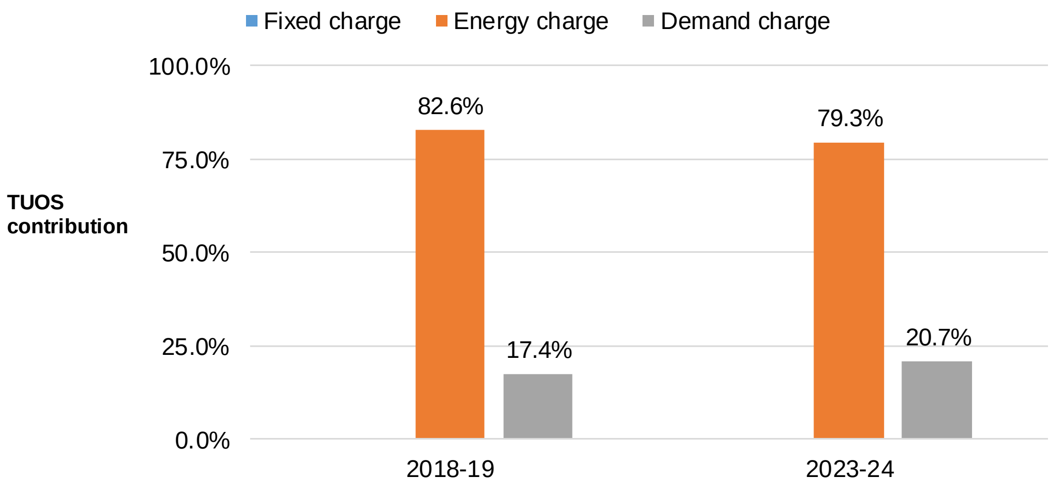


Source: AER analysis

Figure 18-18 above highlights that the TUoS component of Evoenergy's main residential and low voltage commercial network tariffs is predominantly based on energy consumption. As we discuss below on transmission pricing, this approach is not reflective of the costs associated with transmission service provision. We also note that the TUoS component of Evoenergy's high voltage tariff is more cost reflective given the greater reliance on the demand charge. Nevertheless even for customers with accumulation metering installed there is still scope to improve cost reflectivity of these tariffs by increasing the TUoS allocation to fixed charge.

Figure 18-19 compares the TUOS revenue by charging parameter in 2018-19 and 2023-24.

Figure 18-19 Evoenergy - TUoS revenue share by charging parameter



Source: AER analysis

Evoenergy intends to modestly re-balance TUoS revenue away from energy consumption towards the demand charge during the 2019-24 regulatory control period. This is mainly as a result of an expected increase in number of LV-connected customers assigned to the more cost reflective demand tariff over this period.

Insights into the economic efficiency implications of tariff reform proposals

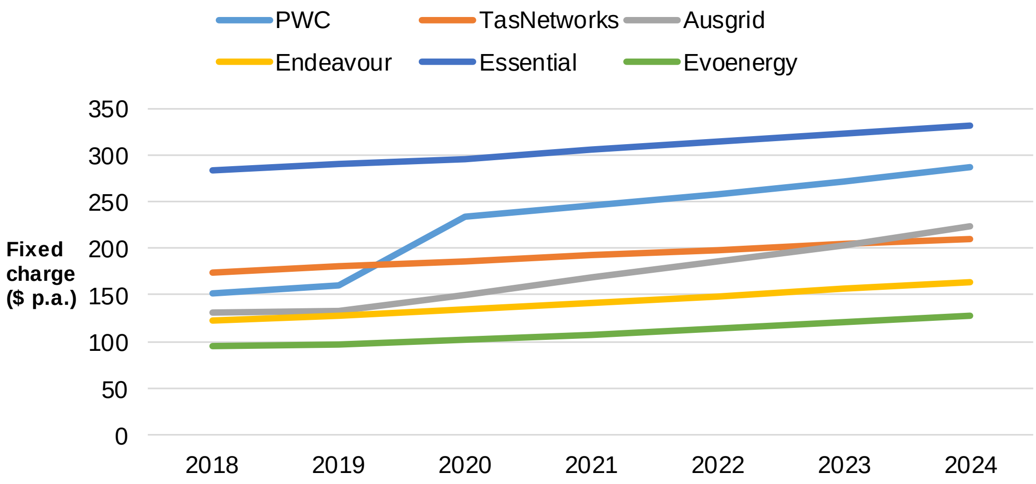
Compliance with the distribution pricing principles in the NER requires that the distributors make progress towards LRMC-based pricing and the efficient recovery of residual costs. We explore these issues below.

Progress towards efficient recovery of residual costs

The efficient recovery of residual costs requires distributors to recover these costs in a manner that minimises the distortion to efficient network usage. The fixed charge is typically an efficient way to recover these costs because changes in the level of the fixed charge do not influence the investment, network connection and consumption decisions of electricity distribution customers.

Figure 18-20 below provides insights into the extent that the DNSPs propose to increase the level of the fixed charge of their residential legacy tariff over the next regulatory control period.

Figure 18-20 Distributor comparison - Annual fixed charges for residential legacy tariff

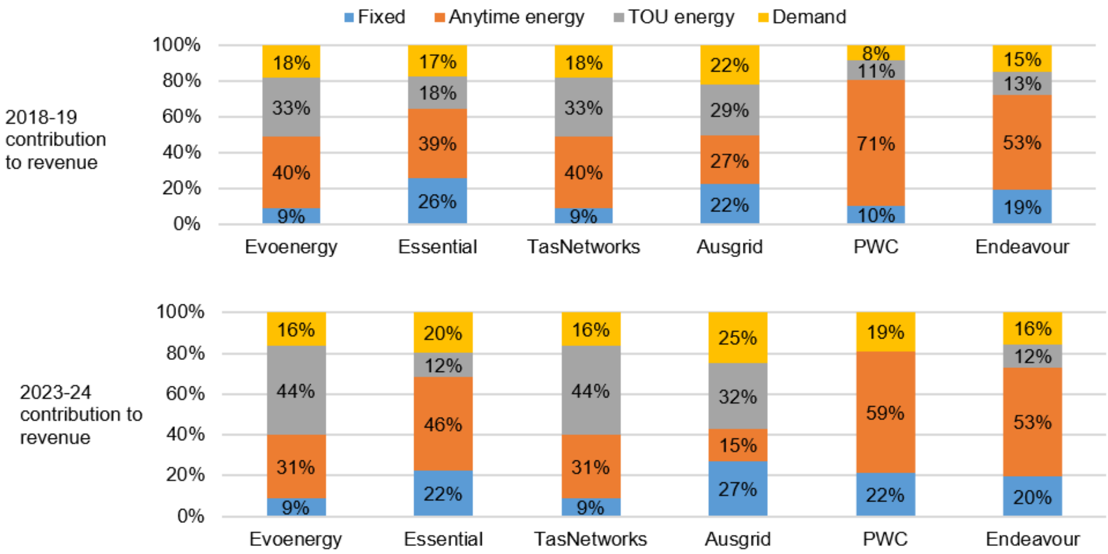


Source: AER analysis of distributors' response to AER information requests

The above comparison reveals that Essential Energy expects to continue to have the highest fixed charge of all the distributors with open regulatory determinations. Notably, Ausgrid and Power and Water propose to increase their reliance on fixed charges, with significant increases in the level of fixed charge expected over the next regulatory control period.

Compared to other distributors, Evoenergy and Endeavour Energy propose to apply only modest increases to the fixed charge over this outlook period.

Figure 18-21 Distributor comparison - Network revenue share by charging parameter



Source: AER analysis of distributors' response to AER information requests

Figure 18-21 above shows that most distributors propose to re-balance their network tariffs away from inefficient anytime energy charges towards more cost reflective demand and fixed charges in the next regulatory control period.

We note there is a considerable variation in the proposed rate of tariff re-balancing across distributors, with Ausgrid expected to have the lowest reliance on anytime energy charges (15 per cent) in 2023-24, whereas Power and Water and Endeavour Energy are expected to have the highest reliance on anytime energy charges in 2023-24 of 59 per cent and 53 per cent, respectively.

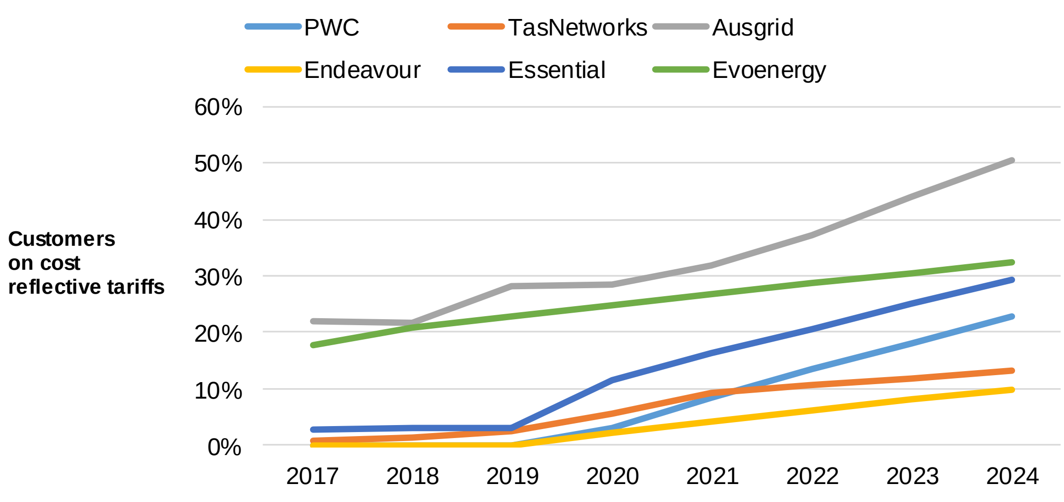
Progress towards LRMC-based pricing

Consistency with the LRMC based pricing aspect to the distribution pricing principles, can be achieved a number of ways, such as:

- transitioning the level of peak charging parameters to LRMC estimates
- reforming the peak charging windows to more accurately reflect times of network congestion
- increasing the number of customers on more cost reflective network tariffs.

Evoenergy proposes to continue to prescribe demand tariffs for new energised connections in the residential and small business customer segment. As a result of this policy, the number of Evoenergy's residential customers on a more cost reflective ToU tariff or demand tariff will grow over the five years to 30 June 2024. Figure 18-22 compares the penetration of cost reflective pricing in residential customer segment by distributor.

Figure 18-22 Proportion of residential customers on cost reflective tariffs



Source: AER analysis of distributors' response to AER information requests

Figure 18-22 above highlights that in 2018 Evoenergy and Ausgrid have the highest penetration of a cost reflective network pricing with approximately 20 per cent and 22 per cent of their residential customer base, respectively, currently assigned to a ToU energy tariff or demand tariff at the network level.

Essential Energy and PWC also expect to make significant progress in the introduction of cost reflective pricing for the residential customer segment over the next regulatory control period. TasNetworks and Endeavour Energy expect to make only gradual progress in the introduction of cost reflective pricing in the residential customer segment over this period.

Retail Electricity Pricing

Generally, all residential and small business energy pricing offers are either a standing offer or a market offer.[56] The key difference between the two is the terms and conditions in the contract, and the resulting price.

In jurisdictions with price regulation, such as Queensland and Tasmania, standing offers also incorporate the jurisdictionally determined price. All retailers must offer standing offer contracts and these are often the 'default' contract when a consumer does not choose a specific market offer.

Market offers tend to be significantly cheaper than standing offers. Most retail energy tariffs for residential and small business customers comprise a fixed charge and a variable energy charge. Most retailers pass on the tariff structures offered by the electricity networks, such as time of use tariff and block tariffs.[57] Some retailers have innovated in the tariff structures that they offer, such as the fixed payment plan offered to residential customers by Origin Energy.[58]

Electricity retail market concentration by jurisdiction

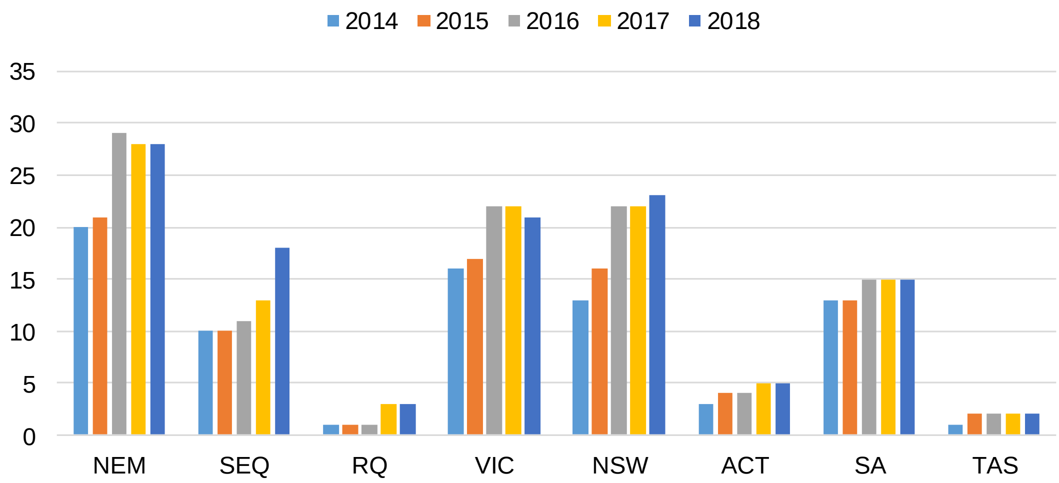
As of March 2018, there were a total of 28 active electricity retailers in the NEM. Tasmania has the least number of active electricity retailers of all regions, see Figure 18-23 below.

[56] Note that small customer definition applying to retail standing offers varies by jurisdiction, ranging from 40 MWh pa in Victoria to 160 MWh pa in South Australia.

[57] Refer to Glossary section for a definition of block tariff and time of use tariff structures.

[58] For more information about this plan refer to the following link: https://www.originenergy.com.au/terms-and-conditions/predictable-plan-terms-and-conditions.html

Figure 18-23 Active electricity retailers in National Electricity Market



Source: AEMC 2018 Retail Energy Competition Review

It is clear from Figure 18-23 above that, compared to the more populous states, there are fewer active electricity retailers operating in Rural Queensland, ACT and Tasmania.

Comparison of retail electricity prices for residential customers by jurisdiction

It is difficult to compare retail electricity prices for residential customers across jurisdictions because of the range of offers that retailers make in deregulated markets. Table 18-17 shows the estimated annual electricity bill (including all discounts) for single rate offers available to residential customers by jurisdiction, as reported on the Energy Made Easy website.[59]

Table 18-17 Comparison of retail electricity prices

Jurisdiction	No. of offers	Price range ($)	Average bill ($)
Canberra	34	1,465 – 2,301	1,590
Sydney	78	1,946 – 3,686	2,221
Brisbane	64	2,147 – 3,515	2,349
Adelaide	69	2,676 – 4,588	2,895

59 Refer to: https://www.energymadeeasy.gov.au/

Jurisdiction	No. of offers	Price range ($)	Average bill ($)
Melbourne	273	1,150 – 2,510	1,831
Hobart	1	2,284	2,284
Perth	N/A	N/A	N/A

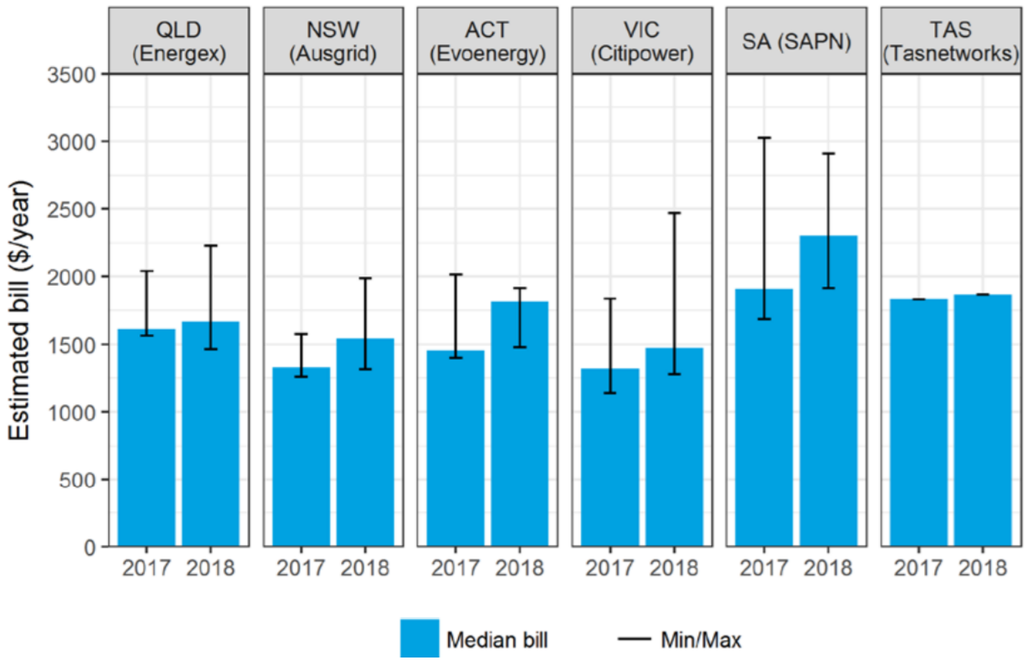
Note: Bill calculation based on prices as 22 February 2017 and a customer using 7,500 kWh per annum.

Source: ICRC 2017

The table highlights that the annual electricity bill for a residential customer varies considerably across jurisdiction, both in terms of the average bill amount and the spread of pricing offers available.

Figure 18-24 below provide a comparison of the medium electricity retail bill between 2013 and 2017 under the standing offer for a typical residential and small business customer by jurisdiction. It is clear from this figure that standard offer became more expensive over this time period in all jurisdictions, except Tasmania. The other insight is the diversity in the level of standard offers within jurisdictions such as Victoria and South Australia.

Figure 18-24 Median electricity residential retail standing offer by region



Source: AEMC, *2018 Retail Energy Competition Review, Final Report*, 15 June 2018 p. 72

Retail electricity market in the Australian Capital Territory

All residential and business customers in the ACT have the choice of staying with ActewAGL and negotiating a market retail contract or negotiating a market retail contract with another authorised retailer. Small customers that choose to not negotiate a market retail contract will be assigned to ActewAGL regulated standard offer tariff. The Independent Competition and Regulatory Commission (ICRC) determines the maximum price that ActewAGL can charge its regulated customers.

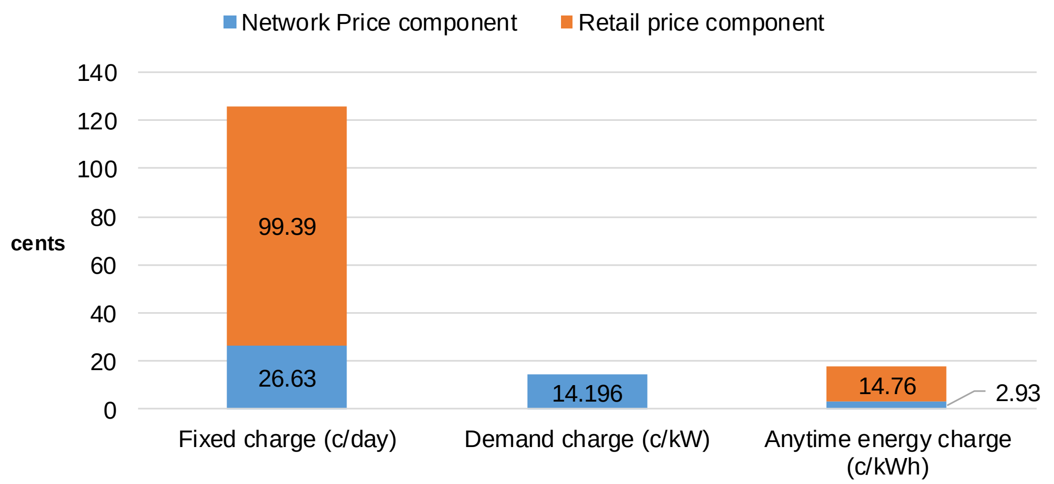
The ACT market remains highly concentrated despite having introduced full retail contestability. As with Tasmania, retail price regulation and the small size of the market continue to be barriers to entering this market. Despite Origin Energy entering the ACT market in September 2014, ActewAGL remains the dominant retailer for both electricity and gas in the ACT, supplying over 90 per cent of customers. Approximately 77 per cent of small customers in the ACT remain on its regulated standing offer tariff.[60]

Retail pricing behaviour in the ACT

The underlying network tariff structure is typically reflected in ActewAGL standard retail tariffs for residential and small business customers (less than 150 MWh pa).

It is important to note that ActewAGL offers a standard retail demand tariff offer to residential and small business customers. As highlighted in Figure 18-25 below, the retail tariff structure reflects the underlying Evoenergy network tariff structure. Importantly, ActewAGL did not apply a retail mark-up to the network demand charging parameter, resulting in the retail costs only being recovered through the fixed charge and the anytime energy charging parameter.

Figure 18-25 ActewAGL Smart Meter Home Demand Tariff



Source: AER analysis

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60 AEMC, *Residential Electricity Price Trends*, 18 December 2017

The only exception is the Home Saver Tariff where the network tariff comprises a single anytime energy charge, whereas the retail tariff is comprised of a two block inclining anytime energy charge.

B Tariff design and assignment policy principles

Under the National Electricity Rules, the objective of tariff reform is to introduce cost reflective pricing.[61] Tariff design and assignment policy has a role in achieving this objective by influencing:

- how efficiently the tariff structures actually target customers that are driving network costs and
- the speed with which customers take up cost reflective tariffs and which customers move to cost reflective tariffs.

In our assessment of a distributor's proposed tariff structure statements, we consider the pricing principles and the network pricing objective within the National Electricity Rules when determining to approve the statements.

The pricing principles include two complementary principles to economic efficiency that can be summarised as the customer impact measures:

- we must consider customer impacts of the transition towards cost reflective pricing[62]
- we must contemplate whether customers are going to be able to understand the charges they are likely to see.[63]

In other words, cost reflective pricing can be departed from in circumstances where doing so will promote the achievement of these two additional principles. In this appendix, we outline the AER's policy positions on tariff design and assignment policy. We have structured the appendix as follows:

1. In what circumstances should distributors assign, or reassign, customers to a new tariff?
2. When a distributor assigns or reassigns a customer to a new tariff, what options should the customer, or retailer as the customer’s agent, have to change to optional tariffs?
3. What tariffs should a distributor offer to customers, and which customers should have access to which tariffs?
4. Should any aspects of tariff design and assignment be consistent nationally, within a state or within a city?

[61] NER cl 6.18.5(a).
[62] NER 6.18.5(h).
[63] NER 6.18.5(i).

When should tariff assignment happen?

Distributors charge retailers network tariffs for each class, or type, of customer. Customers can be households, low voltage or high voltage commercial, or sub–transmission users connected to the high voltage network. Each can face a different network tariff structure and charge.

A distributor's tariff assignment policy are the rules the distributor follows to allocate network tariffs to customers. The AER regulates distributors' tariff assignment policies when we approve tariff structure statements, which must contain such policies.

Tariff assignment is when, in accordance with its approved tariff structure statement, the distributor decides what tariff to apply to a new customer (i.e. a new connection).[64]

In contrast, tariff reassignment is when the distributor switches an existing customer from one tariff to another tariff.

We consider that distributors should:

- Assign new customers to cost reflective tariffs upon initial connection, which would include a smart meter under current contestability rules
- Reassign established customers who upgrade their connections through either
    - adding embedded generation or
    - upgrading to three-phase power
- to cost reflective tariffs upon completing the connection upgrade
- Reassign established customers who receive a new smart meter as part of a retailer's meter replacement programme, 12-months after receiving that smart meter.

This approach balances the need to transition towards cost reflective tariffs with the impact a change in tariff structure might have on customers' ability to control their bills and engage in the electricity market for their long-term benefit. It recognises that customer support for distributors' tariff strategies is an important element of fostering and maintaining users' support for tariff reform generally.[65] If distributors adopt the same (re)assignment triggers there will be a more regular and consistent pace of tariff reform across distributors and jurisdictions.

[64] Retailers are not obliged to pass through network tariffs or network tariff structures to customers in their electricity bills.

[65] NER 6.18.5.

New customers should face cost reflective tariffs

When new customers connect to the distribution network, the distributor should assign them a cost reflective tariff immediately. Each distributor, except TasNetworks, proposed to assign new customers to cost reflective tariffs in this manner.[66]

We consider that it is appropriate for distributors to assign new customers immediately to cost reflective tariffs for the following reasons:

- such tariffs incentivise efficient use of the network[67] and investment in energy efficiency in the construction of a new building/premise[68]
- new connections have no prior tariff, therefore there is no risk of these customers seeing an increase in their network charges (because they never had any to begin with)

Upgrading customers should face cost reflective tariffs

Existing customers may decide to upgrade their electricity connection by:

- installing embedded generation, such as rooftop solar
- increasing the capacity of their connection, such as installing three-phase power.[69]

Distributors can reasonably expect customers that upgrade their connections to understand that the upgrade will impact their network charges. These customers, along with the businesses installing rooftop solar and three-phase power, are in a position to understand the impact of a cost reflective tariff on their network charges. Put another way, they are in a position to appreciate that their decisions will have costs for the network—tariffs should recoup those costs from those same customers.

All TSSs that proposed reassignment to cost reflective tariffs included reassigning customers that upgrade their connections to cost reflective tariffs (see Table 18-18).

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66 Australian Energy Regulator, *TasNetworks Distribution and Transmission Determination 2019 to 2024*, Issues Paper, March 2018, p 38; Australian Energy Regulator, *Evoenergy Distribution Determination 2019 to 2024,* Issues Paper, March 2018, p 33; Australian Energy Regulator, *Power and Water Corporation Distribution Determination 2019 to 2024,* Issues Paper, March 2018, p 35; Australian Energy Regulator, *NSW electricity distribution determinations Ausgrid, Endeavour Energy, Essential Energy 2019 to 2024,* Issues Paper, June 2018, p. 60.

67 See D.4.1.

68 For example, in NSW new residential dwellings must obtain a BASIX certificate to demonstrate that the building complies with energy efficiency standards. Although BASIX does not target peak demand, complying with its energy targets should lead to some reduction in peak demand. NSW Government, *BASIX,* https://www.planningportal.nsw.gov.au/planning-tools/basix

69 We consider this to be a material change to connection arrangements.

Table 18-18 Distributor's proposed reassignment triggers

	New meter	Embedded generation	3-phase power	Batteries	Electric vehicles
Ausgrid	✓				
Endeavour Energy		✓	✓		
Essential Energy	✓	✓	✓	✓	✓
Evoenergy	✓				
Power and Water	✓				
TasNetworks	TasNetworks proposed opt-in tariff reassignment				

We note that the Australian Energy Market Commission's metering rules state customers that upgrade to embedded generation or three-phase power will receive a new meter. Therefore, they are automatically captured under the 'new meter' trigger.

A 12-month delay is appropriate for meter replacements

Under the Commission's tariff reforms, metering providers must replace faulty accumulation meters with smart meters—this is automatic without any action by customers on their behalf.

Under the National Electricity Rules, we consider that customers who receive a new smart meter should face cost reflective tariffs when they can understand those tariffs and influence their charges through their usage decisions.

For new connections and upgraded connections, the customer is engaging with its electricity supply and therefore is positioned to understand cost reflective tariffs.

However, for those that receive a new smart meter on account of their accumulation meter being faulty, these customers are not actively engaging with their electricity supply. Circumstances beyond their control are impacting their connection. We do not consider such customers can necessarily understand the impact of a cost reflective tariff immediately. Therefore, a distributor should only reassign these individuals after expiration of a 12-month sampling period. This delay will assist customers to better understand their load characteristics and be provided sufficient information to make an informed decision when selecting a retail pricing offer.

The 12-month grace period is to help customers to understand a full year of their consumption and demand profile (i.e. so they understand their demand characteristics in all seasons). This will help them adjust to the new cost reflective tariff to which they will be reassigned following conclusion of the grace period.

Retail price regulation will influence tariff reassignment

In some jurisdictions, such as Tasmania and the Northern Territory, there is retail regulation. Retail regulation is a relevant consideration in our decision on acceptable reassignment practices.

In the Northern Territory, the Government caps and subsidises flat retail electricity tariffs. The retailer faces cost reflective tariffs from the distributor but converts these to a flat tariffs for customers under the regulatory arrangements in the Territory. This situation supports the more aggressive approach to tariff (re)assignment proposed by Power and Water Corporation. That's because there is no customer impacts or change to customer understanding that need to be considered following reassignment.

Should customers choose their network tariffs?

In our 2017 Tariff Structure Statements final decision, we indicated that distributors should propose default assignment to cost reflective tariffs in 2019.[70]

Each distributor, except TasNetworks, proposed default assignment to cost reflective tariffs in the Tariff Structure Statements we received in the first half of 2018.[71]

With default assignment to cost reflective tariffs, distributors need to consider whether to offer customers optional tariffs, and which tariffs they should offer. Broadly, we see three possibilities (all derived from Tariff Structure Statements proposals we received in 2018):

- Opt-out to anytime tariffs – where customers can opt-out to anytime network tariffs from the default tariff the distributor assigned them.
- Prescribed tariff assignment – where customers must remain on the default network tariff the distributor assigned them. This is also known as mandatory tariff assignment.
- Choice of cost reflective tariffs– where customers can choose between a suite of alternative cost reflective tariffs (but not anytime tariffs) instead of the default tariff the distributor assigned them.

We consider that distributors should adopt cost-reflective choice because:

- Allowing customers a choice of tariffs allows greater management of customers' ability to understand tariffs and mitigate cost impacts
- Anytime tariffs are not cost-reflective and should not be available to customers that have been (re)assigned (as we discussed above).

Anytime tariffs are not cost reflective

Opt-out to anytime tariffs are popular with customers and retailers.[72] They give the retailer the ability to face flat energy charges. These charges are easy to understand

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70 Australian Energy Regulator, *Tariff structure statements Ausgrid, Endeavour and Essential Energy,* Final Decision, February 2017, pp. 60–61.

71 We note that Ausgrid's proposed to assign customers with usage under 2MWh to inclining block anytime energy tariffs.

72 Anytime tariffs, are any form of tariff where the network charge is not dependent on the time of usage or demand, common forms include flat tariffs, inclining block tariffs and declining block tariffs.

and manage for customers.[73] However, they do not reflect the cost drivers of the distribution business. That is, they charge customers the same amount per unit of electricity transported during peak and off-peak periods. This signals too much usage during the peak, and insufficient amounts in off-peak, potentially requiring unnecessary investment that can drive up network costs. That's not in the long term interest of customers.

The capacity of the distribution network is a significant driver of network costs. Therefore, the main determinant of how much cost customers are imposing on the network is how much they demand when the network, in their geographic area, is approaching its capacity constraints. Demand tariffs and time of use tariffs target time periods where capacity constraints are more likely to occur.

We consider that distributors should no longer offer customers who are on a cost reflective tariff the ability / option to opt-out to anytime energy network tariffs. The risks of allowing continued access to anytime tariffs – inefficient use of, or investment in, the network – outweigh the benefits of customers understanding these simple tariff structures.[74] After all, this represents nothing more than continuation of the status quo, acknowledged by policy makers as inappropriate. We note retailers can continue to offer anytime energy retail tariffs when facing cost reflective network tariffs.

Some State and Territory Governments have imposed retail regulation that requires retailers to offer anytime tariffs. In these States and Territories, removing anytime network tariffs means retailers will see a mismatch between their revenues (achieve from customers on flat *retail* tariffs) and their costs (paying cost reflective *network* tariffs for those same customers). If retailers are unable to convince customers facing flat *retail* tariffs to change their consumption habits, the cost reflective *network* tariffs will not drive lower network costs.

At the same time, the mismatch between revenue and costs could lead State and Territory regulators to permit retailers a higher retail margin to compensate retailers for the additional risks.[75] Where there is a significant risk of this happening, we consider that we have little option but to continue to allow customers to opt-out to flat network tariffs while the retail price regulation applies.

The ACCC supported prescribed tariffs

The ACCC recommended, in its Retail Electricity Pricing Inquiry, prescribed tariff assignment, ending opt-in and opt-out tariff assignment (including cost reflective choice). To mitigate the potential negative impacts, the ACCC recommended governments provide transitional assistance, including:

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73 NER 6.18.5(h) and 6.18.5(i).

74 That is, the costs of the lost opportunity for cost reflectivity (NER 6.18.5(a)) outweigh the benefits of customer acceptance and understanding (NER 6.18.5(i)).

75 The mismatch could also lead retailers to come up with other options to encourage customers to change their consumption. However, to date we have not seen such innovations.

- A compulsory data sampling period for customers following smart meter installation; this is the approach we have recommended in section 18.4.1.2 above
- A requirement for retailers to offer flat energy retail tariffs to customers that distributors charge more cost reflective network tariffs
- Additional targeted assistance for vulnerable customers.

Stakeholders should consider the ACCC's final recommendations in its Retail Electricity Pricing Inquiry as a package of recommended changes to the existing requirements of the NEL and the NER. In contrast, the AER's current task is to apply the existing network regulatory framework (in chapter 6 of the NER) within which we are reviewing the current tariff structure statement proposals.

For example, in most parts of the national electricity market there is no requirement for retailers to offer flat retail energy tariffs, and we are not aware of any additional targeted assistance for vulnerable customers. This means we cannot impose these requirements on retailers through our approval of distribution network service providers' tariff structure statements. We consider that, without the complementary measures the ACCC proposed as part of the package it recommended, prescribed tariff assignment has shortcomings. As noted above, in our review we are looking at what distributors can do on their own.

Firstly, removing customer's choice through prescribed tariff assignment risks the loss of customer support. This is particularly likely if retailers do not decide to offer customers flat energy tariffs or innovative tariff designs that are easy to understand and lower risk to end-users. In its work for the ACCC, the CSIRO found that most retailers pass on the structure of cost reflective tariffs to end-users, this would mean these customers have very little choice in the tariffs available to them.[76]

Secondly, prescribed tariff assignment leads to the need for a one-size fits all approach. This means that the prescribed tariff would need to be understandable for all customers and manage the impacts for all customers

Prescribed tariff assignment on the other hand may lead to a lowest common denominator approach to tariff reform, potentially slowing the transition to cost reflective tariffs.

In spite of our concerns, we consider that coupled with complementary measures, prescribed tariff assignment can work. In the Northern Territory, Power and Water Corporation proposed a prescribed assignment policy for residential customers.[77] However, as noted earlier, the Northern Territory Government regulates and

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[76] Australian Competition and Consumer Commission, *Restoring electricity affordability and Australia's competitive advantage*, Retail Electricity Pricing Inquiry Final Report, June 2018, p. 178.

[77] Power and Water Corporation, *Tariff Structure Statement,* Proposal, 16 March 2018, p. 18.

subsidises retail electricity prices.[78] This means that the move to prescribed assignment is highly unlikely to come at the cost of customer support for reform, to reduce customer choice or increase retail prices.

Customers should have choice in cost reflective tariffs

Default assignment to cost reflective tariffs, with optional alternative cost reflective tariffs available, will lead to a fast adoption of cost reflective tariffs. Indeed, it may lead to a faster adoption of cost reflective tariffs than prescribed tariff assignment, as:

- the default tariff under this approach may be more cost reflective than the prescribed tariff
- it allows for more cost reflective optional tariffs–such as critical peak pricing or rebates–that could build customer acceptance and retail offerings that support a wider rollout of these more cost reflective tariff structures.

We note that the ACCC expressed concerns about an opt-out to cost reflective tariff approach. Stating:

> An alternative form of phased approach would be to introduce cost reflective tariffs at both the retail and network level to all customers on a trial basis so that they can gauge their appropriateness. Customers could then be given the opportunity to move to a less cost reflective retail and network tariff structure without penalty if desired (a delayed opt-out approach)…. The ACCC considers that such an approach would not be ideal as it would delay the benefits from greater cost reflectivity, but it may be a workable option if used only for a short time period.[79]

The ACCC's statement reflects the fact that its recommendation is part of a package of reforms.

We consider that by allowing choice between different cost reflective tariffs there is a lower risk of losing customer support for tariff reform. Even where retailers pass through network tariff structures, customers will have a choice on what tariff they face. cost reflective choice arrangements would create the opportunity for customers to select:

- tariffs they can understand.
- transitional tariffs that reduce the immediate impact of tariff reassignment, allowing vulnerable households to adjust to new tariff structures.
- more cost reflective tariffs that are not understandable to the wider customer base but nevertheless benefit customers with elastic and responsive demand, or

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78 Electricity Pricing Order under section 44(8) of the *Electricity Reform Act (NT)* in accordance with 13A9d) of the *Electricity Reform (Administration) Regulations,* 6 June 2017.

79 Australian Competition and Consumer Commission, Restoring electricity affordability and Australia's competitive advantage, Retail Electricity Pricing Inquiry Final Report, June 2018, pp. 185–186.

facilitate innovative retail offers such as peak demand reduction rebates or retailer owned demand management technologies.

This approach has been utilised by Evoenergy since December 2017.[80] Essential Energy also proposed this approach for customers with new technology.[81]

These approaches best balances the need for cost reflective tariffs and engendering customer support for tariff reform through managing impacts and customers' ability to understand tariffs under the existing regulatory framework.

What tariffs should distributors offer?

In this section, we consider what tariffs distributors should offer to customers. We make this recommendation in the context of our finding in D.2, that distributors should offer customers a portfolio of cost reflective tariffs. We will focus on tariffs for residential and small business customers, unless otherwise indicated.

We recommend that distributors offer customers:

- Time of use energy tariffs – these tariffs are as cost reflective as any other more average tariff with a pre-defined peak period and are well understood by customers.
- Demand tariffs – these tariffs are as cost reflective as any other more averaged with a pre-defined peak period and reinforce with customers that demand is an important cost driver. We consider that distributors with a dominant peak season should aim to offer seasonal monthly demand tariffs with flat energy charges and distributors without a dominant season should aim to offer monthly demand tariffs with time of use energy charges.
- Highly cost reflective tariffs for large business customers – large business customers are well informed and spend large amounts of money on electricity, therefore distributors can assume that they understand highly cost reflective tariffs.
- Flat tariffs for customers with accumulation meters – the technological limitations of accumulation meters require anytime tariffs, which are easier to understand and are slightly more cost reflective than inclining block tariffs.

We will also support distributors offering residential and small business customers:

- Optional location based critical peak prices – these are the most cost reflective tariffs, however can be difficult to understand. Allowing customers (or their retailers) to opt-in to these tariffs will allow customers that can understand these tariffs to use and benefit from them.

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80 ActewAGL, *Revised Tariff Structure Statement,* Overview Paper, 4 October 2016, p. 18.

81 Essential Energy, *2019-24 Tariff Structure Statement,* Proposal, April 2018, p. 25.

- Optional transitional tariffs – transitional tariffs can reduce the impacts of being assigned to cost reflective tariffs. They may be valuable to some vulnerable customers who need time to adjust how and when they use electricity.

In this section, we:

- Discuss what makes a tariff cost reflective
- Assess time of use energy tariffs
- Assess demand tariffs
- Consider the role for transitional tariffs
- Identify opportunities for a greater role for more highly cost reflective tariffs
- Identify opportunities for introducing innovative network tariffs
- Consider what tariffs distributors should offer customers with accumulation meters, and
- Identify appropriate tariff structures for large business customers.

Efficient tariffs align with cost drivers

An efficient tariff sends a signal to the customer on what the customer's electricity demand costs the distributor. Under long-run marginal cost pricing, the signal should reflect the costs of the customer sustaining its behaviour over the long run. For example, when a customer buys a larger air conditioning system its electricity usage and demand will increase during hot days, the distributor's tariffs should equal the costs of using that air conditioner on hot days to the customer.

We have heard from stakeholders that 'demand issues require a demand charge and energy issues require an energy charge'. This position has an appealing simplicity. Unfortunately, it does not reflect reality.

Distribution businesses can indeed face two types of issues:

1. Demand issues are situations where capacity is driving network costs. Distributors typically experience demand issues when people get home from work on the hottest days and turn on their air conditioners or coldest days and turn on their heating, while transport systems and businesses are still operating at or near full capacity.
2. Energy issues are situations where electricity usage is driving network costs. This includes any costs created by insufficient electricity usage.

Customer demand and energy usage are closely related. A customer that sustains a demand of 1kW of electricity for one hour will use 1kWh of electricity.

At a residential and small business level, distributors see demand constraints based on coincident demand. (That is the total demand from customers within the feeder zone.)

Distributors have proposed two approaches to increase the cost reflectivity of their residential and small business tariffs:

- Demand tariffs where distributors charge customers based on their maximum 30 minute demand during peak hours each month, and
- Time of use tariffs where distributors charge customers based on their total electricity consumed during peak hours.

Based on our analysis of data provided by NSW distributors, we consider that there is no clear cost reflective advantage of adopting demand tariffs over time of use tariffs. The method and results of our analysis are summarised in Box A below.

Box A Cost reflectivity of demand and time of use tariffs

The NSW distributors provided the AER with {one-year} of smart meter data for a sample of their customers (ranging from 240 to 5,000 individual customers). Using this smart meter data, we calculated each individual customer's demand during the top 80 30-minute periods (that is the 40 hours of greatest system demand) (a proxy for an efficient tariff)[82]

We calculated how much energy usage or demand would be charged under different tariff structure options:

- flat energy charges
- time of use tariffs – both annual and seasonal
- demand tariffs – including permutations of demand charges calculated daily, monthly, annually and top 5 demands per month on anytime, peak and seasonal peak bases, with flat and time of use energy charges.

We estimated how well the components of the tariffs can predict customers' usage during the peak, using linear regression of tariff components and analysing the predicted R2 of the regressions. We found that:

- seasonal tariffs outperform annual tariffs
- time of use tariffs and demand tariffs perform similarly
- demand tariffs with energy charges outperform demand tariffs without energy charges (time of use energy charges typically complement demand charges better than flat energy charges)
- monthly demand charges outperform daily demand charges.

[82] In 2013, the Productivity Commission estimated that 25% of retail electricity bills in NSW reflect the cost of system capacity that is used for less than 40 hours a year. PC, Electricity Network Regulatory Frameworks, 9 April 2013, p. 337.

Time of use tariffs are easy to understand

Time of use energy tariffs apply different charges to electricity consumption, in kWh, at different times of the day, week, and year. Distributors split days into two or three periods:

- peak – timed to correspond with the parts of the day most likely to see demand approach system or zonal capacity constraints,
- off-peak – timed to correspond with the parts of the day least likely to see demand approach system or zonal capacity constraints, and in some cases
- shoulder – timed to correspond with the parts of the day with either a small chance of approaching a system capacity constraint or likely to see a demand approach capacity constraints in some small substation zones.

Distributors often remove peak charges from days unlikely to see system or zonal peaks, such as:

- weekends – where business demand is reduced
- public holidays – where business demand is reduced, and
- low demand seasons – where due to reduced air conditioning or heating use by customers reduces the probability of a demand approaching capacity constraints.

Customers are familiar with distributors charging them based on how much electricity they consume. Distributors charge customers with accumulation meters based on their energy consumption, and time of use energy tariffs are well established. In general, we consider that customers will be able to understand time of use energy tariffs. We also note that time of use energy tariffs can be relatively efficient, in that peak consumption is correlated with user demand during coincidental peaks.[83]

The residential time of use energy tariff designs proposed by distributors are summarised in Table 18-19 below.

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[83] This is based on our analysis of NSW distributors' interval meter data. We found that Ausgrid's proposed seasonal time of use energy tariffs were the most cost reflective of all tariffs proposed by NSW distributors for residential customers.

Table 18-19 Proposed residential time of use energy tariff designs

Distributor	Description	Ratio of peak to off-peak (2023-24)
TasNetworks	7am to 10am and 4pm to 9pm peak on weekdays year-round with all other times off-peak.	4.9
Evoenergy	7am to 9am and 5pm to 8pm peak everyday year-round, 9am to 10pm shoulder period (excluding peak period) with 10pm to 7am off-peak.	3.2
Ausgrid	2pm to 8pm weekday peak from November to March, 5pm to 9pm weekday peak from June to August, of 7am to 10pm weekday shoulder period (excluding peak period) year-round, with all other times off-peak.	9.5
Essential Energy	5pm to 8pm weekday peak year-round, shoulder period of 7am to 10pm weekdays (excluding peak period) year-round, with all other times off-peak.	3.3

We consider that the different proposals are likely to exhibit different levels of cost reflectivity and customer understanding, based on their designs. We consider:

- More cost reflective tariffs will have more targeted peak periods. The Ausgrid proposal does this by tailoring the peak period in summer and winter, and not including peak charges during the milder spring and autumn periods.
- Easier to understand tariffs are simple for customers to remember. The Essential Energy proposal does this by having a single peak period year-round, which makes it easy for customers to remember when peak charges apply and change their behaviour accordingly.

We consider that these differences are acceptable. They largely reflect:

- the difficulties in constructing a cost reflective tariff (e.g. Essential Energy's system covers a wide range of climates and different substation zones will approach capacity constraints at different times of the year), and
- current levels of customer acceptance of time of use tariffs (e.g. Ausgrid currently has 330,000 customers with on time of use energy tariffs)[84].

However, we recommend that as customer acceptance of time of use energy tariffs increases distributors should increasingly include highly targeted peak windows.

Highly targeted peaks should be narrow and seasonal. LRMC prices are the probability of the constraint occurring within a peak/shoulder/off-peak period, divided by the total number of hours in that peak/shoulder/off-peak period. Narrow, more targeted, peak periods will require distributors to increase the peak period charges and decrease shoulder and off-peak charges (increasing the ratio of peak to off-peak charges). This will send stronger and more efficient conservation signals to customers, which should lead to efficient reductions in capital expenditure over the long term.

[84] Ausgrid, *Tariff Structure Statement*, Proposal, April 2018, p. 8.

We consider time of use energy tariffs are sufficiently cost reflective to be approved as default tariffs.

Demand tariffs can be cost reflective

Demand tariffs charge customers based on the maximum point in time demand (typically over a 30-minute period) in kW or kVa, typically on a daily or monthly basis. Demand tariffs help cost recovery be in proportion to the network capacity customers' use. The demand charge can be:

- Anytime demand – where the charge is the maximum 30-minute demand at any point in the day or month
- Peak demand – where the charge is the maximum 30-minute demand during a pre-defined peak period during the day or month[85]
- Time of use demand – where the charge is the maximum 30-minute demand during each of the pre-defined peak, off-peak and shoulder periods, during the day or month.[86]

The ACCC's Retail Electricity Pricing Inquiry found that 'demand tariffs represent a good balance of cost reflectivity, simplicity and price stability':

- Simplicity –the 'two-part tariff' structure (demand and energy usage) is broadly similar to current tariff structures.
- Cost reflectivity –while the individual's peak demand may not coincide with the network peak it emphasises to customers the relationship between network cost and demand, rather than with usage.
- Price stability –demand charges would lead to more stable customer bills than more cost reflective options, such as critical peak pricing.

We will accept distributor's proposals to assign residential and small business customers to demand charges by default due to their level of cost reflectivity.

The residential demand tariff designs proposed by distributors are summarised in Table 18-20.

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[85] Evoenergy proposed a peak demand charge for customers with smart meters. Source: Evoenergy, *Regulatory proposal for the ACT electricity distribution network 2019–24 – Attachment 17: Proposed Tariff Structure Statement,* January 2018, pp. 1–2.

[86] Essential Energy proposed a time of use demand charge for large business customers. Source: Essential Energy, *2019-24 Tariff Structure Statement*, Proposal, April 2018 pp. 31–33.

Table 18-20 Proposed demand charges

	Demand charge	Other charges
Endeavour Energy	Maximum monthly demand between 4pm and 8pm on weekdays, with a higher demand charge from November to March.	Fixed charge and a flat energy charge.
Essential Energy	Maximum monthly demand between 7am and 10pm on weekdays.	Fixed charge and a time of use energy charge.
Evoenergy	Maximum daily demand between 5pm and 8pm every day.	Fixed charge and a time of use energy charge.
Power and Water	Maximum monthly demand between midday and 9pm from October to March.	Fixed charge and a flat energy charge.
TasNetworks	Maximum daily peak and off-peak demand, with the peak between 7am to 10am and 4pm to 9pm weekdays.	Fixed charge.

In our 2017 final decisions on tariff structure statements, we expressed concern with residential demand charges based on a customer's demand over a month or longer. We noted that it is not an individual customer's monthly peak demand that drives network costs, but to the extent which that customer's demand contributes to network congestion near capacity constraints.[87] As above, the ACCC also made this observation.

The NSW distributors provided the AER with interval meter data. Using this data, we tested the correlation between individual customers demand during the top 40 hours each year, and compared it to the same customers:

- monthly maximum 30-minutes demand (within the distributor's proposed peak charging window) as proposed by Endeavour Energy, Essential Energy, and Power and Water Corporation,
- daily maximum 30-minutes demand (within the distributor's peak charging window), as proposed by Evoenergy and TasNetworks, and
- annual maximum 30-minutes demand (within the distributor's peak charging window) as proposed by Ausgrid.

We found that monthly maximum demand was the best performing demand charge. We also found:

- demand tariffs perform better with embedded energy charges
- seasonal demand tariffs are more cost reflective where a large majority of regions in the network area peak in the same season.

We consider that there are benefits of both forms of energy charges distributors have proposed to use within their demand tariffs:

87 Australian Energy Regulator, *NSW electricity distribution determinations Ausgrid, Endeavour Energy, Essential Energy 2019 to 2024,* Issues Paper, June 2018, p. 140.

- Flat energy charges – are easier for customers to understand, which may lead to greater customer acceptance of demand charges, while maintaining a peak conservation signal through the demand parameter.
- Time of use energy charges – send stronger conservation signals and will recover a greater proportion of residual costs during peak periods, reducing customers' ability to avoid paying for residual costs through embedded generation. We have found that demand tariffs with time of use energy tariffs can better reflect customers' demand during system peaks.

Our analysis finds that demand tariffs without energy charges do a worse job of reflecting customers' demand during system peaks than flat tariffs.

We consider that combining seasonal monthly demand charges, with seasonal time of use energy charges is overly complicated. These tariffs may not be well understood by customers. Therefore, we consider, at this stage of tariff reform, the most appropriate demand tariffs are:

- Seasonal monthly demand tariffs with flat energy charges where a distributor has a dominant season, and
- Monthly demand tariffs with time of use energy charges where a distributor does not have a dominant season.

We consider demand tariffs are sufficiently cost reflective to be approved as default tariffs.

Distributors should design transitional tariffs for vulnerable customers

Ausgrid and Endeavour Energy have both proposed transitional tariffs. Distributors design transitional tariffs to smooth the impact of moving from flat tariffs to more cost reflective tariffs over a longer time-period. Distributors should design transitional tariffs to assist vulnerable customers that may need time to adjust to cost reflective pricing.

We consider that distributors should offer transitional tariffs on an optional basis, if they consider the impacts of cost reflective tariffs too great in the short-term. Transitional tariffs:

- Reduce the efficiency of price signals to customers
- Potentially lead to annual changes in price levels for retailers to explain, and
- Are typically more expensive for around half of all customers.

Default tariff assignment should be to cost-reflective tariffs.

Location based pricing has significant advantages

In the current environment, we consider that time of use energy tariffs and demand tariffs best balance cost reflectivity[88] and customers' ability to understand tariffs[89] for the broad range of customers facing default tariff assignment. However, there are ways to make tariffs more cost reflective, including:

- Narrow the peak - in 2013, the Productivity Commission found that in NSW peak demand events occur for less than 40 hours per year and are the key driver for network costs.[90] By comparison, Endeavour Energy's proposed demand charge would cover over 1,000 hours a year,[91] and Ausgrid's seasonal peak time of use energy tariff would cover over 800 hours a year.[92]
- Vary by location – distribution networks are made up of many feeder and substation zones. Each zone has its own capacity (or rating), with different load profiles and climates. Therefore, varying tariffs by location can better target the times and locations to signal conservation, indeed in areas with high excess capacity it may be more efficient to encourage usage.

The NER's pricing principles include a principle that distributors must base tariffs based on long run marginal cost, including consideration of:

- Times of greatest utilisation of the relevant part of the distribution network,[93] and
- The extent to which costs vary between different locations.[94]

Therefore, if distributors were to propose critical peak pricing or prices that vary by location, there is scope for the AER to approve a tariff structure of this kind.

The need for innovative tariffs depends on retailers

There exists numerous alternative tariff designs that distributor could propose designed to increase cost reflectivity, while managing customer's ability to understand tariffs. Two of these approaches are:

- Demand subscription tariffs where customers select the maximum level of demand they will use during peak hours, but face extra charges for exceeding this limit, similar to a mobile phone plan.[95] Energex and Ergon Energy are both offering

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88 NER 6.18.5(e)(f) and (g).

89 NER 6.18.5(i).

90 Productivity Commission, *Electricity Network Regulatory Frameworks,* 9 April 2013, p. 16.

91 Assuming 260 working days a year and Endeavour Energy's proposed demand charges would apply for 4-hours a day on working days.

92 Assuming 90 working days between November and March, and 65 working days between June and August (inclusive) and Ausgrid's proposed peak time of use energy charges would apply for 6-hours in the summer period and 4-hours in the winter period.

93 NER 6.18.5(f)(2).

94 NER 6.18.5(f)(3).

95 Brown, T., Faruqui, A., Lessem, N.,, *Electricity Distribution Network Tariffs – Principles and analysis of options prepared for The Victorian Distribution Businesses,* Brattle Group, April 2018, p 48.

energy subscription 'lifestyle' tariffs, where customers subscribe to a maximum quantity of energy consumption during peak hours.[96]

- Peak rebate tariffs where, instead of facing higher tariffs during a critical peak, distributors rewards customers for reducing their demand during times of network congestion. Customers may respond more positively to being rewarded for reducing usage during the peak and paying higher charges on average days than charged high prices during a peak and lower charges on average days. Powershop's 'Curb Your Power' program is a peak rebate tariff structure provided by a retailer.[97]

We consider that there can be strong benefits from innovative tariff designs if they result in greater efficiency, while managing customers' understanding and the impacts of reform. However, in a first-best situation retailers would develop the innovative tariffs based on more standard network tariff structures as a way to reduce the risks of prescribed tariffs, for example:

- Where distributors charge a demand tariff, retailers could develop demand subscription tariffs. In this approach, the distributor charges the retailer a demand tariff, and the retailer offers customers demand subscription packages, similar to mobile phone offers. The retailer could charge penalties for greater demand than the package.
- Where distributors charge a critical peak prices, retailers could develop peak rebates. In this approach, the distributor charges the retailer a critical peak price, and the retailer charges all customers a premium assuming normal demand during the critical peaks. Customers that reduce their usage during the critical peak would receive discounts, rewards or cash.

However, at present most retailers are passing through network tariff structures without innovating. We would consider innovative network tariff solution, just like any other tariff, as part of proposed TSS in the future.

Accumulation meters require anytime charges

Most residential customers still have accumulation meters. As the name suggests, accumulation meters add up/accumulate the amount of electricity used by a consumer during a set period. For households, this is quarterly. They cannot record disaggregated usage within that period, such as half hourly, which is the chief advantage of interval or smart meters. As such, distributors cannot charge these customers any form of cost reflective tariff that requires knowledge of when the customer is using the network.

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[96] Energex, *Annual Pricing Proposal – Distribution services for 1 July 2018 to 30 June 2019,* March 2018, pp. 55–56; Ergon Energy, *Annual Pricing Proposal – Distribution services for 1 July 2018 to 30 June 2019,* April 2018, pp. 56–57.

[97] Powershop, *Curb Your Power,* accessed 3 August 2018, https://www.powershop.com.au/demand-response-curb-your-power/

This requires an anytime charge, where the cost of using electricity does not change based on the time of the day, day of the week or month of the year. The tariff designs proposed by distributors for customers with accumulation meters are summarised in Table 18-21 below.

Table 18-21 Anytime charges for accumulation meters

Distributor	Residential customers	Business customers
Ausgrid	Flat tariffs (with inclining block tariffs for customers with usage less than 2MWh per year)	Flat tariffs (with inclining block tariffs for customers with usage less than 2MWh per year)
Endeavour Energy	Flat tariff	Inclining block tariff
Essential Energy	Flat tariff	Flat tariff
Evoenergy	Flat tariff (with inclining block tariffs for some customers)	Inclining block tariff
Power and Water	Flat tariff	Flat tariff
TasNetworks	Flat tariff	Flat tariff

We consider that flat tariffs are superior to inclining block tariffs. The costs of providing network services do not increase in line with the quantity of electricity consumed (in kWh) over a year. Inclining block tariffs offer no improvements in cost reflectivity, and are more difficult to understand. So we consider that distributors should charge customers on accumulation meters flat tariffs.

Large business should face highly cost reflective tariffs

Until this point, we have focused on tariff designs for residential and small business customers. The same NER pricing objective and principles apply to large businesses. However, we consider that we can expect large business customers to understand much more complex tariff designs. Large business customers will spend a large amount of money each year on electricity. This necessitates large customers investing in understanding their bills. This means that large business customers should face more cost reflective tariffs than small business and residential customers.

Most of the proposed large business tariffs use similar features to residential charges. However, we have not discussed two charges included in the tariff structure statement proposals so far:

- Capacity charges – a form of demand charge that looks at either a customer's maximum demand over a long period, such as 12-months, or on a customer's negotiated maximum capacity.
- Excess kVAr charges – a charge to customers for the inefficiency of their power factor to compensate the distributor for transporting reactive power.

The default tariff designs proposed by distributors for large customers are summarised in Table 18-22 below.

Table 18-22 Proposed large customer tariffs

	Low voltage	High voltage	Sub-transmission
Ausgrid	Annual capacity tariff with time of use energy	Annual capacity tariff with time of use energy	Annual capacity tariff with time of use energy
Endeavour Energy	Peak demand tariff with flat energy	Peak demand tariff with flat energy	Peak demand tariff with flat energy
Essential Energy	Time of use demand tariff with time of use energy	Time of use demand charge with time of use energy	Time of use demand charge with time of use energy
Evoenergy	Peak demand tariff with flat energy	Peak demand tariff with time of use energy and annual capacity charge	Not applicable
Power and Water	Peak demand tariff with flat energy and kVAr charges	Peak demand tariff with flat energy and kVAr charges	Not applicable
TasNetworks	Time of use demand tariff no energy charges	Capacity tariff with time of use energy	Not applicable

We are comfortable approving most of these tariff structures for large business customers. However, we consider it is important that tariff structures become more cost reflective over time.

We encourage distributors to propose more cost reflective tariff designs, such as location based critical peak pricing, on an optional basis for large customers. These customers should be able to understand these tariffs and may find such tariffs beneficial.

Additionally, most distributors provide individually calculated tariffs for some high voltage and sub-transmission customers. We consider that distributors should provide, in their Tariff Structure Statements, how they will calculate those individually calculated tariffs. This additional transparency provides:

- Existing and potential high voltage and sub-transmission customers greater certainty in their tariffs, and
- Protection for other customers from the potential for negotiated individually calculated tariff customers being systematically lower than the published large business charges.

Distributors should provide the AER how they have calculated individual tariffs as part of their annual pricing proposals, so that we can confirm they are consistent with the methodology in the tariff structure statements.

Is consistency important between distributors?

Under the National Energy Rules there is no explicit requirement for consistency between distributors. However, the National Energy Rules have a consistent set of pricing principles. To comply successfully with all the pricing principles there may need to be some commonality for a variety of reasons:

- Cost reflectivity - the cost drivers for most distribution businesses are generally the same, therefore to design a tariff that is cost reflective it is likely that the tariffs may need to be similar.
- Ability of customers to understand electricity charges - most customers only spend a small proportion of their time considering how their retailer calculates their electricity bill. Having consistent tariff designs, if that flows through to retail tariff design, may make it easier for Governments, distributors and retailers to help customers understand their bills.

In the three sections above, the National Energy Rules and the current state of tariff reform, have led us to propose a baseline set of tariff designs and assignment policies that distributors should aim to achieve (or explain any deviations).

We consider that if distributors apply our positions, outlined above, in their revised tariff structure statements, distributors will achieve a high level of consistency. This is not the aim of sections above, but a natural consequence of it. Overall, we consider that consistency between distributors is a positive to the extent that it makes tariffs cost reflective and makes it easier for customers to understand their electricity charges.

C Long run marginal cost

In this appendix, we set out our framework for assessing the method(s) a distributor used to derive its long run marginal cost (LRMC) estimates for its proposed tariff structure statement.

Background

When tariffs accurately reflect the marginal, or forward-looking, cost of increasing (or decreasing) demand, consumers can make informed choices about their electricity usage. Under such tariffs, customers would increase their use of the network only when they value it more than the costs. This in turn signals to distributors to invest in additional capacity to the extent that customers value it.[98]

LRMC is equivalent to such forward looking costs—more specifically, as measured over a period of time sufficient for all factors of production to be varied.[99] LRMC could also be described as a distributor's forward looking costs that are responsive to changes in electricity demand. This could include investment in additional network capacity to service growing peak demand.[100] As we discuss below, this could also include replacement of fixed assets at the end of their economic life where changes in demand is a consideration.

The estimation of LRMC involves three key steps, which are to:

- choose the overall approaches or estimation method(s)
- define what costs are considered 'marginal' vs. what costs are considered 'residual', and
- define what timeframe is considered the 'long run'.

As we discuss below, this provides the framework for our approach to assessing a distributor's LRMC estimation methods.

Note on LRMC, residual costs and approach to tariff setting

The Rules require network tariffs to be based on LRMC.[101] However, not all of a distributor's costs are forward looking and responsive to changes in electricity demand. For example, distributors may need to replace network assets when they are old and/or have deteriorating condition. Hence, if network tariffs only reflected LRMC, distributors would not recover all their costs. Costs not covered by a distributor's LRMC

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[98] Alternatively, customers may reduce their use of the network if the benefit they derive is less than the costs. This in turn signals to distributors the potential to reduce capacity in the network.

[99] NER, chapter 10 Glossary.

[100] Peak demand can be due to increased economic activity or seasonal factors such spikes in air-conditioner use on hot summer evenings.

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

are called 'residual costs'. The Rules 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.[102] This appendix sets out our assessment framework. It does not assess the approach the distributor proposed to use to set tariff levels in pricing proposals—including how it considered LRMC estimates to set such tariffs and how it allocates residual costs.[103] We consider this aspect in section 18.4.1.1and 18.4.2.1.

Assessment approach

This is the second TSS round for the electricity distribution businesses undergoing a distribution determination.[104] In this round, we are assessing the extent to which a distributor made improvements to its methods for estimating LRMC compared to the first TSS round. In particular, we assessed whether a distributor:

- investigated the inclusion of replacement capex (repex) in their LRMC calculations.[105]
- used a minimum of 10 years of forecast data in the calculation of LRMC.[106]
- continued to refine their methods for estimating LRMC so their tariffs better reflect efficient costs.[107]

These are the improvements we encouraged distributors to explore in our final decisions for the first TSS round, which we completed in 2016–17. The above criteria establish our approach for assessing LRMC estimation methods in this second TSS round.

Importantly, we consider these criteria allow us to assess the extent to which a distributor has progressed tariff reform as envisioned in the Rules, particularly the requirement that a distributor's method(s) of calculating LRMC has regard to:[108]

- the costs and benefits of implementing the method(s) of calculating LRMC
- the additional costs of meeting demand from customers at times of greatest utilisation of the relevant part of the distribution network
- the location of customers and the extent to which costs vary between different locations in the distribution network.[109]

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

103 NER, cl 6.18.1A(a)(5).

104 The exception is Power and Water, who was not required to submit a TSS in the first round. However, our final decisions from the first TSS round have been available to Power and Water to guide in developing its first TSS.

105 For example, see AER, *Final decision: Tariff structure statements: Ausgrid, Endeavour and Essential Energy*, February 2017, pp. 92–94.

106 For example, see AER, *Final decision: Tariff structure statements: Ausgrid, Endeavour and Essential Energy*, February 2017, p. 94.

107 For example, see AER, *Final decision: Tariff structure statements: Ausgrid, Endeavour and Essential Energy*, February 2017, p. 90.

108 NER, cl 6.18.5(f).

Broadly speaking, we would consider a distributor's LRMC estimation method contributes to the achievement of compliance with the pricing principles if the distributor:

- made the improvements discussed above to their LRMC estimation methods.
- explained its proposed approach within the context of the current stage of tariff reform and the Rules.

We discuss each of our criteria in more detail below.

Inclusion of repex in LRMC estimates

In our final decision for the first TSS round, we encouraged distributors to investigate including repex in their LRMC estimates.

<u>Assessment criteria:</u>

We consider whether repex (or any other types of capex) that a distributor includes in its LRMC estimates should meet the definition of 'marginal cost'—that is, the cost of an incremental change in demand.

Where a distributor has not included repex in their LRMC estimates, it must demonstrate why it does not have any forecast repex that can be considered as a 'marginal cost'.

In our final decision for the first TSS round, we noted the Rules define LRMC as the cost of an incremental change in demand over a period of time in which all factors of production can be varied.[110] In the long run, the level of capacity in a distribution network is a variable factor of production. 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. We considered LRMC estimates should include replacement capital expenditure and associated operating expenditure. This would promote network capacity in the long run to be at a level that consumers value.[111]

109 As we discuss in sections 0 and 0, we consider the location-based aspect of measuring LRMC is not a primary consideration at this stage of tariff reform, although it could become a more prominent consideration in future TSS rounds.

110 NER, chapter 10—Glossary.

111 For example, see AER, *Final decision: Tariff structure statements: Ausgrid, Endeavour and Essential Energy*, February 2017, pp. 92–93.

We also noted not all types of repex should be included in LRMC estimates.[112] Marginal cost refers to the cost of an incremental change in demand.[113] Not all repex is associated with an incremental change in demand. For example, we consider repex driven purely by asset condition would not be included in LRMC estimates.

If a distributor includes repex that is consistent with the definition of marginal cost, the next step is assessing whether it has incorporated such expenditure appropriately into its LRMC estimation method. We assess a distributor's incorporation of repex into its estimation method on a case by case basis. This is because we acknowledge LRMC estimates have not traditionally included repex in the context of Australian network regulation. We consider this second TSS round provides distributors (and other stakeholders, including the AER) with the opportunity to explore and test this aspect of LRMC estimation. Indeed, distributors have proposed several viable methods for incorporating repex into their LRMC estimates in this second TSS round.[114]

Definition of 'long run'

In our final decision for the first TSS round, we noted distributors have typically used timeframes of between 10 and 40 years to estimate long run marginal costs. We considered this timeframe captures the essence of 'long run'.[115]

Assessment criteria:

We consider distributors should use a minimum forecast horizon of ten years as inputs into their estimation methods to adequately capture the 'long run'. This is consistent with what we said in approving the first TSS round.

The Rules define long run marginal costs as the cost of an incremental change in demand over a period of time in which all factors of production can be varied.[116]

In the long run, the level of capacity in a distribution network is variable. Accordingly, the 'long run' would match the life of the assets. Some distribution network assets have very long lives (in excess of 60 years). However, it would be impractical to produce

112 For example, see AER, *Final decision: Tariff structure statements: Ausgrid, Endeavour and Essential Energy*, February 2017, pp. 92–93.

113 NER, chapter 10 (definition of long run marginal cost).

114 See attachment 18 of our respective draft decisions for those distributors with distribution determinations for the 2019–24 regulatory control period (Evoenergy, TasNetworks, Power and Water, Ausgrid, Endeavour Energy and Essential Energy).

115 For example, see AER, *Final decision: Tariff structure statements: Ausgrid, Endeavour and Essential Energy*, February 2017, p. 94.

116 NER, chapter 10.

accurate forecasts over such a long horizon. The longer the estimation period, the more difficult it becomes to estimate and forecast long run costs.[117]

We think there is no ideal, or correct, timescale on which to base these estimates and we accept a range of timeframes would be compliant with the Rules.

However, the timescale must be long enough to allow a significant number of factors of production to change—and a key factor of production is the level of capacity in the network. We consider a minimum forecast horizon of ten years captures the essence of 'long run'.

LRMC estimation methods

This section discusses our approach to assessing the extent to which distributors have made improvements to the LRMC estimations methods. This entails assessing whether the distributors:

- made improvements to their application of the Average Incremental Cost approach;[118] and/or
- explored the use of other estimation methods, such as the Turvey approach.

<u>Assessment criteria:</u>

In this second TSS round, we take a practical approach to assessing whether a distributor has made sufficient improvements to its LRMC estimation method(s).

We will be mindful of the costs and benefits to industry of using more accurate estimation methods in this early phase of tariff reform and will assess each proposal on a case by case basis.

As a base, we would consider a distributor has adequately improved its estimation method if it has properly incorporated repex (see section 0). We consider doing so demonstrates improved application of an LRMC estimation compared to the first TSS round.

In the first TSS round, all distributors in the National Electricity Market used the Average Incremental Cost approach to estimate LRMC, which we accepted. We encouraged distributors to continue improving their estimation methods so their tariffs better reflect efficient costs. This may entail modifying the Average Incremental Cost

117 For example, assumptions about future growth at zone substation and/or terminal stations become more difficult to forecast with a longer planning horizon.

118 All distributors used the Average Incremental Cost approach to estimate LRMC in the first TSS round.

approach, or utilising more sophisticated approaches, such as the Turvey approach if they consider it appropriate.[119]

A general perception is the Average Incremental Cost approach is less costly to implement than the Turvey approach, but produces less accurate estimates of LRMC.

Conversely, the Turvey approach is more costly to implement than the Average Incremental Cost approach, but is perceived or is in principle capable of producing estimates that better represent LRMC.[120]

A key question in our assessment (and for distributors in making their TSS) is whether the benefits of more accurate estimates of LRMC outweigh the costs of deriving them.[121] This cost-benefit equation will depend on the circumstance of each business.

We therefore assess the extent to which a distributor has made improvements to its estimation method on a case by case basis. The aspects of a distributor's circumstance that are relevant for our assessment include:[122]

- **Penetration of interval meters**—There is currently low penetration of interval or more advanced (smart) meters in most jurisdictions. This implies distributors can assign a relatively low proportion of customers to cost reflective tariffs (which should signal LRMC).[123] The principal benefit of cost reflective pricing is that customers' use of the network reflects the value they derive from such use. This would then provide the signal to distributors to efficiently invest in the network.[124]

  However, this link between cost reflective pricing, customer usage and network investment would require a 'critical mass' of customers that can receive LRMC signals and then respond to such signals.

- **Postage stamp pricing**— Distributors charge customers the same tariffs across their networks (except for a small number of bespoke tariffs offered to the distributor's largest customers). However, the marginal costs of distribution vary by location, based on the rate of change in demand and level of congestion within the substation or feeder zone (as well as temporal factors).[125] Accordingly, basing tariffs on an estimate of average LRMC or a part of the network's LRMC sends

119 For example, see AER, *Final decision: Tariff structure statements: Ausgrid, Endeavour and Essential Energy*, February 2017, p. 90.

120 For a discussion on the relative merits of these approaches, see NERA, *Economic Concepts for Pricing Electricity Network Services: A Report for the Australian Energy Market Commission*, 21 July 2014, pp. 14–16.

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

122 We discuss such issues further in section 0.

123 Such as demand charges or time of use charges.

124 A misconception is that cost reflective pricing will automatically lead to lower network investment and ultimately lower prices. Cost reflective pricing could lead to (efficient) higher investment and prices if customers value additional use of the network.

125 The NER recognises the potential differences in LRMC between different location the network—NER, cl 6.18.5(f)(3).

inefficient price signals to most, if not all, customers.[126]

Postage stamp pricing is less costly and simpler to administer for distributors and retailers than locational pricing.[127] It is also arguably more equitable for many end customers. It is therefore unclear the extent to which the industry would, or could, move away from postage stamp pricing in future tariff structure statements. We are not expecting any substantive move by distributors to move towards location-based pricing in this round of TSSs.

- **Transition to marginal cost pricing**—For many distributors, the levels of their cost reflective tariffs differ from their LRMC estimates. This is a legacy of previous practices, when the requirement to consider LRMC was much lower than the current version of the Rules.[128] Distributors are transitioning their tariffs toward their LRMC estimates having regard to customer impacts.[129]

Future directions

As with the first TSS round, we encourage distributors to continue to refine their methods for estimating LRMC in the third TSS round.

This may mean further refining the Average Incremental Cost method, or adopting more sophisticated estimation methods, such as the Turvey method, if distributors consider it can be justified on cost-benefit grounds. Distributors may also adopt multiple estimation methods, as we discuss below.

We further encourage distributors to continue exploring the types of repex—and other expenditure types—that can properly be considered as 'marginal cost' and hence included in LRMC estimates. As a corollary, we also encourage businesses to continue exploring how they incorporate repex and other expenditure types into their estimation methods. As we discussed above, distributors proposed alternative methods for incorporating repex into their LRMC estimates in this second TSS round. We consider the industry can use the learnings from this second TSS round to potentially consolidate the methods for including repex in LRMC estimates for subsequent TSS rounds.

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126 Endeavour Energy developed separate LRMC estimates for substation zones that have growing demand and substation zones with falling demand. Endeavour Energy proposed to base tariffs on the LRMC for substation zones that have growing demand.

127 There are several degrees to locational pricing. At a higher level, locational pricing could equate to pricing by "regions" of a network, where a region may encompass zone substations that are inter-related by customer or growth characteristics, for example. At a lower level, locational pricing could equate to pricing by zone substation or even by feeder.

128 Prior to the AEMC's rule change in 2014, the Rules stated distributors "must take into account" LRMC when setting prices (NER version 62, cl 6.18.5(b)(1)). The current Rules state tariffs "must be based" on LRMC (NER version 111, cl 6.18.5(f)).

129 NER, cl 6.18.5(h).

As required by the NER, we will be mindful of the costs and benefits of improving LRMC estimation methods in our assessment of future TSS.[130] In the sections above, we acknowledged several factors in the current stage of tariff reform that may limit the benefits of using more sophisticated estimation methods such as the Turvey method.

However, we are also mindful of the changes occurring in the energy industry that could remove, or at least lower, such barriers in future TSS rounds. Factors to consider for the third TSS round include ongoing progress regarding:

- **Penetration of interval or more advanced meters**—As discussed in the sections above, there is currently relatively low penetration of interval meters in most jurisdictions. This limits the extent to which distributors can send LRMC signals to customers.

  However, the AEMC's metering rule change took effect from 1 December 2017. This should promote increasing penetration of interval meters in the National Electricity Market.[131] Distributors should monitor the rate of interval meter penetration and consider the extent to which it can accelerate tariff reform in the third TSS round. This includes considering the benefits to distributors and its customers of deriving (and signalling) more accurate estimates of LRMC.

- **Postage stamp pricing**—as we discussed above, postage stamp pricing applies to a large majority of distributors' customers for administrative and equity reasons.

  The higher costs of more accurate methods to estimation LRMC may be justifiable where a distributor proposes tariffs that send locational signals of congestion. In future TSS rounds, a distributor may experiment with using such methods if it proposes to trial tariffs in particular areas of its network, for example.[132]

  Also, having regard to location when estimating LRMC does not require a distributor to actually apply location-based pricing. In this second TSS round, for example, Endeavour Energy produced two separate LRMC estimates: one for areas of stable or decreasing demand, and another for areas of increasing demand. However, Endeavour Energy still proposed to apply postage stamp pricing for the 2019–24 regulatory control period.[133]

  Having LRMC estimates by location also has benefits beyond pure tariff setting.

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

131 The AEMC metering Rules do not apply in the Northern Territory. We consider Power and Water's metering proposal in AER, *Draft Decision: Power and Water Corporation Distribution Determination 2019 to 2024: Attachment 15: Alternative control services*, September 2018.

132 We note distributors may also send temporal and/or location-based signals of network costs through non-tariff means, such as rebates or demand management initiatives.

133 Endeavour Energy based its prices on the latter estimates because Endeavour Energy considered the impact of inefficient signals in growing areas is greater than in areas of declining demand under postage stamp pricing. See Endeavour Energy, *TSS 0.04 Tariff Structure Explanatory Statement*, April 2018, p. 87.

> This is because it would help to identify locations where the benefits of demand management outweigh the costs. Location-based LRMC estimates would assist in the assessment of project costs with and without demand management in constrained areas of the network.
>
> We consider this is consistent with the Rules requirement that LRMC estimates have regard to the extent to which costs differ between locations (without actually applying locational pricing).[134] It also provided Endeavour Energy with further information regarding the appropriate LRMC estimate on which to base its prices.[135]

On this last point, we note distributors are not restricted to a single method when estimating LRMC. Just as distributors utilise a combination of different methods to derive their expenditure forecasts, they can use a combination of estimation methods to derive LRMC estimates.

Distributors may use different estimation methods to account for different types of marginal costs. Ausgrid did so in this second TSS round to measure the different contributions to LRMC of augmentation capex and replacement capex.[136] Distributors may use different estimation methods, where one method acts as the 'primary' estimation method, while a second method acts as a 'sanity check'. Or, distributors may use different estimation methods to derive a range for LRMC, rather than point estimates, as Ausgrid did in this second TSS round.[137]

On a final note, we propose consulting with distributors more regularly outside of the distribution determination process on progressing LRMC estimation methods. This is consistent with a suggestion from Energy Networks Australia in the first TSS round who stated the industry should devote resources to improve the estimation of LRMC.[138] We consider progressing estimation methods for LRMC is an area that could benefit from collaboration and knowledge-sharing between distributors and other stakeholders. This could spread the costs of developing more accurate estimation methods, while maximising the benefits of efficient price signals.

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[134] NER, cl 6.18.5(f)(3).

[135] NER, cl 6.18.5(f).

[136] Ausgrid, *Attachment 10.04 – Deloitte – LRMC Methodology Report*, December 2017, pp. 11–16.

[137] The Independent Pricing and Regulatory Tribunal of NSW did similarly for Sydney Water Corporation: IPART, *Final Report: Review of prices for Sydney Water Corporation From 1 July 2016 to 30 June 2020*, June 2016, pp. 288–289.

[138] ENA, *Submission: Australian Energy Regulator draft decision on tariff structure statement proposals*, 7 October 2016, p. 3.

D Assigning retail customers to tariff classes

This appendix sets out our draft determination on the principles governing assignment or reassignment of Evoenergy's retail customers for direct control services.[139] We approve Evoenergy procedures for assigning and reassigning retail customers to tariff classes.

Procedures for assigning and reassigning retail customers to tariff classes

The procedure outlined in this section applies to direct control services.

Assignment of existing retail customer to tariff classes at the commencement of the 2019–24 regulatory control period

1. Evoenergy' customers will be taken to be "assigned" to the tariff class which Evoenergy was charging that customer immediately prior to 1 July 2019 if:
   (a) they were a Evoenergy customer prior to 1 July 2019, and
   (b) they continue to be a customer of Evoenergy as at 1 July 2019.

Assignment of new retail customers to a tariff class during the 2019–24 regulatory control period

2. If, from 1 July 2019, Evoenergy becomes aware that a person will become a customer of Evoenergy, then Evoenergy will determine the tariff class to which the new customer will be assigned.
3. In determining the tariff class to which a customer or potential customer will be assigned, or reassigned, in accordance with paragraphs 2 or 5, Evoenergy will take into account one or more of the following factors:
   (a) the nature and extent of the customer's usage
   (b) the nature of the customer's connection to the network
   (c) whether remotely–read interval metering or other similar metering technology has been installed at the customer's premises as a result of a regulatory obligation or requirement.
4. In addition to the requirements under paragraph 3, Evoenergy, when assigning or reassigning a customer to a tariff class, will ensure the following:
   (a) that customers with similar connection and usage profiles are treated on an equal basis
   (b) those customers who have micro–generation facilities are treated no less favourably than customers with similar load profiles but without such facilities.

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[139] NER, cl. 6.12.1(17).

Reassignment of existing retail customers to another existing or a new tariff class during the 2019–24 regulatory control period

5. Evoenergy may reassign an existing customer to another tariff class in the following situations:
   (a) Evoenergy receives a request from the customer or customer's retailer to review the tariff to which the existing retail customer is assigned; or
   (b) Evoenergy believes that:
      i. an existing customer's load characteristics or connection characteristics (or both) have changed such that it is no longer appropriate for that customer to be assigned to the tariff class to which the customer is currently assigned, or
      ii. a customer no longer has the same or materially similar load or connection characteristics as other customers on the customer's existing tariff, then Evoenergy may reassign that customer to another tariff class.

Notification of proposed assignments and reassignments and rights of objection for standard control services

6. Evoenergy must notify the customer's retailer in writing of the tariff class to which the customer has been assigned or reassigned, prior to the assignment or reassignment occurring.
7. A notice under paragraph 6 above must include advice informing the customer's retailer that they may request further information from Evoenergy and that the customer or customer's retailer may object to the proposed reassignment. This notice must specifically include:
   (a) a written document describing Evoenergy's internal procedures for reviewing objections, if the customer's retailer provides express consent, a soft copy of such information may be provided via email
   (b) that if the objection is not resolved to the satisfaction of the customer or customer's retailer under Evoenergy internal review system within a reasonable timeframe, then, to the extent resolution of such disputes are with the jurisdiction of an Ombudsman or like officer, the customer or customer's retailer is entitled to escalate the matter to such a body
   (c) that if the objection is not resolved to the satisfaction of the customer or customer's retailer under Evoenergy's internal review system and the body noted in paragraph 7(b) above, then the customer or customer's retailer is entitled to seek a decision of the AER via the dispute resolution process available under Part 10 of the NEL.
8. If, in response to a notice issued in accordance with paragraph 6 above, Evoenergy receives a request for further information from a customer or customer's retailer, then it must provide such information within a reasonable timeframe. If Evoenergy reasonably claims confidentiality over any of the information requested by the customer or customer's retailer, then it is not required to provide that information to the customer or customer's retailer. If the customer or customer's retailer disagrees

with such confidentiality claims, he or she may have resort to the complaints and dispute resolution procedure, referred to in paragraph 7 above (as modified for a confidentiality dispute).

9. If, in response to a notice issued in accordance with paragraph 6 above, a customer or customer's retailer makes an objection to Evoenergy about the proposed assignment or reassignment, Evoenergy must reconsider the proposed assignment or reassignment. In doing so Evoenergy must take into consideration the factors in paragraphs 3 and 4 above, and notify the customer or customer's retailer in writing of its decision and the reasons for that decision.

10. If an objection to a tariff class assignment or reassignment is upheld by the relevant body noted in paragraph 7 above, then any adjustment which needs to be made to tariffs will be done by Evoenergy as part of the next network bill.

11. If a customer or customer's retailer objects to Evoenergy's tariff class assignment Evoenergy must provide the information set out in paragraph 7 above and adopt and comply with the arrangements set out in paragraphs 8, 9 and 10 above in respect of requests for further information by the customer or customer's retailer and resolution of the objection.

Notification of proposed assignments and reassignments and rights of objection for alternative control services

12. Evoenergy must make available information on tariff classes and dispute resolution procedures referred to in paragraph 7 above to retailers operating in Evoenergy's distribution area.

13. If Evoenergy receives a request for further information from a customer or customer's retailer in relation to a tariff class assignment or reassignment, then it must provide such information within a reasonable timeframe. If Evoenergy reasonably claims confidentiality over any of the information requested, then it is not required to provide that information. If the customer or customer's retailer disagrees with such confidentiality claims, he or she may have resort to the dispute resolution procedures referred to in paragraph 7 above, (as modified for a confidentiality dispute).

14. If a customer or customer's retailer makes an objection to Evoenergy about the proposed assignment or reassignment, Evoenergy must reconsider the proposed assignment or reassignment. In doing so Evoenergy must take into consideration the factors in paragraphs 3 and 4 above, and notify the customer or customer's retailer in writing of its decision and the reasons for that decision.

15. If an objection to a tariff class assignment or reassignment is upheld by the relevant body noted in paragraph 7 above, then any adjustment which needs to be made to tariffs will be done by Evoenergy as part of the next network bill

System of assessment and review of the basis on which a retail customer is charged

16. Where the charging parameters for a particular tariff result in a basis charge that varies according to the customer's usage or load profile, Evoenergy will set out in

its pricing proposal a method of how it will review and assess the basis on which a customer is charged.