DRAFT DECISION

TasNetworks 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 TasNetworks' 2019–24 distribution determination. It should be read with all other parts of the draft decision.

The draft decision includes the following attachments:

Overview

Attachment 1 – Annual revenue requirement

Attachment 2 – Regulatory asset base

Attachment 3 – Rate of return

Attachment 4 – Regulatory depreciation

Attachment 5 – Capital expenditure

Attachment 6 – Operating expenditure

Attachment 7 – Corporate income tax

Attachment 8 – Efficiency benefit sharing scheme

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Shortened forms

Shortened form	Extended form
ACS	alternative control services
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
augex	augmentation expenditure
capex	capital expenditure
CCP	Consumer Challenge Panel
CESS	capital expenditure sharing scheme
CPI	consumer price index
DRP	debt risk premium
DMIAM	demand management innovation allowance (mechanism)
DMIS	demand management incentive scheme
distributor	distribution network service provider
DUoS	distribution use of system
EBSS	efficiency benefit sharing scheme
ERP	equity risk premium
Expenditure Assessment Guideline	Expenditure Forecast Assessment Guideline for Electricity Distribution
F&A	framework and approach
MRP	market risk premium
NEL	national electricity law
NEM	national electricity market
NEO	national electricity objective
NER	national electricity rules
NSP	network service provider
opex	operating expenditure
PPI	partial performance indicators
PTRM	post-tax revenue model
RAB	regulatory asset base
RBA	Reserve Bank of Australia

Shortened form	Extended form
repex	replacement expenditure
RFM	roll forward model
RIN	regulatory information notice
RPP	revenue and pricing principles
SAIDI	system average interruption duration index
SAIFI	system average interruption frequency index
SCS	standard control services
SLCAPM	Sharpe-Lintner capital asset pricing model
STPIS	service target performance incentive scheme
WACC	weighted average cost of capital

Glossary of terms

Term	Interpretation
Apparent power	See kVA
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).
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.
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.
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.
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.

Term	Interpretation
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.
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".*
NER	National Electricity Rules
Power factor	The power factor is the ratio of real power to apparent power (kW divided by kVA).
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 structure	Tariff structure is the shape, form or design of a tariff, including its different components (charges) and how they may interact.
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.
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 (ToU 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 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 TasNetworks' tariff structure statement to apply 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, the distributor's policies and procedures for assigning customers to tariffs, the charging parameters for each tariff, and a description of the approach the distributor to setting tariffs in pricing proposals. It is accompanied by an indicative pricing schedule.[1] A tariff structure statement provides consumers and retailers with certainty and transparency in relation to how and when network prices will change.

This allows consumers to make more informed decisions about their energy use and result in better outcomes for both individual consumers and the overall electricity system. In particular, the tariff structure statement informs customer choices by:

- providing better price signals—tariffs which reflect what it costs to use electricity at different times allow customers to make informed decisions to better manage their bills
- transitioning tariffs to greater cost reflectivity—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 by setting out the distributor's tariff approaches for a set period of time.

Background to this decision

This is TasNetworks' second tariff structure statement and applies to the 2019–24 regulatory control period. It must comply with the NER distribution pricing principles.[2] These principles require distributors to transition to cost reflective tariffs and, in doing so, to account for impacts on consumers.

In the future direction section of our final decision on TasNetworks' first tariff structure statement, which applied for the 2017–19 regulatory control period, we noted that transitioning to cost reflective pricing will take more than one regulatory control period

1 NER, cl. 6.18.1A(a).

2 NER, cl. 6.18.5.

to achieve.[3] We set an expectation that to comply with the NER, each tariff structure statement proposal should propose additional reforms.[4]

In our final decision on TasNetworks tariff structure statement applying to the 2017–19 regulatory control period, we also stated that there were some elements of TasNetworks' tariff structure statement proposal which comply with the distribution pricing principles but which, in our view, would benefit from further consideration in future. [5]

Specifically, to provide guidance to TasNetworks for its 2019–24 tariff structure statement, we previously identified that TasNetworks should:[6]

- move from an opt-in approach to an opt-out approach to network tariff reform
- update the timeframe for the unwinding of discount inherent in some of TasNetworks tariffs
- revise charging windows to more closely reflect the times of network congestion
- refine its method for estimating long run marginal cost (LRMC), including the inclusion of replacement capex within marginal cost estimates.

18.1 TasNetworks' proposal

TasNetworks' tariff structure statement proposed for the 2019–24 regulatory control period seeks to continue the pricing reform commenced as part of the 2017–19 TSS by:

- applying an 'introductory' discount to its demand based time of use tariffs for both residential and small business customers to encourage take up
- introducing new tariffs specifically for embedded networks
- continuing its approach to progressively reduce longstanding cross-subsidies between customers and between tariffs
- collecting smart mater and trial data to help better manage customer impacts in future phases of network tariff reform.

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3 AER, *TasNetworks distribution final determination 2017– 19, Attachment 19 Tariff structure statement* April 2017 p. 12.

4 AER, *TasNetworks distribution final determination 2017– 19, Attachment 19 Tariff structure statement* April 2017 p. 12.

5 AER, *TasNetworks distribution final determination 2017– 19, Attachment 19 Tariff structure statement* April 2017 p. 12.

6 AER, *TasNetworks distribution final determination 2017– 19, Attachment 19 Tariff structure statement* April 2017.

18.2 Draft decision

Our draft decision is to accept the following elements of the TasNetworks' tariff structure statement, as we consider that these contribute to compliance with the distribution pricing principles and to the achievement of the network pricing objective.[7]

- unwinding of the current discounts associated with some tariffs
- including distributed energy resources tariffs in their current form.

However, our draft decision is also to not accept the following elements of TasNetworks' 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:

- the opt-in approach for tariff assignment. We consider that an opt-out approach is more appropriate.
- the description of how the estimate of long run marginal costs have been reflected in the indicative pricing schedule
- its reliance on the annual pricing process to document the criteria for assigning customers to particular tariffs and tariff classes
- the justification for including embedded network tariffs, both in terms of its objective and calculation.

We commend TasNetworks for the significant consultation it has undertaken to help develop its tariff structure statements. In particular, the establishment and engagement of its Pricing Reform Working Group has allowed TasNetworks to develop stakeholder understanding of its tariff framework and provide informed feedback. An example of this initiative's effectiveness followed the release of our issues paper.[8] TasNetworks was able to effectively and efficiently gather stakeholder views on a change to its tariff assignment policy which we identified as a key element of the proposal under review.[9]

18.3 Assessment approach

This section outlines our approach to tariff structure statement assessments.

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.[10]

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7 NER cl. 6.18.5 (a)

8 AER, *Issues Paper TasNetworks Distribution and Transmission Determination 2019-24,* March 2018

9 TasNetworks, Pricing Reform Workgroup Meeting, 20 July 2018.

10 NER, cl. 6.18.1A(a).

Second, a tariff structure statement must also comply with the distribution pricing principles.[11]

What must a tariff structure statement contain?

The NER requires a tariff structure statement to include:[12]

- 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.[13] 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.[14] 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[15]
- 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[16]
- 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[17]

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11 NER, cl. 6.18.1A(b).
12 NER, cl. 6.18.1A(a).
13 NER, cl. 6.8.2(d1).
14 NER, cl. 6.18.1A(b).
15 NER, cl. 6.18.5(e).
16 NER, cl. 6.18.5(f).
17 NER, cl. 6.18.5(g).

- distributors must consider the impact on customers of tariff changes and may depart from efficient tariffs, if reasonably necessary having regard to:[18]
    - 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[19]
- tariffs must otherwise comply with the NER and all applicable regulatory requirements.[20]

The tariff structure statement must comply with the distribution pricing principles in a manner that will contribute to the achievement of the *network pricing objective:*[21]

> *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.*[22]

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.

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.

18 NER, cl.6.18.5(h).

19 NER, cl. 6.18.5(i).

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

21 NER, cl. 6.18.5(d)

22 NER, cl. 6.18.5(a)

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 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.[23]

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.[24] 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.[25]

18.4 Reasons for draft decision

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23 NER, cl. 6.18.1A(c).

24 NER, cl. 6.18.1B.

25 NER, cl. 6.18.1B(d).

Our draft decision is to not accept certain aspects of TasNetworks' 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 TasNetworks' 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.

18.4.1 Residential and small business tariffs

We are satisfied that the following aspects of TasNetworks 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:

- the inclusion of demand charges as part of the default cost reflective tariff
- the progressive reduction of longstanding discounted tariffs between customers and between tariffs
- the determination of charging windows that reflect times of network congestion
- the introduction of two demand tariffs for residential and small business customers designed to encourage the uptake of distributed energy resources (DER).[26]

Despite this, we are not satisfied that TasNetworks tariff assignment policy for residential and small business customers which relies on retailers 'opting-in' to discounted cost reflective network tariffs will provide an adequate pace of reform.

We require TasNetworks to adopt an 'opt out' arrangement, whereby retailers face a cost reflective network tariff by default when a customer meets the trigger for tariff assignment or reassignment.

18.4.1.1 Tariff design, levels and charging windows

Default cost reflective tariff

TasNetworks' proposal is to base its default cost-reflective tariff on demand charges. Consistent with our view in the 2017–19 regulatory control period, we consider demand charges are cost reflective to the extent TasNetworks' forward looking costs are driven

[26] DER being customers who investment in technologies like solar generation, batteries and electric vehicles.

by network expenditure to manage congestion at times of peak demand.[27] In addition to demand charges, we also consider time of use based energy charges can also signal times when the network is likely to experience congestion and enable customers to shift their usage outside of peak times. These charges can complement demand time based charges.

TasNetworks' default cost-reflective tariff is a demand based time of use tariff that comprises a service charge and demand based time of use charges with both peak and off-peak charging windows. There are no energy or consumption based charges.[28] Table 18-2 below shows the charging parameters and indicative price levels across the 2019–24 regulatory control period for TasNetworks residential demand based time of use tariff.

Table 18-2 TasNetworks demand based time of use tariff (TAS87)

	2019-20	2020-21	2021-22	2022-23	2023-24
DUoS Daily Charge (cents/day)	56.902	58.609	60.368	62.179	64.044
DUoS Peak Demand Charge (cents/kW/day)	22.202	22.893	23.695	24.564	25.523
DUoS Off-peak Demand Charge (cents/kW/day)	3.696	4.574	5.523	6.544	7.649
TUoS Peak Demand Charge (cents/kW/day)	7.884	7.605	7.374	7.134	6.885
TUoS Off-peak Demand Charge(cents/kW/day)	1.313	1.519	1.719	1.901	2.063

Source: TasNetworks, Tariff Structure Statement Appendix B: Indicative Prices for 2019-24.

As a principle, we consider network tariffs with demand charges which are higher during times of network congestion and lower during times when the network is not congested enhance cost reflectivity. As Table 18-2 shows TasNetworks is projecting significant change over the 2019–24 regulatory control period between its peak and off-peak demand charges that work in reverse to this principle.[29] That is, in 2019 the peak NUOS demand charge is approximately 6 times the off-peak demand charge which is projected to fall to approximately 3 times by 2024.[30]

We are also mindful that the NER also requires that distributors make progress towards long run marginal cost (LRMC) based pricing and the efficient recovery of

[27] AER, *TasNetworks distribution final determination 2017–2019, Attachment 19 Tariff structure statement April 2017* p. 10.

[28] TasNetworks, *Tariff Structure Statement 2019-24, January 2018*, p.135.

[29] Peak and off-peak periods apply at different times which correspond to times of network congestion. A customer's maximum demand during the peak charging window attracts a different charge compared to their maximum demand during the off-peak period.

[30] Network Use Of System referred to as NUOS is made up of two principal components – Standard Distribution Use of System (DUOS) and the Transmission Use of System (TUOS). The DUOS component covers the operations and maintenance cost and investment return on distribution network assets. The TUOS component covers the operations and maintenance cost and investment return on transmission network assets.

residual costs. In doing so, we note the concerns of Aurora Energy which submitted that the benefits of demand tariffs have not been demonstrated and there is a risk their introduction may impose higher costs to Tasmanian consumers for no commensurate benefit.[31]

TasNetworks included an appendix to its tariff structure statement that discusses network tariff design and the approach taken by it to determine the demand charges by reference to long run marginal cost.[32] Nevertheless we requested additional detail from TasNetworks regarding its approach.[33] We reviewed this material and consider that TasNetworks revised tariff structure statement should describe more comprehensively how its long run marginal cost estimates translate into its indicative price schedule.

Consistent with our final decision on the 2017–19 regulatory control period, we are satisfied that the peak demand charging windows of 7am to 10am and 4pm to 9pm are likely to align with periods of network stress, and that they remain wide enough to discourage customers shifting load and creating new peaks at other times. We also consider that TasNetworks should consider seasonal based charging windows, particularly where there is a distinct seasonal aspect to peak demand, we discuss charging windows and seasonality further in the next section.

We provide more detailed technical guidance in appendices B and C on what we would expect of TasNetworks, and distributors in general, in demonstrating compliance the distribution pricing principles, including our views on tariff design and estimation of LRMC.

Refinement of charging windows appropriate

A time of use tariff has defined charging windows in which different usage charges apply. Often charging windows are also known as the 'peak' window, 'shoulder' window, and 'off-peak' window. We consider that peak demand charging windows should reasonably reflect times of likely network stress but should also be wide enough to avoid load shifting that creates new peaks at other times.

TasNetworks has proposed changes to the number of charging windows and the times of day these apply for the 2019–24 regulatory control period. For simplicity, TasNetworks proposed to move from three charging periods (peak, shoulder and off-peak) to two periods (peak and off-peak) for its new demand network tariffs.

For its residential and small business demand tariffs, TasNetworks has proposed a peak charging window of 10am to 4pm and 7pm to 9pm weekdays. Off-peak rates would apply at other times on weekdays and all day on weekends.[34]

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31 Aurora Energy, *Submission on TasNetworks distribution and transmission determination*, 18 May 2018, p. 5.

32 TasNetworks, *Tariff Structure Statement 2019-24*, *Appendix C: Designing cost reflective tariffs,* January 2018.

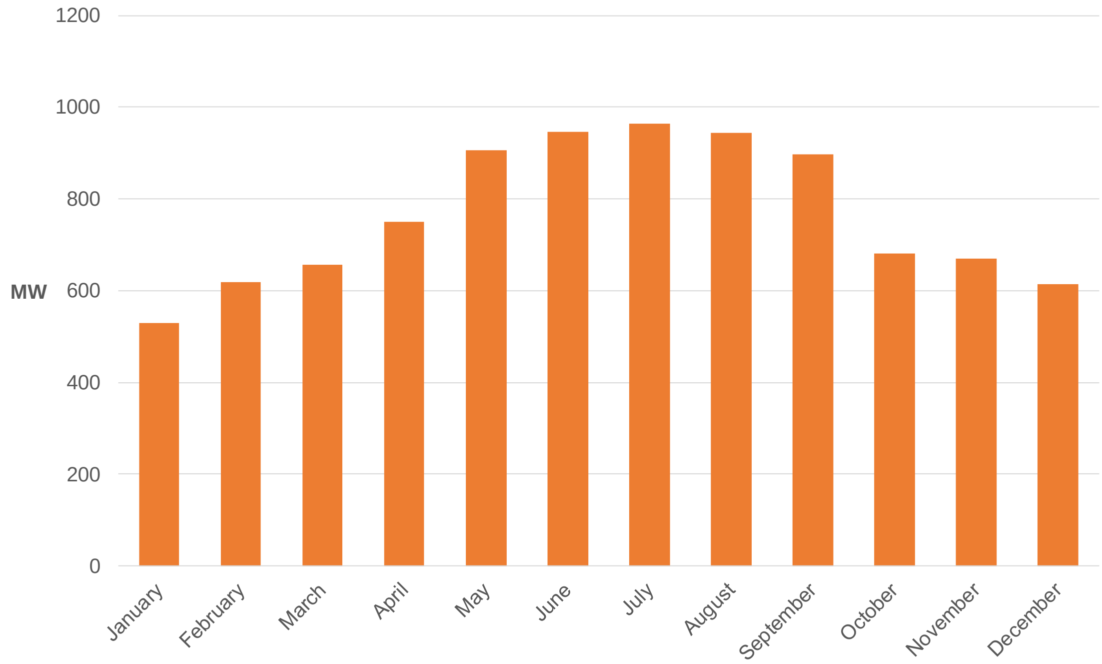
33 AER, *Information Request to TasNetworks #002 and #022.*

34 TasNetworks, *Tariff Structure Statement 2019-24, January 2018*, p.148.

We are satisfied that TasNetworks proposal to remove the shoulder period and adopt an approach which only has peak and off-peak is appropriate. We agree this increases simplicity without comprising on cost reflectivity.

Figure 18-1 shows that TasNetworks has a distinct winter seasonal peak demand. This being the case, we consider that customers would be better off in the long run with a lower "off peak" seasonal tariff. That is, if demand charges are calculated on the basis of a winter peak, charges should be lower in the off peak months, thereby lowering customers' bills. By contrast, a uniform price year round means that winter peaking customers are benefiting at the expense of summer peaking customers.

Figure 18-1 TasNetworks 2017 coincident raw system maximum demand



Source: AER analysis of data provided by TasNetworks in response to AER information request #022

TasNetworks' tariff structure statement includes discussion of the use of seasonality as part of demand pricing.[35] However, TasNetworks stated it chose not to introduce seasonality in its charging windows for simplicity and based on customer feedback. We requested additional information about this aspect of its proposal.[36] As discussed in appendix B, we consider that seasonal tariffs are more cost-reflective.

In response to customer feedback about seasonality, TasNetworks proposes no seasonal differences due to complexity for consumers to understand and respond to effectively. TasNetworks considers introducing seasonality would impact on customers during winter periods. TasNetworks cites research from a Tasmanian customer trial

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[35] TasNetworks, *Tariff Structure Statement 2019-24, January 2018*, p. 147.

[36] AER, *Information request to TasNetworks #022*, 8 June 2018, p. 20.

that found that customers were forgoing heating to avoid higher retail bills during winter months.[37]

We are satisfied, at this stage of tariff reform, that the benefits of seasonality be pursued in the future tariff structure statements. In determining this we consider unwinding the discounted tariffs, discussed above, would need to occur before introducing seasonality. We note that these discounted tariffs are for heating and heating consumption is highest in winter. In these circumstances, a default tariff that includes a winter peak charge would be likely to be unappealing to customers.

Unwinding discounted tariffs

TasNetworks tariff structure statement proposes to realign the relative prices of several existing tariffs to eliminate some longstanding discounts available to different customer groups.[38] Specifically, the discounts apply to the following tariffs:

- Business LV Nursing Homes (tariff TAS34)
- General Network Business Curtilage (tariff TASCURT)
- Uncontrolled LV Heating tariff (tariff TAS41).

The discounts are apparent when comparing the tariff levels for these network tariffs with the predominant legacy tariff in each tariff class. TasNetworks proposes to realign the first two of these tariffs to the predominant legacy LV business tariff by 2021.[39] With the uncontrolled LV Heating tariff to achieve parity with the predominant residential legacy tariff by 2029.

We are satisfied TasNetworks' proposed continuation of removing discounts between legacy tariffs is an appropriate part of the transition towards cost reflectivity. The removal of these discounts will ensure that TasNetworks can assign customers to a more cost reflective tariff with comparable customer impacts as the predominant legacy tariff is transitioned to cost reflectivity.

While we accept TasNetworks proposal to remove these discounts, we consider TasNetworks can and should improve the transparency of its proposal. TasNetworks can achieve this by reflecting the latest available information (for example, accounting for changes in annual revenue requirements) and also by demonstrating that it has considered the available options for unwinding these discounts under the NER.

This is particularly the case for the uncontrolled low voltage heating tariff. TasNetworks strategy for this tariff involves a 15 year transition with the aim of minimising significant customer price impacts. It based this trajectory on an anticipated significant drop in network revenues in recent years which did not materialise and therefore meant that TasNetworks would be unable to minimise the network charge impact on customers.

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37 TasNetworks, *Response to AER information request #022,* 15 June 2018, p. 20.

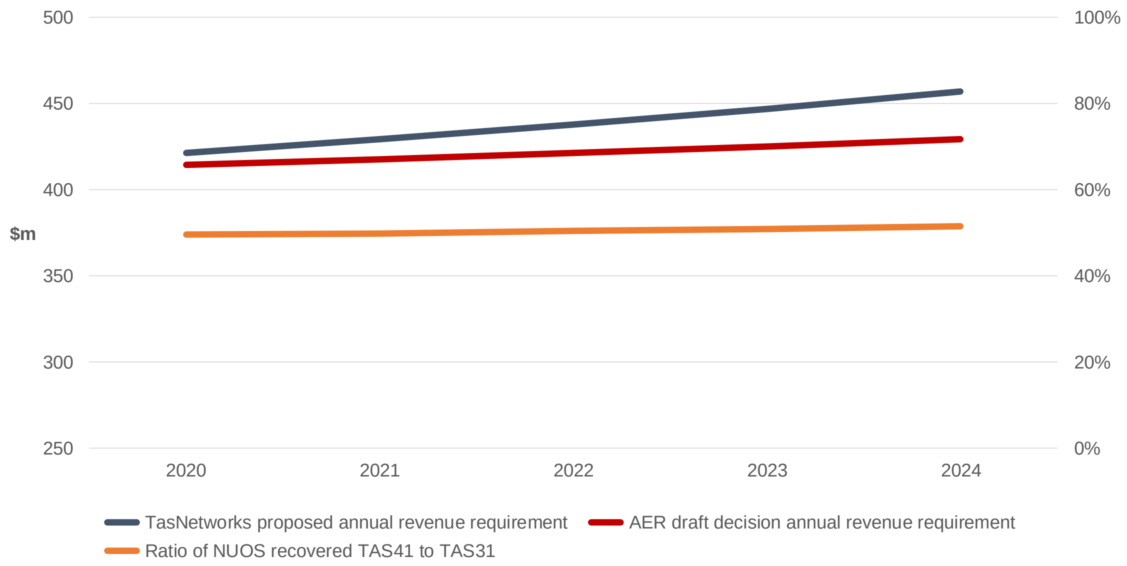
38 TasNetworks, *Tariff Structure Statement 2019-24,* January 2018, p. 9.

39 TasNetworks, *Tariff Structure Statement 2019-24,* January 2018, p. 21.

The Tasmanian Small Business Council has raised concerns at the apparent stalling in the removal of these discounts.[40]

TasNetworks considers alignment by 2028-29 is still achievable. However, this would require a forecast price increase of approximately 15 per cent in the first year of the 2024-29 regulatory control period for the uncontrolled heating tariff.[41] To give context to TasNetworks proposed trajectory for unwinding the discounts applying to the uncontrolled LV heating tariff, we considered trends in overall revenue and the contribution of these relevant tariffs. This is shown below in Figure 18-2.

Figure 18-2 Trend in TAS41, TAS31 and overall NUOS revenue (real $2018 million)



Source: AER analysis of data provided by TasNetworks in response to AER information request #022

Our draft decision increases total NUOS revenue by approximately 4 per cent from the first year of the 2019–24 regulatory control period to the last. We consider that, all else being equal, the NUOS recovered under the discounted heating tariff should increase relative to the legacy tariff over the regulatory control period. Figure 18-2 shows this ratio remaining largely constant across the period. We acknowledge that there are many factors influencing revenue levels across time. As such, we requested TasNetworks provide further detail on the current proposed trajectory for realignment and clarify its position on progressing these realignments.[42]

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40 Tasmanian Small Business Council, *TasNetworks transmission revenue and distribution regulatory proposal,* 16 May 2018, p. 13.

41 TasNetworks, *Response to AER information request #022,* 15 June 2018, p. 20.

42 AER, *Information request to TasNetworks #022*, 8 June 2018.

In its response, TasNetworks reiterated that it is not proposing any sudden abolition of the discounted tariffs.[43] We agree that TasNetworks should, where possible, avoid abrupt rebalancing and maintain awareness of customer impacts when determining the pace of realigning these tariffs. This includes customer impacts identified by both TasCOSS and the Tasmanian Renewable Energy Association submissions that unwinding the discounts requires consideration of how the impacts on customers are managed.[44]

After having regard to these factors, we consider TasNetworks is proposing modest realignment of these discounts within the 2019–24 regulatory control period. We acknowledge the side-constraint provisions in the NER limit price movements for tariffs within regulatory control periods.[45] Despite this, we consider there are alternatives to price shocks in the 2019 (the first year of the regulatory control period) that TasNetworks should demonstrate it has considered.

In particular, we consider TasNetworks should investigate whether it can provide certainty about its approach to removing these discounts. Under our draft decision which projects a lower annual NUOS revenue requirement, TasNetworks tariff structure statement could prioritise price relief to the non-discounted tariffs. Further, while the side-constraint provisions do apply throughout the 2019–24 regulatory control period we consider TasNetworks should consider realignment of the discounted tariffs to the extent permissible.[46]

To better understand the context of the tariff levels of these discounted tariffs we have investigated the market characteristics in Tasmania and have documented our findings in appendix A. As discussed in that appendix, we consider forecast network charges are well below historic levels, which provides the opportunity to accelerate this unwinding.

Technology neutral distributed energy resources tariffs

TasNetworks tariff structure statement proposes to include two time of use demand tariffs that will be available on an opt-in basis to encourage customer uptake of distributed energy resources such as solar PV, batteries or energy management devices.

We have previously rejected other “technology-targeted” tariffs (e.g. SA Power Networks' solar tariff). This was in part, because we consider efficiency is better promoted through technology neutral approaches and a well-designed cost reflective

43 TasNetworks, *Response to AER information request #022,* 15 June 2018, p. 20.

44 Tasmanian Council of Social Service, *Submission to AER issues paper TasNetworks distribution and transmission determination*, May 2018, p. 6 and Tasmanian Renewable Energy Alliance, *Submission to AER issues paper TasNetworks distribution and transmission determination*, May 2018. p. 3.

45 NER, cl. 6.18.6.

46 That is, under NER, cl. 6.18.6(c) individual tariffs can increase at the greater of CPI–X plus 2 per cent or CPI plus 2 per cent.

tariff can apply to customers with and without DER. We acknowledge that TasNetworks proposal appears to raise similar concerns as the SA Power Networks solar tariff, we are satisfied however that there are differences between the situations, discussed below.

The tariff will be a two-part tariff comprising a fixed charge and peak and off-peak demand charges. The tariff does not include a usage charge for total consumption.[47] We are satisfied that TasNetworks proposal is appropriate because:

- following extensive consultation, and subsequent reconsideration, TasNetworks now proposes to apply the same prices and discount to its residential demand tariff that is available to all customers with appropriate metering. That is, while it will have two residential demand tariffs (one available only to customers with DER; and one available to all customers) – these two demand tariffs will have the same price including discount
    - TasNetworks had originally planned to apply the discount only to the residential DER tariff. If TasNetworks had proceeded with that plan, we may have had some concerns with that approach as it would not have been technology neutral
    - however, TasNetworks consulted on this approach with its Pricing Reform Working group.[48] TasNetworks now intends to apply the discount to both sets of tariffs. Given the demand tariffs to customers with and without DER will now have the same price, we consider this largely addresses potential concerns around (not) being technology neutral.
- SA Power Networks proposed to charge customers with solar PV a higher tariff than otherwise equivalent customers without solar PV. In this case, by applying the discount only to the residential tariff, TasNetworks would have been treating customers with DER "more favourably" than customers without DER. As noted above, however, TasNetworks now intends to apply the discount to both sets of tariffs.

For these reasons we approve these demand tariffs in their current form.

18.4.1.2 Tariff assignment policy

Opt-out approach to tariff assignment required for adequate tariff reform progress

In the 2017–19 round of tariff structure statement we supported an initial customer-led transition to cost reflective network tariffs followed by assignment principles that support a faster pace of reform.[49] For TasNetworks, this initial customer-led transition

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[47] TasNetworks, *Tariff Structure Statement 2019-24,* January 2018, p. 12.

[48] TasNetworks Pricing Reform Workgroup Meeting #3, April 2017

[49] AER, *TasNetworks distribution final determination 2017-2019, Attachment 19 - Tariff Structure Statement*, April 2017 pp. 19–10.

meant introducing the time of use demand tariffs to customers on an opt-in basis with legacy tariffs remaining open.

At the time we made the 2017–19 determination, we set an expectation that TasNetworks next tariff structure statement should consider whether default assignment to cost reflective tariffs with opt-out provisions or mandatory assignment may be more appropriate.[50] Our draft decision is to require TasNetworks to amend its approach to tariff reform from an opt-in to an opt-out based approach.

In determining this we considered the market characteristics and projected pace of tariff reform in Tasmania and how this compares to approaches in other jurisdictions. We also had regard to the views of stakeholders and the impact of opt-out on customers recognising the circumstances in Tasmania. We discuss each of these aspects below.

Market characteristics and projected pace of tariff reform

TasNetworks notes that despite full retail contestability for residential and lower end small business electricity markets commencing in 2014, the Tasmanian Government-owned incumbent, Aurora Energy remains the predominant retailer.[51] Table 18-3 shows, Aurora Energy sells electricity to almost all small customers in the state.

Table 18-3 Tasmania retail statistics for small customers

	2013	2014	2015	2016	2017	2018
Aurora Energy	264 422	266 113	270 429	272 490	273 565	275 618
Other retailers	0	4	63	119	167	170
Total customers	264 422	266 117	270 492	272 609	273 732	275 788

Source: AER retail market statistics.

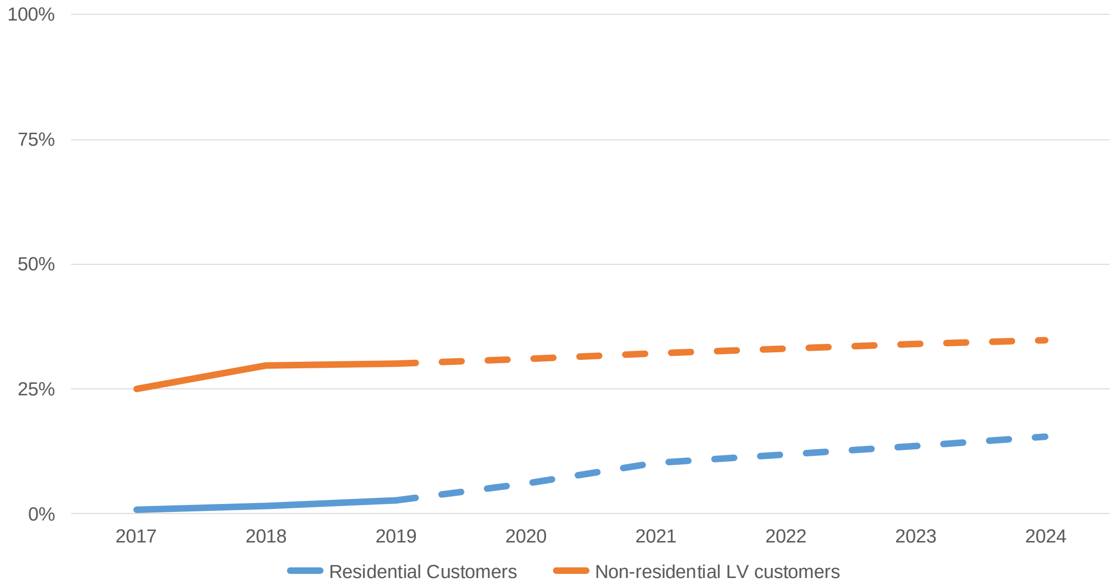
This being the case, the rate at which Aurora Energy's customers are assigned to TasNetworks' cost reflective network tariffs is a key determinant of the progress to cost reflectivity.

To determine the historic and forecast effectiveness of an opt-in approach to tariff reform we requested TasNetworks provide data on the penetration of cost-reflective tariffs historically and its projections for the 2019–24 regulatory control period. Figure 18-3 below illustrates this trend.

50 AER, *TasNetworks distribution final determination 2017-2019, Attachment 19 - Tariff Structure Statement*, April 2017, pp.19–31.

51 TasNetworks, *Tariff Structure Statement 2019-24,* January 2018, p. 33.

Figure 18-3 Proportion of customers on cost reflective tariffs



Source: AER analysis of data provided by TasNetworks in response to AER information request #022.

This trend demonstrates that the experiences so far under an opt-in approach, and the projections for the 2019–24 regulatory control period, do not represent an adequate pace of tariff reform for transitioning small customers to cost reflective network tariffs.

To understand what might be driving this and whether an opt-out approach to tariff assignment policy might be more effective, we have investigated the market characteristics of Tasmania and have documented these findings in appendix A. On the basis of this analysis we consider the move to opt-out is appropriate given:

- the residential and LV business segments in TasNetworks network area have a high annual share of total energy consumption and total customers. This highlights how important these customers are to realising the benefits of tariff reform
- TasNetworks operate under a revenue cap, which when considered with the highly concentrated retail market share means Aurora Energy faces predictable network charges, This should mean that Aurora Energy is well placed to innovate its retail products to drive tariff reform
- the projected increase of interval metering from 1 per cent customer penetration in 2016 to approximately 61 per cent in 2024 reiterates the significance of the 2019-24 regulatory period for achieving the objectives of tariff reform
- TasNetworks, when compared with other distributors, has experienced a lower uptake of cost-reflective network tariffs. For example, Evoenergy, which has adopted an opt-out approach, has 28 per cent of customers on cost reflective tariffs.

Stakeholder views on move to opt-out approach to tariff reform

In our issues paper we sought stakeholder views about whether TasNetworks' tariff assignment policy placed a strong enough incentive on retailers to reform their retail offerings.[52]

In particular, we sought views on whether TasNetworks should move to an opt-out approach. We received several submissions on this matter:

- CCP13 recommend the AER set clear expectations in the draft decision and to favour a shorter timeframe for tariff reform.[53] CCP 13 noted that an accelerated reform program should be pursued given price regulation and limited competition[54]
- Aurora Energy submitted that despite full retail contestability commencing in Tasmania in 2014 it is required to offer regulated standard retail (standing offer) contracts. This means that the maximum prices that Aurora Energy can charge its customers is set by the Tasmanian Economic Regulator. In addition to this, Aurora Energy notes that the Tasmanian Government legislated to cap price increases at the consumer price index for the next three years. This prohibits Aurora Energy's ability to pass through cost reflective movements in network prices to customers.

We recognise that customer affordability is a key policy consideration for the Tasmanian Government, and that the legislated CPI price constraint seeks to address this. We also consider that this constraint limits the flexibility of supply-side market participants, including retailers, to vary network tariff structures to achieve cost reflectivity.

We consider that an orderly transition to cost-reflectivity is required under the Network Pricing Objective in the NER for TasNetworks' network tariffs to reflect efficient network costs.[55] The absence of efficient network pricing impacts customers' ability to appreciate the impact their demand has on both the capital and operating expenditure of TasNetworks. Noting the typical long life of network assets, this can have implications for the long term interests of consumers that can conflict with achieving the National Electricity Objective in the NEL.[56]

Our draft decision is to require TasNetworks to amend its tariff structure statement to adopt an opt-out approach to tariff assignment. We note that maximum retail prices, as determined by the Tasmanian Economic Regulator, have a flat, usage based structure, and increases in retail electricity prices must be no more than the change in the CPI. Aurora Energy will take on some risk if network prices are based on demand while

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52 AER, *Issues paper, TasNetworks Transmission and Distribution determination 2019-24, March 2018*, p. 39.

53 Consumer Challenge Panel, CCP Sub-Panel No. 13, *Advice to the AER, Response to proposals from TasNetworks for a revenue reset for the 2019–24 regulatory period,* 16 May 2018, p. 8.

54 Consumer Challenge Panel, CCP Sub-Panel No. 13, *Advice to the AER, Response to proposals from TasNetworks for a revenue reset for the 2019–24 regulatory period,* 16 May 2018, pp. 7–8.

55 NER, cl. 6.18.5 (a).

56 NEL, s. (7).

retail tariffs remain based on usage. However, Aurora Energy will take on these risks progressively as new meters are installed in customers' premises. The immediate effect is not likely to be great. Aurora Energy has some ability to manage these risks, for example by encouraging customers to shift loads away from peak periods or by encouraging them to invest in energy efficiency.

In doing so, we are satisfied that a default time of use demand or consumption tariff design is appropriate considering the circumstances of TasNetworks and its customers given the market characteristics. As we discuss in appendix B, we consider that both these tariffs represent a level of cost reflectivity appropriate for this phase of tariff reform.

Amendment of trigger for tariff assignment required

TasNetworks describes its process for assigning customers to particular tariff classes and tariffs in its tariff structure statement.[57] In doing so, TasNetworks has regard to a set of criteria it uses to ensure it treats customers with similar connection and usage profiles equally.[58] TasNetworks tariff structure statement indicates it may reassign customers to another tariff class if there are material changes in the customer's load characteristics.[59]

As we discuss above regarding tariff assignment policy, TasNetworks has undertaken further consultation on adopting an opt-out approach. In its response to our information request regarding tariff assignment policy options TasNetworks stated its preferred option for triggering opt-out tariff assignment arrangements for residential customers is for this to be applied to:

- new connecting customers;
- customers changing their connection characteristics or arrangements, for example, existing customers upgrading their connection to three-phase or an existing customer who installs solar PV; and
- Customers who receive an advanced meter but do not otherwise alter their connection arrangements (i.e. replacement).[60]

We consider that 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 TasNetworks proposed trigger for reassignment will stimulate tariff reform, we require TasNetworks to modify the trigger slightly, so that the opt-out assignment is implemented immediately, where:

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

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57 TasNetworks, *Tariff Structure Statement 2019-24,* January 2018, pp. 44–47.

58 TasNetworks, *Tariff Structure Statement 2019-24,* January 2018, p. 44.

59 TasNetworks, *Tariff Structure Statement 2019-24,* January 2018, p. 45.

60 TasNetworks, *Response to AER information request #022,* 15 June 2018, p. 7.

(b) a customer initiates a change to their connection configuration that is identifiable to the distributor[61]

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

We consider that TasNetworks can combine the first two triggers of its proposal to 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.

18.4.2 Medium and large business tariffs

With the exception of TasNetworks proposal to include embedded network tariffs, we are satisfied that TasNetworks 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 TasNetworks' tariff structure statement appropriately assigns medium and large business customers to cost-reflective network tariffs while taking into account their connection and usage profiles.

Below we set out our reasons for this decision and discuss areas of TasNetworks revised tariff structure statement we consider require further clarity. In particular, we require that TasNetworks' tariff structure statement be amended to provide further justification for its embedded networks tariff and to include more detail on its assignment process.

18.4.2.1 Tariff design, levels and charging windows

TasNetworks has three tariff options for large customers connected at high voltage, as Figure 18-4 illustrates.

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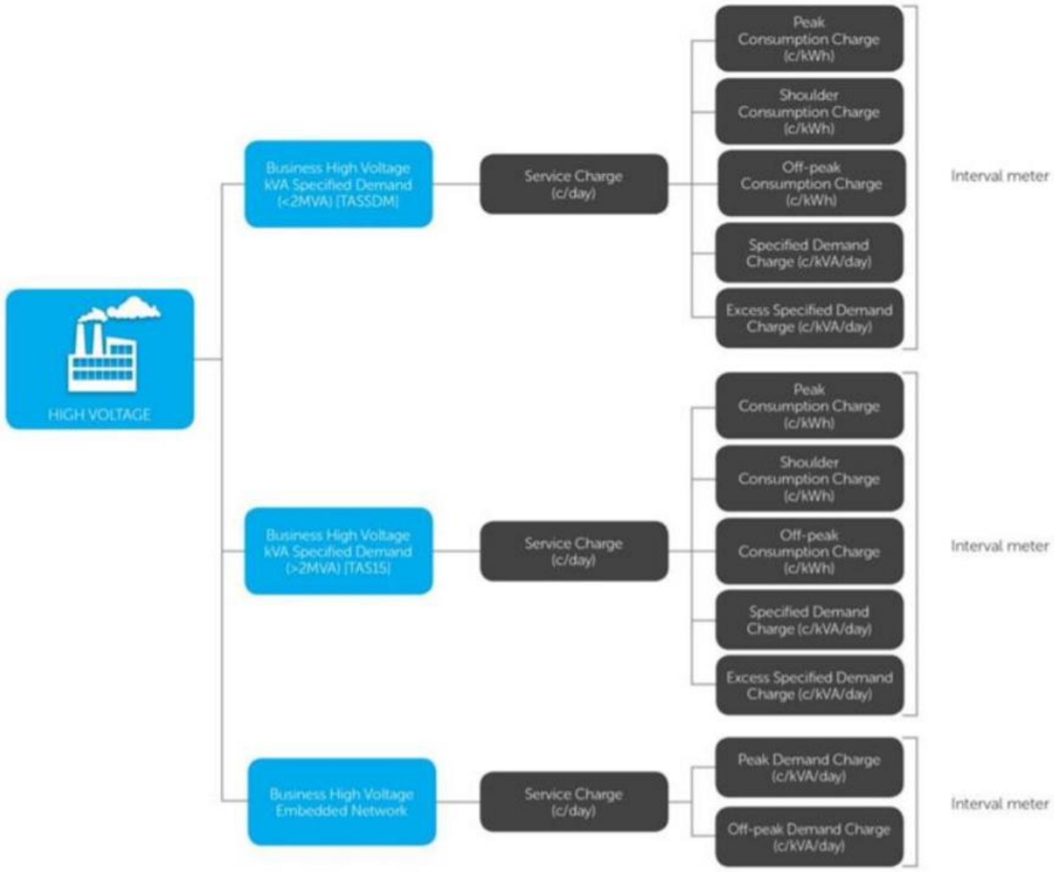
[61] Changes to connection configuration include the installation of embedded generation and upgrades to three-phase power.

Figure 18-4 TasNetworks tariff design for large customers connected at HV



Source: TasNetworks tariff structure statement p. 27.

With the exception of the embedded network tariffs, we are satisfied the structure of these tariffs are appropriate for this stage of tariff reform. These tariffs include time based consumption charges which when applied in conjunction with demand charges exhibit cost reflectivity. Appendix B below discusses in further detail our consideration of tariff structures and their cost-reflectivity.

Embedded network tariffs

TasNetworks tariff structure statement introduces two network tariffs specific to embedded networks. One for embedded networks connecting at LV, the other for embedded networks connecting at HV. TasNetworks proposes these tariff structures to comprise a service charge, and with both peak and off-peak demand based charges.[62]

[62] Peak and off-peak periods apply at different times which correspond to times of network congestion. A customer's maximum demand during the peak charging window attracts a different charge compared to their maximum demand during the off-peak period.

TasNetworks has stated the objective of the embedded network tariff is to be both more “cost reflective” and for embedded networks to make an “equitable contribution towards the cost of the distribution network”.[63] CCP 13 recommended we thoroughly test this proposal given its view that there had been an absence of consultation on this tariff.[64]

We requested more detail on from TasNetworks on its proposed embedded network tariffs.[65] Specifically, we requested that TasNetworks:

- clarify how its proposed embedded network tariffs are more cost-reflective than existing network pricing arrangements and lead to a more equitable contribution towards the cost of the distribution network
- provide detail on how it quantified the price levels for these embedded network tariffs as well as information on existing embedded networks currently operating on the network
- explain the relative costs for embedded networks to provide network services with regard to density of consumption and diversified use when compared to the average customer for which embedded network customers are currently referenced to.

In response to this request, TasNetworks noted that it derived its proposed embedded network tariffs based on a number of assumptions, and that on reflection it would prefer to take further time to consider the best pricing approach for embedded network customers.[66] TasNetworks stated it required further data to allow it to undertake revised modelling, analysis and customer engagement and reconsider its approach for the 2024–29 regulatory control period.[67]

We require TasNetworks to amend its tariff structure statement to remove these embedded network tariffs. In doing so we consider that TasNetworks (and other distributors) should continue to investigate whether a specific embedded network tariff is appropriate under the NER.

When developing a specific embedded network tariff, we encourage distributors to consider the existing incentives for embedded networks to emerge as high voltage aggregators of LV residential/small business customers.

If distributors form the view that differences in network pricing across tariff classes are incentivising embedded networks, we would expect any proposal for an embedded network tariff to be accompanied by detailed modelling.

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63 TasNetworks, *Tariff Structure Statement 2019-24,* January 2018, p. 17.

64 Consumer Challenge Panel, CCP Sub-Panel No. 13, *Advice to the AER, Response to proposals from TasNetworks for a revenue reset for the 2019–24 regulatory period,* 16 May 2018, p. 70.

65 AER, *Information request to TasNetworks #022*, 8 June 2018.

66 TasNetworks, *Response to AER information request #022,* 15 June 2018.

67 TasNetworks, *Response to AER information request #022,* 15 June 2018, p. 19.

We consider that any proposal from a distributor must not only establish that the incentive exists but also must substantiate how its existence is not in the long term interests of consumers. Any proposal must show consideration for alternative measures to introducing an embedded network tariff that may serve the long term interests of consumers - for example, whether the AER network exemption guideline can be amended to produce the same consumer benefit.[68]

Individually calculated tariffs

TasNetworks tariff structure statement includes individually calculated tariffs as part of its suite of network tariffs. These tariffs apply to customers with a demand in excess of 2 MVA or where a customer's connection point necessitate an individual calculation of a contribution to the shared network charges.[69]

Historically, the electricity distributors have operated in a unidirectional way. This means that all customers use the sub-transmission network segment of the distribution networks, with subsets of customers using the high-voltage network and low voltage networks. This being the case, we are satisfied that it is appropriate network tariffs distinguish these customers based on their usage. Given the complexity of their connection arrangements, we are satisfied that in certain circumstances, it is more cost reflective for these customers to be assigned an individually calculated tariff, rather than the highly averaged published tariff.

TasNetworks tariff structure statement describes the basis of these tariffs, noting that it takes the actual transmission use of system charges to which it adds connection and distribution use of system charges.[70] We accept that there are limitations on the transparency distributors can provide regarding the circumstances of particular customers as these can be commercially sensitive.

We do however expect TasNetworks to provide further description on how it determines these as part of its revised tariff structure statement. We consider this will improve transparency and better inform customers with respect to their own circumstances. This further description may take the form of elaborating on the principles already contained within the tariff structure statement, and may also extend to example calculations.

18.4.2.2 Tariff assignment policy

Consistent with our decision for residential and small customers, we require TasNetworks to include in its tariff structure statement the criteria it uses to ensure it treats customers with similar connection and usage profiles equally. This includes the circumstances in which it reassigns customers to another tariff class if there are material changes in the load characteristics. Currently, TasNetworks' tariff structure

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68 AER, *Network service provider registration exemption guideline*, March 2018.

69 TasNetworks, *Tariff Structure Statement 2019-24,* January 2018, p. 39.

70 TasNetworks, *Tariff Structure Statement 2019-24,* January 2018, p. 39.

statement references the documents it submits as part of its Annual Pricing approval process. We require this detail to be incorporated into the tariff structure statement as this provides greater certainty around TasNetworks tariff assignment procedures.

18.4.3 Long run marginal cost estimate

An important feature of this draft decision is the concept of LRMC. LRMC is equivalent to the forward looking cost of a distributor providing one more unit of service, measured over a period of time sufficient for all factors of production to be varied.[71] 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.[72] 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.[73]

This section sets out our considerations of TasNetworks' approach to calculating long run marginal costs (LRMC). We used the framework detailed in appendix C as the basis of our assessment regarding compliance with the pricing principles.

Below we describe TasNetworks' 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).

18.4.3.1 TasNetworks estimation method

TasNetworks used the Average Incremental Cost approach to estimate the LRMC over a 10 year forecast period. TasNetworks forecasts increasing network demand over the 10 year forecast period.

Compared to the 2017–19 tariff structure statement, TasNetworks made some refinements to the LRMC such as:

- including some types of asset replacement expenditure associated with changes in demand; and
- providing a description of the calculation process and accounting for diversity factors between tariffs. Further data collection is underway with the emPOWERing

71 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.

72 NER, cl. 6.18.5(f).

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

You trial for improving on how to account for diversity in customers' contribution to network peak demand and thus the allocation of LRMC.

As in the 2017–19 tariff structure statement, TasNetworks continued to estimate the LRMC for each network tariff as indicated in Table 18-4. TasNetworks stated it has set the demand components of its network charges at or near the estimates in Table 18-4.[74]

Table 18-4 LRMC estimates for each tariff

Tariff Class	Network Tariff	LRMC ($/kW) 2019-20
High Voltage	Business High Voltage kVA Specified Demand (TASSDM)	101
	Business High Voltage Embedded Network	101
	Business High Voltage kVA Specified Demand > 2 MVA	118
Irrigation	Irrigation Low Voltage Time of Use (TAS75)	121
Large Low Voltage	Business Low Voltage kVA Demand (TAS82)	89
	Business Low Voltage Embedded Network	89
	Large Low Voltage Commercial Time of Use Demand (TAS89)	89
Small Low Voltage	Low Voltage Commercial Time of Use Demand (TAS88)	117
	Business Low Voltage Distributed Energy Resources	117
	Business Low Voltage General (TAS22)	147
	Business Low Voltage Nursing Homes (TAS34)	90
	General Network – Business, Curtilage (TASCURT)	147
	Business Low Voltage Time of Use (TAS94)	117
Residential	Residential Time of Use Demand Tariff (TAS87)	152
	Residential Low Voltage Distributed Energy Resources	152

74 We discuss the proposed levels of TasNetworks' tariffs in sections 18.4.1.1 and 18.4.2.1, and in appendix A.

	Residential Low Voltage General (TAS31)	152
	Residential Low voltage PAYG (TAS101)	152
	Residential Low Voltage Time of Use (TAS93)	152
Uncontrolled Energy	Uncontrolled Low Voltage Heating (TAS41)	105
Controlled Energy	Controlled Low Voltage Energy – Off-peak with afternoon boost (TAS61)	110
	Controlled Low Voltage Energy – night period only (TAS63)	110
Unmetered	Unmetered Supply Low Voltage General (TASUMS)	149
Street Lighting	Unmetered Supply Low Voltage Public Lighting (TASUMSSL)	149

18.4.3.2 Assessment of LRMC approach

We are not satisfied that TasNetworks' approach to estimating long run marginal cost (LRMC) contributes to compliance with the distribution pricing principles or to the achievement of the network pricing objective. In particular, we consider that TasNetworks' LRMC estimates include repex projects or programs in its LRMC estimates which increase the capacity of the network,[75] rather than being responsive to changes in demand.

Incorporation of repex into LRMC

We do not consider TasNetworks' proposed approach to incorporating repex into its LRMC estimates contributes to compliance with the distribution pricing principles or to the achievement of the network pricing objective.

TasNetworks submitted it included repex projects or programs which are forecast to increase the capacity of the network:[76]

- because it is the only option, e.g. due to technical progress or changed regulatory requirements
- although this capacity cannot be immediately realised due to other network constraints.

[75] TasNetworks, *Response to information request #34 – Long run marginal cost, 30 July 2018*, p. 5.

[76] TasNetworks, *Response to information request #34 – Long run marginal cost*, 30 July 2018, p. 5.

For each such project, the proportion of the overall project costs that relates to increasing network capacity was determined, and these costs were included in the LRMC calculations.

We consider that these projects involve the replacement of assets based on both condition and age. While some of these projects may involve a change in network capacity, incremental use of the network is not a driver of this replacement capex. As we set out in appendix C, incremental changes in demand must be the driver for any expenditure to be consistent with the definition of 'marginal cost'. This being the case, we are not satisfied that TasNetworks approach is consistent with the definition of LRMC. We require TasNetworks to amend its estimates as part of its revised proposal. Appendix C to this draft decision sets out guiding principles for estimating LRMC. We require TasNetworks to apply these principles in its revised proposal.

Estimation method

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

As we discuss in appendix C, LRMC largely depends on the level of congestion in different locations within a network (as well as temporal factors). However, postage stamp pricing applies across TasNetworks' 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.

In this context, we consider that 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.[77] In particular, the Average Incremental Cost approach uses inputs that are readily available as part of their regulatory proposal: namely, the expenditure and demand forecasts for the 2019–24 regulatory control period.

Forecast horizon

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

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

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

18.4.4 Statement structure and completeness

TasNetworks must include the following elements within its tariff structure statement:

- the tariff classes into which its customers will be grouped
- the policies and procedures TasNetworks will apply for assigning customers to tariffs or reassigning customers from one tariff to another (including applicable restrictions)
- the structures for each proposed tariff
- the charging parameters for each proposed tariff
- a description of the approach that TasNetworks will take in setting each tariff in each annual pricing proposal during the regulatory control period.[78]

TasNetworks must also accompany its proposed tariff structure statement with an indicative pricing schedule which sets out, for each tariff for each regulatory year of the regulatory control period, the indicative price levels determined in accordance with the tariff structure statement.[79]

TasNetworks tariff statement proposal largely incorporates each of the elements required under the rules.

We do however consider that TasNetworks proposal was not sufficiently clear regarding the policies and procedures for assigning customers to tariffs. TasNetworks does discuss the process it proposes for assigning customers to particular tariff classes and tariffs in its tariff structure statement.[80]

TasNetworks references a set of criteria it uses to ensure it treats customers with similar connection and usage profiles treated equally and reassigning customers to another tariff class if there are material changes in the customer's load characteristics.[81]

In its tariff structure statement, TasNetworks references the Network Tariff Application and Price Guide it submits as part of its Annual Pricing approval process as providing more detail on these assignment process.[82]

We reviewed both TasNetworks proposed tariff structure statement and the latest annual pricing proposal documents and consider that for completeness, the criteria should be included within the tariff structure statement. That is, we require TasNetworks to include the detailed criteria and procedures it relies on to assign or reassign customers between network tariffs in its tariff structure statement. When we

78 NER, cl.6.18.1A(a).

79 NER, cl.6.18.1A(e).

80 TasNetworks, *Tariff Structure Statement 2019-24,* January 2018, pp. 44–47.

81 TasNetworks, *Tariff Structure Statement 2019-24,* January 2018, p. 44.

82 TasNetworks, *Tariff Structure Statement 2019-24,* January 2018, pp. 46–47.

raised this issue with TasNetworks, they noted the AER's preference for including tariff assignment criteria in the tariff structure statement and have undertaken to revise their tariff structure statement accordingly.[83]

Tariff structure statement form

If, in making our final determination, we do not approve TasNetworks' proposed tariff structure statement, we must include in our determination an amended tariff structure statement which is:

- determined on the basis of TasNetworks' proposed tariff structure statement, and
- amended from that basis only to the extent necessary to enable it to be approved in accordance with the NER.[84]

TasNetworks' tariff structure statement currently relies on a single tariff structure statement document which combines the NER requirements with broader explanatory material regarding its overall tariff strategy and reasoning.[85] While not strictly a requirement, we request that TasNetworks adopt a "two document" approach to structuring the tariff structure statement as part of its revised proposal. The first document should only include the elements of the tariff structure statement listed in the NER as the constituent elements. A further separate document should contain TasNetworks' reasons for each of these proposed elements (i.e. an explanatory document).

The separation of the tariff structure statement document from the reasons provides a number of benefits:

- it makes it much easier to identify if the tariff structure statement is complete and includes each of the required elements[86]
- if we do not approve an element of a revised tariff structure statement proposal, it makes it much easier to identify that element
- it provides a shorter, clearer and more concise document for application during the regulatory control period. It also makes it easier for stakeholders to understand the tariff structures which apply over the regulatory control period. Further, this also makes the AER's task of assessing compliance of annual pricing proposals against the tariff structure statement easier.

These two documents would be in addition to the tariff structure statement overview document and indicative pricing schedule. We note that this is an approach that other distributors adopted in their 2017–19 tariff structure statements. We consider that both

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83 TasNetworks, *Response to AER information request #022*, 15 June 2018, p. 9.

84 NER, cl 6.12.3(l).

85 TasNetworks, *Tariff Structure Statement 2019-24,* January 2018

86 As listed in NER clause 6.18.1A.

Endeavour Energy and SA Power Networks proposals from those years provide good examples to follow.[87]

[87] Endeavour Energy, *Tariff Structure Statement*, October 2016 and Endeavour Energy, *Tariff Structure Statement*, *Explanatory Statement,* October 2016. SA Power Networks, *Revised Tariff Structure Statement 2017-2020 Part A*, October 2016 and SA Power Networks, *Revised Tariff Structure Statement 2017-2020 Part B*, October 2016.

A Retail/network characteristics and relevance to tariff reform in Tasmania

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 NER.[88]

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

Key Characteristics of the Tasmanian Electricity Network

TasNetworks owns, operates and maintains the transmission and distribution electricity networks on mainland Tasmania and Bruny Island. Electricity is generated by hydro,

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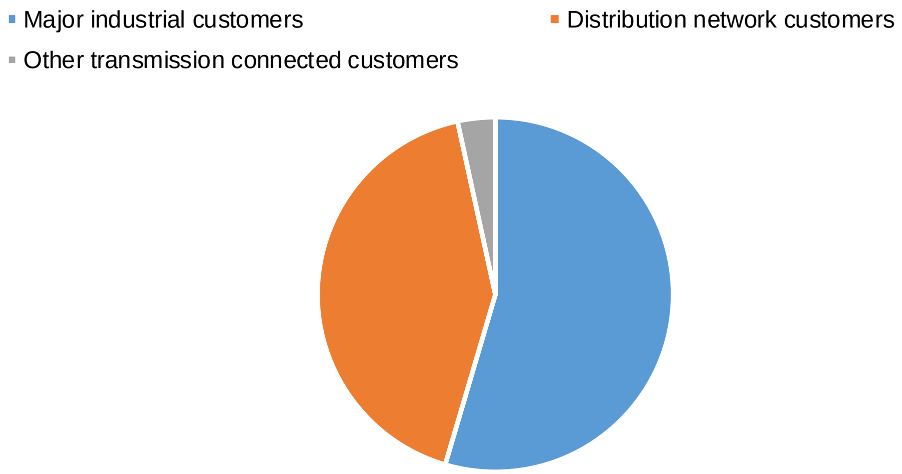
88 NER, cl. 6.18.1A.

wind and gas-fired power stations is delivered to approximately 260 000 electricity distribution customers throughout the state. TasNetworks' electricity transmission network currently comprises 1,701 km of circuit lines at 220 kV, and some parallel 110 kV lines, that transport power from several major generation centres to major load centres and Basslink.

Around half of the energy transported through the electricity network in Tasmania is supplied to a small number of very large industrial and commercial customers that are directly connected to TasNetworks electricity transmission network, with the remaining customers connected to TasNetworks electricity distribution network. This is illustrated in Figure 18-5 below.

Figure 18-5 Energy supplied from TasNetworks transmission network



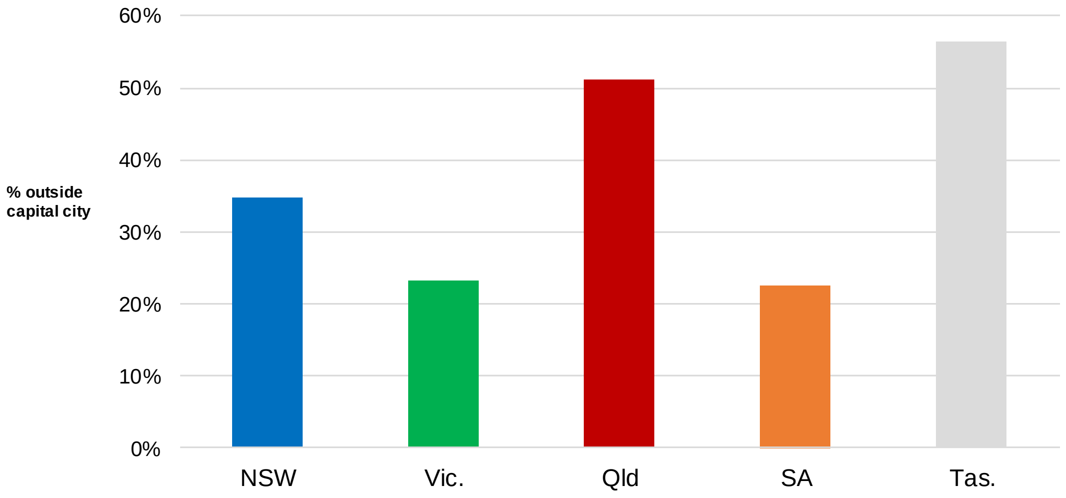
Source: TasNetworks, *Annual Planning Report 2018,* p. 27.

The Tasmanian electricity network comprises:

- a sub-transmission voltage network in greater Hobart, including Kingston and one sub-transmission line on the west coast of Tasmania, which provides supply to the high voltage network in addition to transmission-distribution connection points,
- a high voltage network of distribution lines that distribute electricity from transmission-distribution connection points and zone substations to the lower voltage network and a small number of customers connected directly to the high voltage network; and
- distribution substations and low voltage circuits providing supply to the majority of customers in Tasmania.

Comparing Tasmania to other distributors, we note that while customer density in Tasmania is similar to South Australia, the demographics are considerably different between these two jurisdictions. The majority of South Australia's population live in Adelaide, whereas Tasmania and Queensland have a highly dispersed population with around 57 per cent and 51 per cent, respectively, of their populations living outside of a capital city, as highlighted in the figure below. This population diversity has influenced the design of their rural electricity networks, often resulting in a greater quantity of network assets being required to reach more remote load centres.

Figure 18-6 Percentage of population living outside capital city by State



Source: ABS, *3218.0: Regional Population Growth, Australia*, 24 April 2018.

Victoria and South Australia have the least dispersed populations in Australia with approximately a quarter of their total populations living outside of a capital city. The higher population density has influenced the design of their urban electricity networks and contributed to higher utilisation rates of network assets compared to other networks.

Maximum Demand Growth

Another characteristic of TasNetworks network is the rate of growth in maximum demand. We note the key insights from the Australian Energy Market Operator (AEMO) regional forecasts of annual maximum demand covering the period 2017 to 2027;[89]

- Queensland is the only NEM region that is forecast to experience growth in maximum demand in both winter and summer over the decade to 2027
- maximum demand in summer is forecast to decline over the decade in South Australia and Victoria
- Tasmania and NSW are forecast to experience an initial decline in maximum demand with an upturn expected in the latter part of the forecast period.

Notably, Tasmania is the only NEM region that is winter peaking.

[89] https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/NEM_ESOO/2017/2017-Electricity-Statement-of-Opportunities.pdf

Table 18-5 shows the current AEMO medium term forecast of annual maximum demand by NEM region under neutral scenario at 50% POE level.

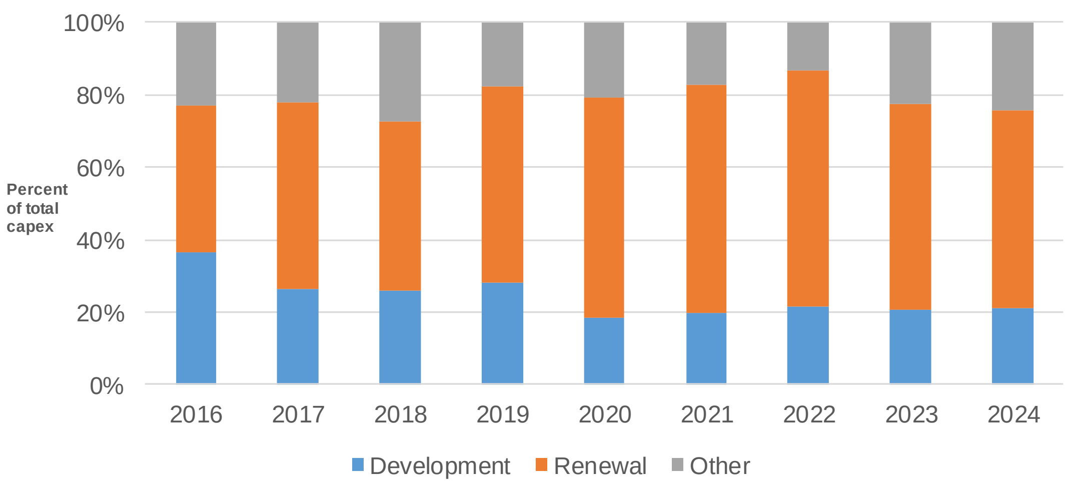
Table 18-5 Forecast Annual Maximum Demand (50% POE) by NEM region

	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.*

Weak growth in peak demand has reduced the need for distributors to invest in network augmentation, resulting in replacement becoming a more dominant driver of capital expenditure. This trend is highlighted in the figure below that shows that replacement-related capital expenditure (referred to as renewal in the figure) is forecast to become the largest component of TasNetworks' capital expenditure proposal for the provision of standard control distribution services, accounting for around 89 per cent of total capital expenditure by the end of the next regulatory control period.

Figure 18-7 TasNetworks combined distribution and dual function proposed capex ($2019 million)



Source: TasNetworks, *Tasmanian Transmission and Distribution Regulatory and Revenue Proposals Overview*, January 2018, p. 24.

The increasing importance of replacement capital expenditure in the cost function has important implications for the design of cost reflective network tariffs, particularly in terms of signalling LRMC. [90]

Energy Consumption

Table 18-7 below shows the current AEMO medium term forecast of annual electricity consumption, that is, kWh, by NEM region.[91]

Table 5 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 CSG 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

[90] AER, *TasNetworks distribution final determination 2017–2019, Attachment 19 Tariff structure statement April 2017* p. 54.

[91] https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/NEM_ESOO/2017/2017-Electricity-Statement-of-Opportunities.pdf

- 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 in Tasmania is the adoption of Distributed Energy Resources. Table 18-8 provides a regional comparison of the cumulative installation of solar photovoltaic systems.

Table 6 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. 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 across the NEM, as shown in Table 18-9 below.[92] We consider this variation

[92] AEMC *2017 Residential Electricity Price Trends Report*. This publication is available from https://www.aemc.gov.au/markets-reviews-advice/2017-residential-electricity-price-trends

reflects a broad range of factors including differences in temperature conditions, the mix of appliances and the market penetration of gas for heating and electric cooking.

Table 7 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

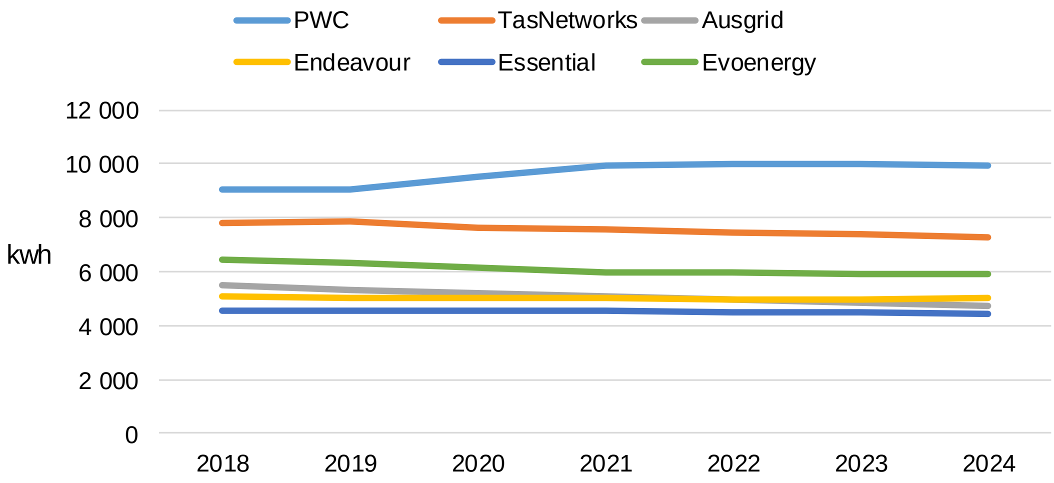
Source: AEMC, *2017 Residential Electricity Price Trends*, p. 62.

We note the following from the above table:

- the influence of colder temperatures have resulted in Tasmania and the Australian Capital Territory having the highest annual residential electricity consumption in Australia
- Victoria and New South Wales have the lowest annual residential electricity consumption in Australia 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).

Figure 18-8 provides a comparison of the indicative energy consumption per residential customer by selected distributors over the next regulatory control period.

Figure 18-8 Comparison of residential average consumption by distributor

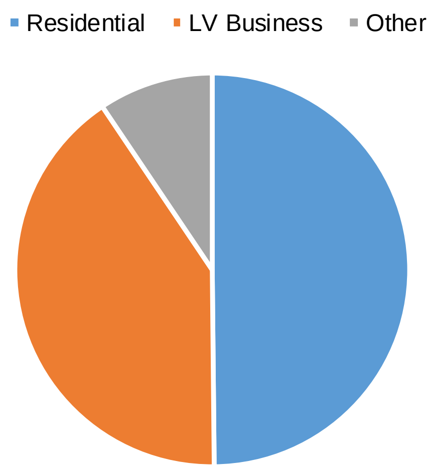


Source: AER analysis.

Key insights into TasNetworks energy consumption environment

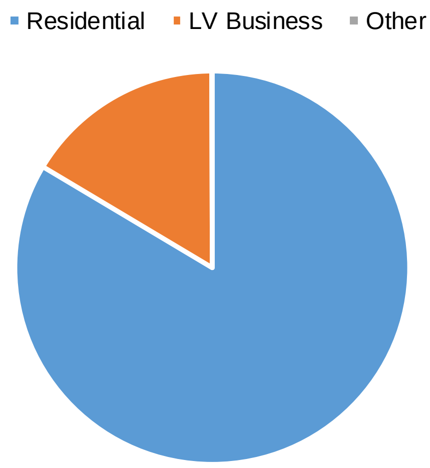
As with other jurisdictions, the residential and LV business segments in TasNetworks' network area have a high annual share of total energy consumption and total customers (see Figure 18-9 and Figure 18-10 below). The small number of customers on a confidential individually calculated network tariff consume around 8 per cent of TasNetworks annual total energy consumption.

Figure 18-9 TasNetworks annual energy consumption by tariff class (kWh)



Source: TasNetworks, *Annual Pricing Proposal 2018-19.*

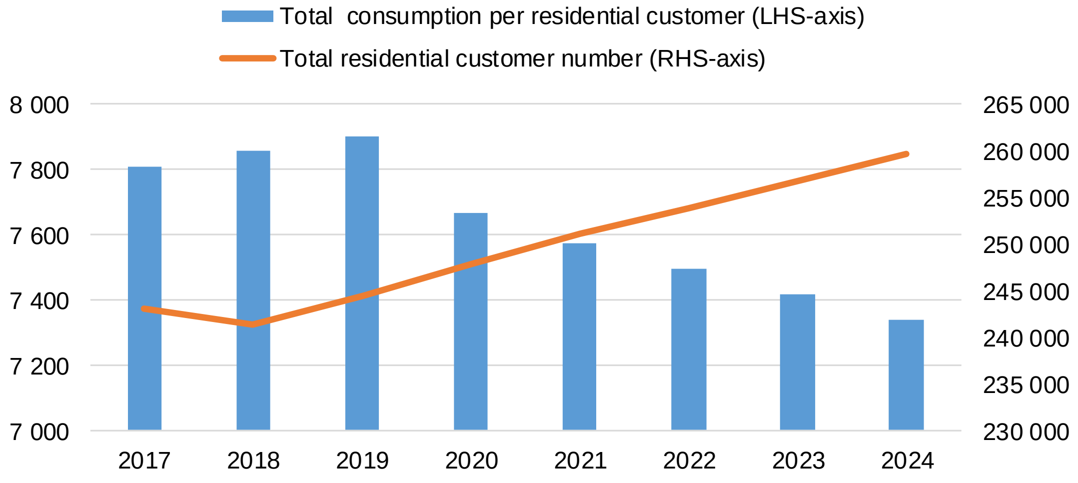
Figure 18-10 TasNetworks customer numbers by tariff class



Source: TasNetworks, *Annual Pricing Proposal 2018-19.*

Figure 18-11 compares the forecast trend for in the number of residential customers and the average energy consumption per residential customer in TasNetworks network area.

Figure 18-11 TasNetworks residential customer numbers and average consumption (kWh)

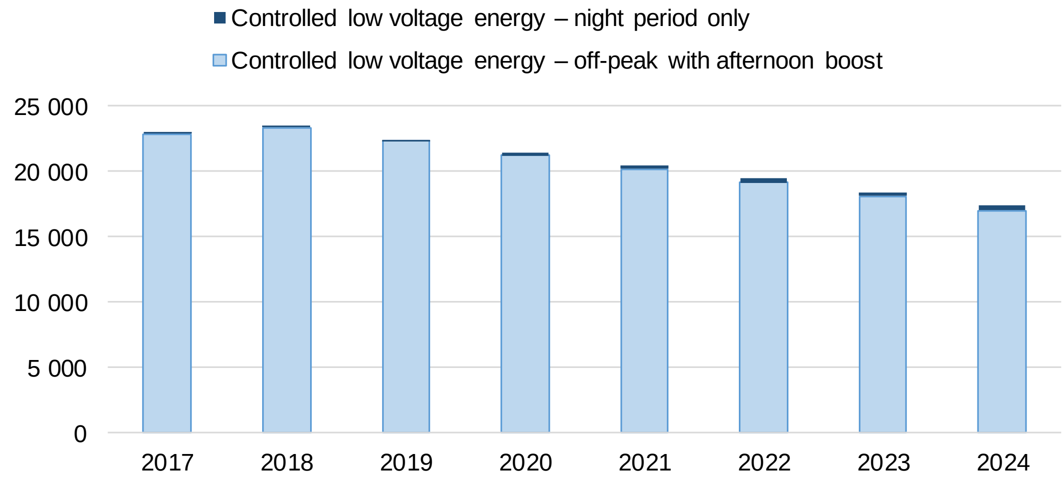


Source: AER analysis.

The forecast growth in the number of residential customers is driven mainly by moderate population growth, whereas the forecast decline in energy consumption per household reflects mainly the uptake of energy efficient appliances and the expected growth in solar PV installations under a net metering arrangement.

The following figure provides the forecast trend in annual number of customers assigned to controlled load tariffs over the next regulatory control period in TasNetworks area.

Figure 18-12 TasNetworks controlled load customer numbers



Source: AER analysis.

We consider the forecast decline in the number of controlled load customers in TasNetworks area is likely to reflect a range of factors, such as fuel substitution (e.g. switching to solar and gas hot water) as well as the introduction of cost reflective pricing where the network price charged for uncontrolled consumption outside the peak charging window is low – reducing the financial incentive of controlled load tariffs.

The other important insight is that the penetration of controlled load tariffs in the residential customer segment is low in TasNetworks area compared to most other jurisdictions.

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 period that tariffs are being reformed.

Unlike most other distributors, TasNetworks is responsible for the setting of network prices for transmission and distribution services in Tasmania.

Table 18-6 shows TasNetworks proposed smoothed revenue requirement for the provision of electricity transmission services over the next 5 year regulatory control period recovered from TasNetworks distribution customers.

Table 18-6 TasNetworks proposed revenue requirement 2019-24

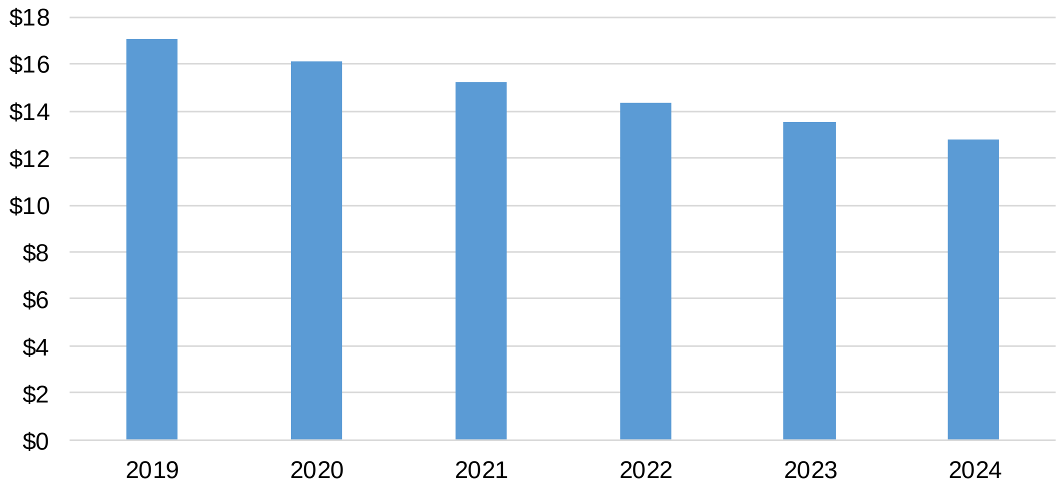
	2018-19	2019-20	2020-21	2021-22	2022-23	2023-24

Smoothed Transmission Revenue Requirement	172.9	164.4	156.3	148.6	141.3	134.3

Source: TasNetworks, *Tasmanian Transmission Revenue and Distribution Regulatory Proposal 2019-24, 31 January 2018*, p. 187.

Figure 18-13 below shows the forecast reduction in transmission revenue requirement is expected to result in a lower transmission charges in Tasmania over the next regulatory control period.

Figure 18-13 TasNetworks indicative average transmission prices (nominal - constant volume)



Source: AER analysis

Given the nature of transmission pricing, we consider the majority of TasNetworks' forecast reduction in transmission revenue requirement will flow through to the small number of large users that are directly connected to TasNetworks electricity transmission network. Nevertheless we consider a reduction in average transmission prices will mean a reduction in the transmission costs borne by the large number of customers connected to TasNetworks electricity distribution network.

TasNetworks has proposed a moderate real increase for the smoothed revenue requirement for its standard control distribution service during the next regulatory control period. Importantly, TasNetworks expects to recover materially less transmission costs from its electricity distribution customers over this period. As a result TasNetworks overall network revenue requirement in its capacity as a distributor is forecast to increase modestly in real terms in the next regulatory control period, as shown in Table 18-7 below.

Table 18-7 TasNetworks proposed revenue requirement 2019-24

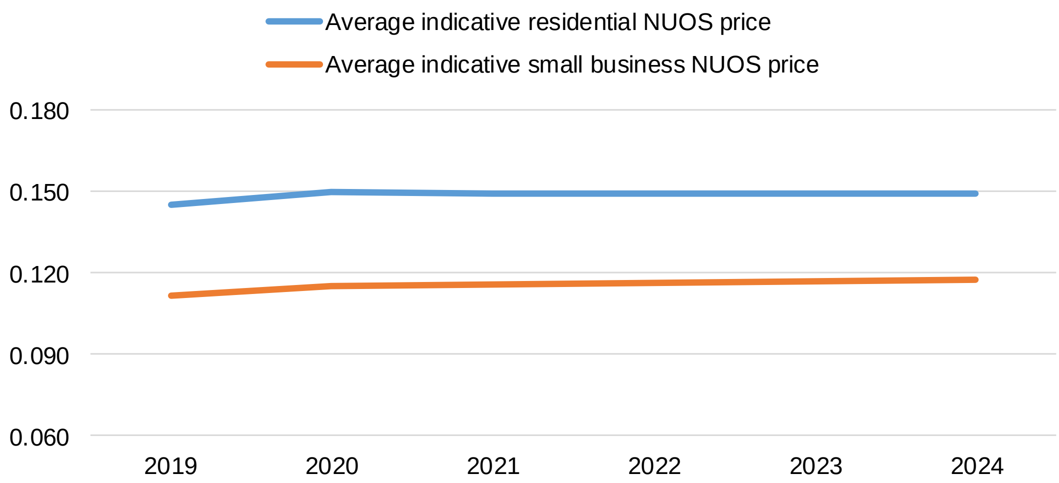
	2018-19	2019-20	2020-21	2021-22	2022-23	2023-24
Smoothed Distribution Revenue Requirement ($m)	241.6	246.9	252.6	258.5	264.4	270.6

Share of Transmission Revenue Requirement ($m)	90.9	89.8	85.8	82	78.3	74.8
Total Network ($m)	332.7	336.7	338.4	340.4	342.7	345.4

Source: TasNetworks, *Tasmanian Transmission Revenue and Distribution Regulatory Proposal 2019-24 31 January 2018*, p.190

The modest growth in network revenue requirement, together with modest growth in customer numbers and volumes will result in TasNetworks average NUOS prices being stable in real terms over the medium term, as shown in the figure below.

Figure 18-14 TasNetworks indicative average network prices ($ nominal)



Source: AER analysis.

We consider that the prospect of stable network prices and volumes, together with an expected increase in the penetration of interval metering, presents an opportunity for TasNetworks to make meaningful progress towards cost reflectivity under the customer impact principle in Chapter 6 of the NER.[93]

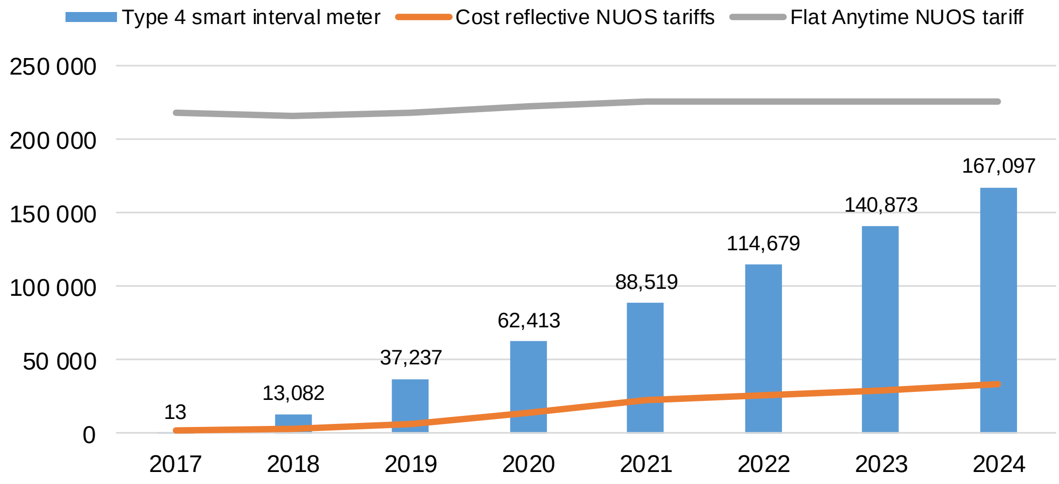
Interval metering penetration

The penetration of interval metering is a relevant factor to consider from a network pricing perspective because cost reflective network pricing can only be implemented for customers with an interval meter installed in their premise.

Figure 18-15 shows TasNetworks forecast of the number of interval meter installations and the number of residential customers on a cost reflective demand tariff over the next regulatory control period.

[93] NER, cl 6.18.5(h).

Figure 18-15 TasNetworks forecast number of interval metered residential customers



Source: AER analysis.

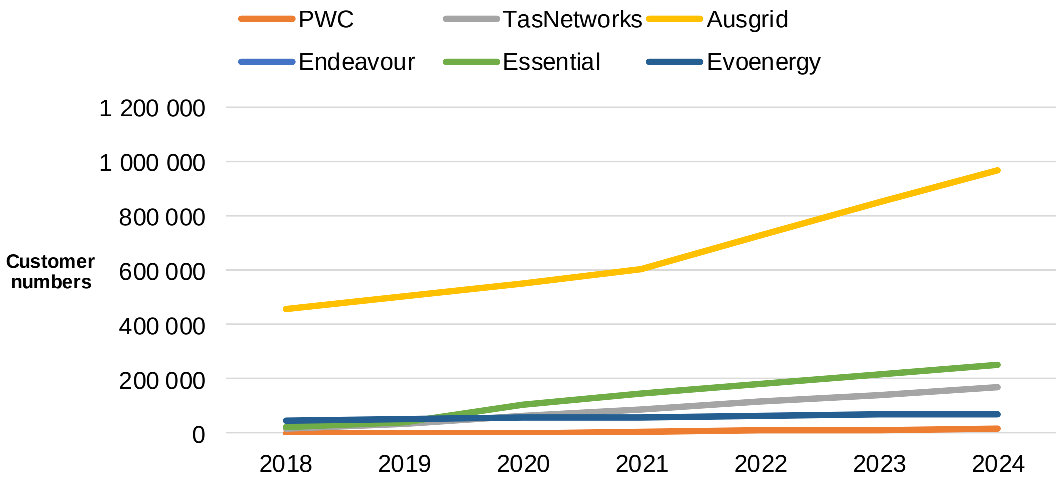
The figure above highlights that TasNetworks expects to see a marked increase in the penetration of interval metering in the residential customer segment. This technology will enable TasNetworks to introduce cost reflective pricing to a substantial proportion of its customer base over the medium to longer term.

Comparison of distributor interval metering penetration in the residential customer segment

Figure 18-16 below compares the forecast number of interval metered customers for 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 NER. [94]

[94] Australian Energy Market Commission, *National Electricity Amendment (Expanding competition in metering and related services) Rule 2015; National Energy Retail Amendment (Expanding competition in metering and related services) Rule 2015*, 26 November 2015.

Figure 18-16 Historical and forecast number of interval metered customers by distributor



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

The key points from the figure above are summarised below:

- TasNetworks Ausgrid and Essential Energy are forecasting to have significant increases in the residential customers with interval metering installed in their premise by the end of the next regulatory control period.
- Evoenergy, Essential Energy and Endeavour energy are all expected to have interval metering installed in around one third of their residential customer base by the endo of the next regulatory control period.
- Power and Water is expected to have the lowest penetration of interval metering in the residential customer segment with around a quarter of these customers having interval metering by the end of the next regulatory control period. We note Power and Water are the responsible entity for metering over this period.

Overview of proposed network tariff assignment procedures

The extent that a build-up in the penetration of interval metering translates to an increase in the number of customers on more cost reflective tariffs is dependent on distributors' network tariff assignment and re-assignment policies. Table 18-8 provides a comparison of the proposed tariff assignment policies for each distributor.

Table 18-8 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 (e.g. 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.
Power and Water	• Assign all new connections (with interval meters) to applicable demand tariff. • Re-assign existing customers that upgrade to an interval meter to applicable demand tariff.

Source: AER analysis.

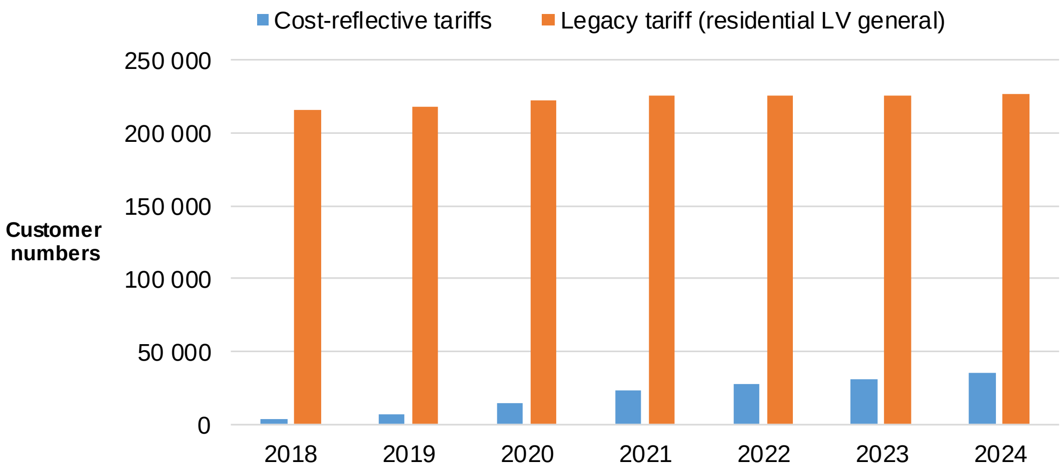
We note the following key points from Table 18-8:

- TasNetworks proposed tariff assignment policy based on voluntary opt-in to cost reflective tariffs in the next regulatory control period will result in 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 under the opt-in approach, it will take well over a decade to complete the transition to cost reflective pricing

- Evoenergy and PWC propose to assign to a cost reflective demand tariff for all new customers, and to existing customers who replace their basic accumulation meter with an interval meter. Evoenergy will allow customers on a demand tariff to voluntarily move to the Time of Use energy tariff
- Essential Energy propose to assign to a cost reflective demand tariff all new, and existing, customers that connect a solar PV system, battery or electric vehicle charger to the electricity network. An interval meter will be required in these instances
- Endeavour Energy proposes to assign all new, and existing, customers that upgrade to a 3 phase connection to a transitional demand tariff. However, such customers can voluntarily opt-in to the fully cost reflective demand tariff. Existing customers with a single phase connection that have their basic accumulation meter replaced with a Type 4 interval meter will remain on the anytime energy network tariff
- Ausgrid propose to assign to a cost reflective tariff 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.

In light of TasNetworks proposal to base its tariff assignment procedure on an opt-in approach to the introduction of cost reflective network pricing, the number of customers on a demand tariff is forecast to increase only moderately over this period, as Figure 18-17 below illustrates.

Figure 18-17 TasNetworks residential customers by tariff



Source: AER analysis

Interval metering penetration

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

The following table provides a summary of the current tariff classes for each distributor. It is clear from this analysis that there is a considerable variation in the extent of tariff class disaggregation across distributors, particularly in respect to customers connected at the low voltage level of the electricity network.

Table 18-9 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	Commercial low voltage	More than 750 MWh per annum
High voltage	High voltage	High voltage	High voltage	High voltage	High voltage
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.

The key highlight of the table above is TasNetworks approach to grouping of LV-connected customers into a much larger number of tariff classes based on a broad range of criteria, such as the nature of usage (e.g. residential vs irrigation), the availability of supply (e.g. controlled vs uncontrolled), the extent of usage (small vs large).

Network tariffs

NUoS tariffs in Australia typically comprise the following components:

- distribution use of system (DUoS) component – this 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 component 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 component only applies where a distributor 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.[95]

The following table 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 across tariffs.

Table 18-10 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

The following table shows the number of customers and NUOS revenue for the major tariffs for residential and small business customers by selected distributors in Australia.

[95] TasNetworks network use of system tariffs do contain a jurisdictional scheme amount component.

Table 18-11 Key statistics - current network tariffs

DNSP	Legacy Tariff: Network Tariff Name	Legacy Tariff: Number of Customers	Legacy Tariff: NUOS Revenue ($m)	Cost Reflective Tariff: Network Tariff Name	Cost Reflective Tariff: Number of Customers	Cost Reflective Tariff: NUOS Revenue ($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.

TasNetworks network tariffs

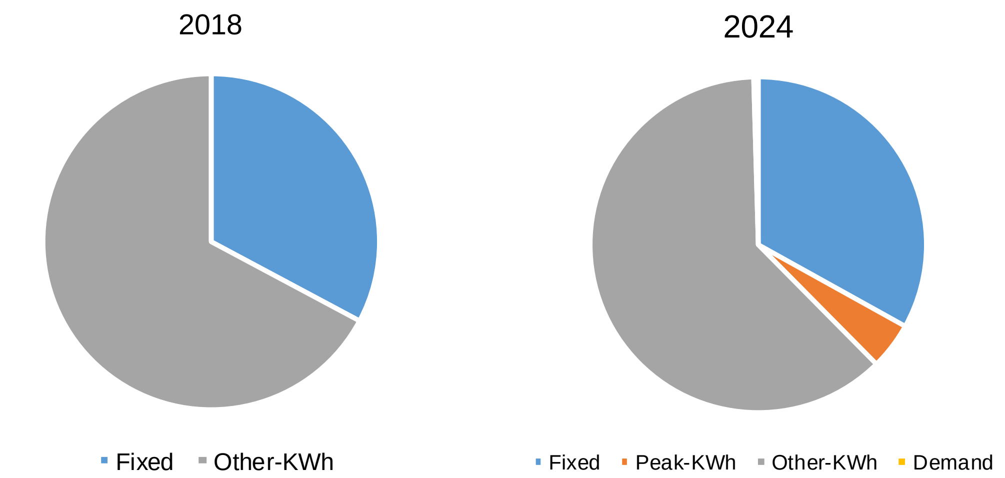
To fully understand TasNetworks' current network tariffs it is necessarily to look in more detail at the underlying level and structure of the tariffs at the DUoS and TUoS level.[96]

Distribution Use of System (DUoS) Tariffs

The following figure shows the annual DUoS revenue share by charging parameter type for the main residential tariffs.

[96] TasNetworks' network tariffs do not comprise a jurisdictional scheme component.

Figure 18-18 TasNetworks DUoS revenue share by charging parameter – major residential tariffs



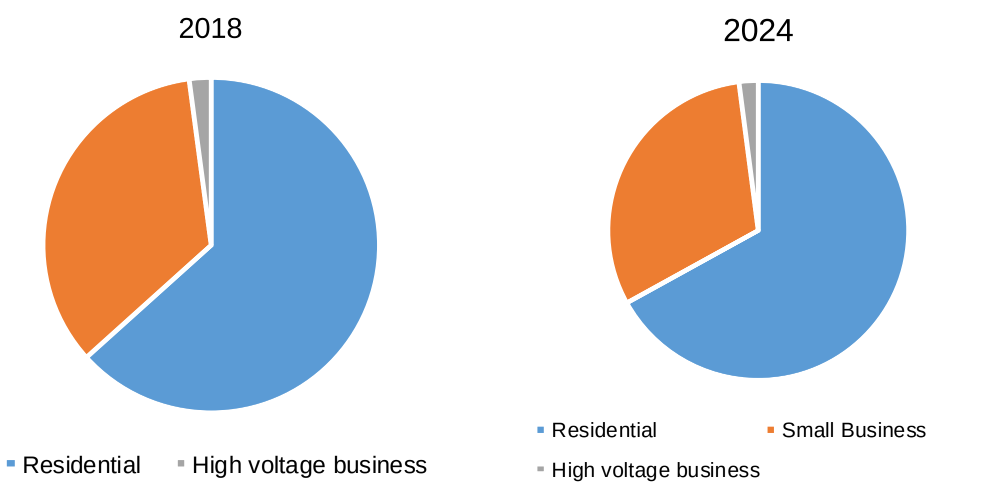
Source: AER analysis.

It is clear from the figure above that TasNetworks proposes to adopt a gradual approach to rebalancing its tariffs at the DUoS level during the next regulatory control period.

It is relevant to note that the modest reduction in the DUoS revenue share from non-peak energy charges and flat anytime charges from an estimated 67 per cent in 2018 to a forecast 62 per cent in 2024 is mainly an outcome of the forecast voluntary take-up of more cost reflective tariffs, rather than a re-balancing of DUoS prices.

The following figure compares annual DUoS revenue share by major customer segment in 2018–19 and 2023–24.

Figure 18-19 TasNetworks - DUoS revenue by key customer segment – 2019 to 2024



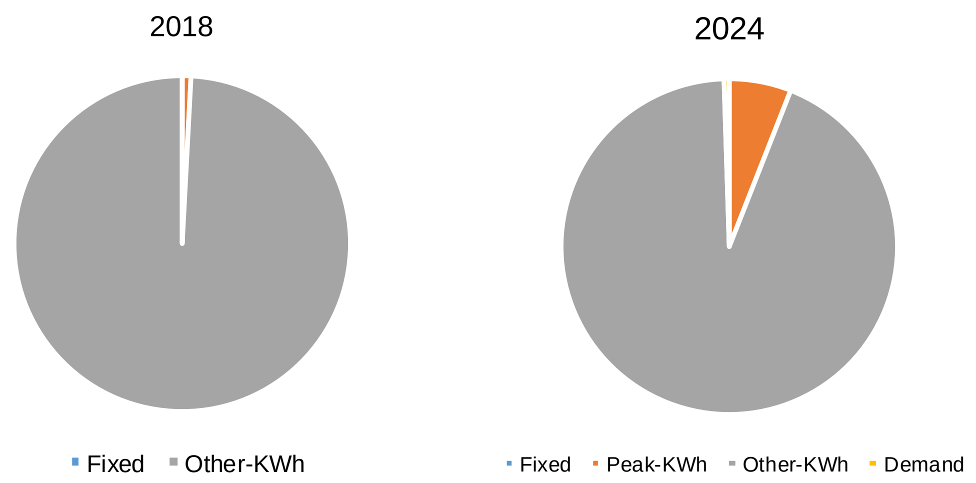
Source: AER analysis.

For the selection of network tariffs included in the AER analysis for the figure above, TasNetworks share of annual DUoS revenue is forecast to increase for residential customers from 63 per cent in 2018-19 to 67 per cent in 2023-24. As a result, the DUoS revenue share attributed to the small business customer segment is forecast to reduce from 35 per cent in 2018-19 to 31 per cent in 2023-24. No change in annual DUoS revenue share is forecast for the high voltage business customer segment.

Transmission Use of System Tariffs

The following figure shows the annual Transmission Use of System (TUoS) revenue share by charging parameter type for the main residential tariffs.

Figure 18-20 TasNetworks - TUoS residential revenue share by charging parameter



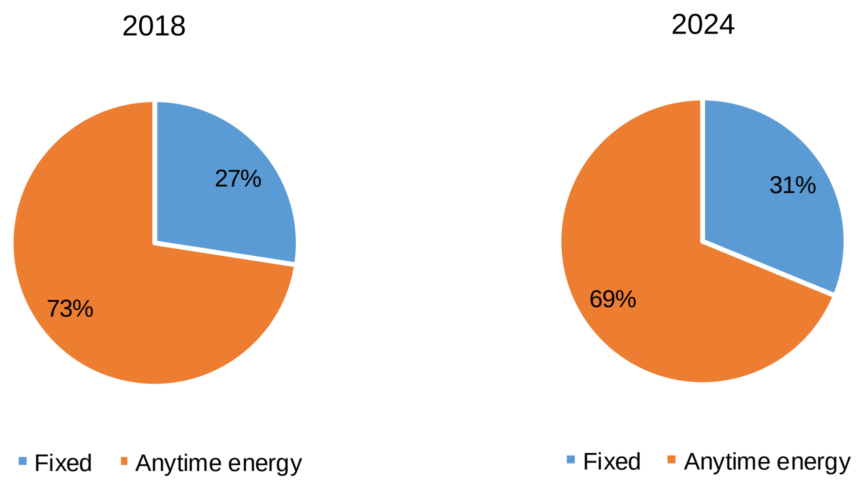
Source: AER analysis.

It is clear from the figure above that the current TUoS component of TasNetworks main residential network tariffs is predominantly based on energy consumption, which is not cost reflective. TasNetworks proposes to begin to address this issue by re-balancing TUoS revenue from anytime energy charges towards demand charges – an outcome of the expected increase in penetration of demand tariffs.

Network Use of System Tariffs

Reflecting the underlying changes at the DUoS and TUoS level, Figure 18-21 below shows the change in the annual NUoS revenue share over the regulatory control period by charging parameter type for the legacy tariffs for residential and small business customers.

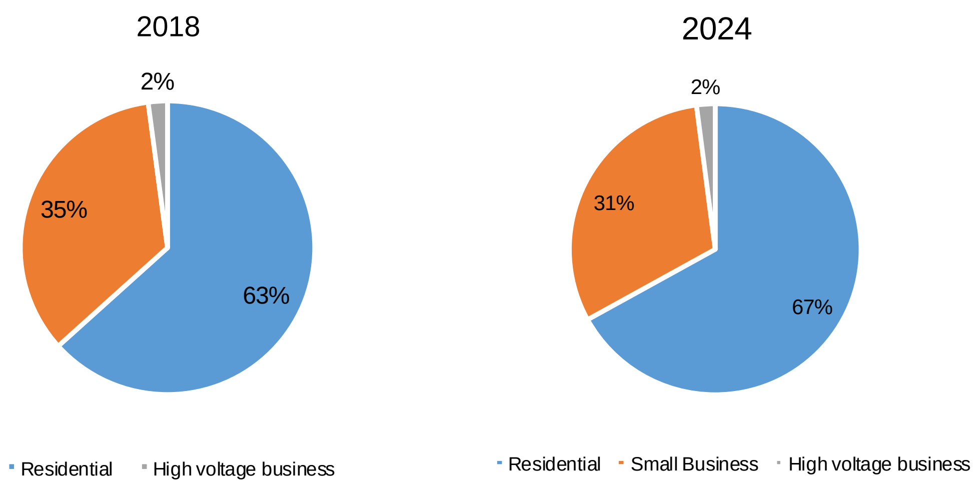
Figure 18-21 TasNetworks legacy tariffs NUOS revenue share by customer segment



Source: AER analysis.

Figure 18-22 shows the changes in NUoS revenue share by customer segment over time.

Figure 18-22 TasNetworks NUoS revenue share by customer segment

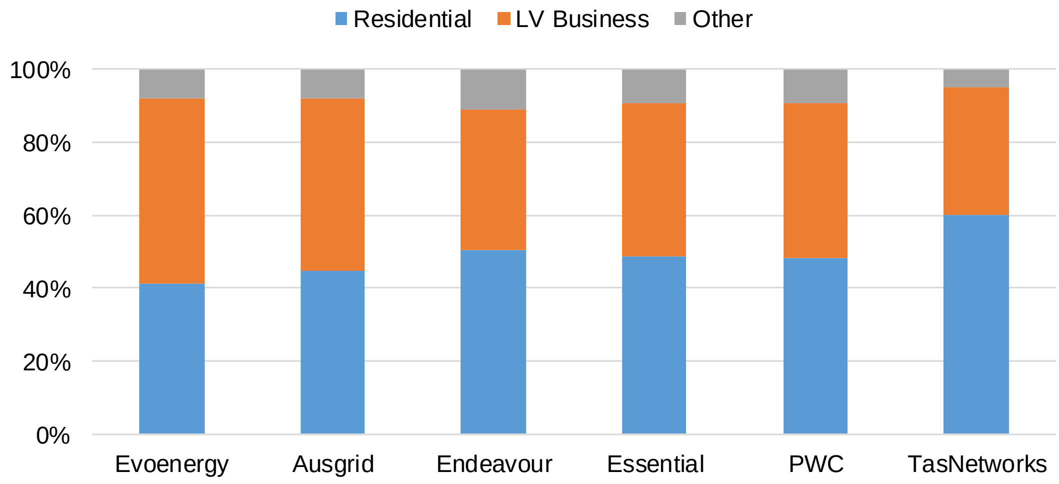


Source: AER analysis.

The figures above shows that the annual share of residential NUoS revenue is expected to increase over the next regulatory control period, reflecting TasNetworks' strategy of eliminating the discount applied to the uncontrolled heating tariff (TAS41) and the forecast gradual adoption of the more cost reflective demand tariff.

It should also be noted that TasNetworks' tariff reform proposals should be considered in the context of its relatively high reliance on residential customers from a NUoS revenue perspective, as highlighted in the figure below.

Figure 18-23 NUoS revenue share by customer segment and distributor - 2018



Source: AER analysis.

TasNetworks indicative rate of re-balancing NUoS tariffs in the residential customer segment over the next regulatory control period is modest. Nonetheless, it is comparable with many other distributors, as discussed in the following section.

Insights into the economic efficiency implications of tariff reform proposals

From a regulatory compliance perspective, the AER is focused on whether the network pricing approach set out in TasNetworks' TSS proposal contributes to compliance with the distribution pricing principles and to the achievement of the network pricing objective. Compliance with the distribution pricing principles in the NER requires that the distributor make progress towards LRMC-based pricing and the efficient recovery of residual costs. These issues are explored below.

Progress towards efficient recovery of residual costs

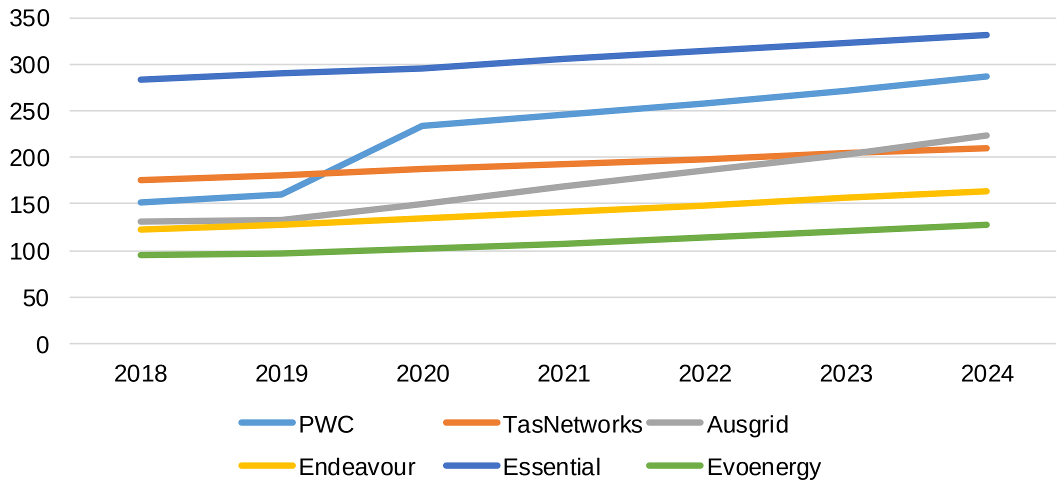
The efficient recovery of residual costs requires that these costs are recovered from network customers in a manner that minimises the distortion to efficient network usage.

The fixed charge has the potential to be an economically efficient way to recover these costs because changes in the level of the fixed charge do not typically influence the investment, network connection and consumption decisions of electricity distribution customers. Nevertheless it is important from a compliance perspective that the rate of fixed charge increases does not contravene the customer impact principle in the NER.[97]

[97] NER, cl 6.18.5(h).

The figure below provides insights into the extent that the distributors propose to increase the level of the fixed charge of their residential legacy tariff in the next regulatory control period.

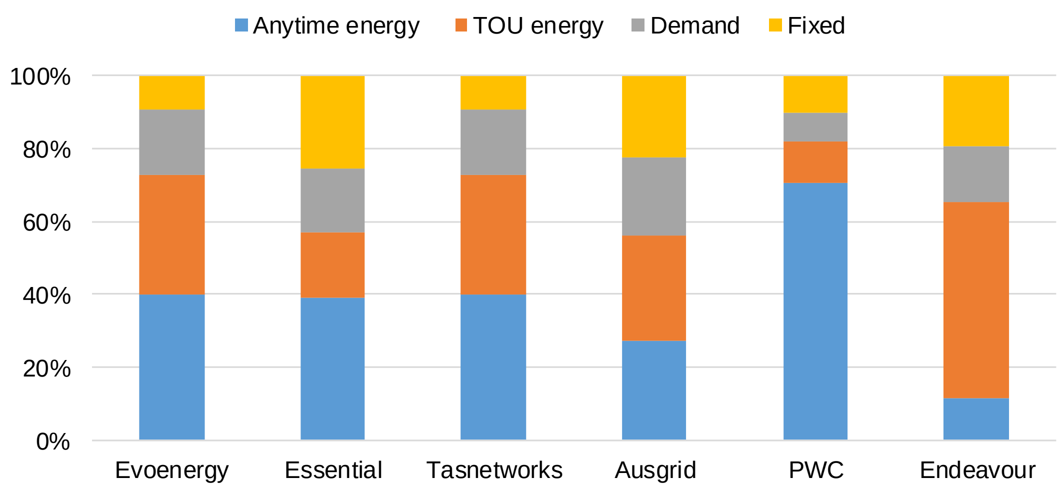
Figure 18-24 Distributor comparison - Fixed charges residential legacy tariff ($ per annum)



Source: AER analysis.

The above comparison reveals that Ausgrid, PWC and Essential Energy propose to increase their reliance on fixed charges with significant increases in the level of fixed charge expected over the next regulatory control period. TasNetworks, Evoenergy and Endeavour Energy propose to apply only modest increases to the fixed charge over this outlook period.

Figure 18-25 Distributor comparison network revenue share by charging parameter



Source: AER analysis.

The figure above shows that the current reliance on anytime energy charges from a NUoS revenue perspective varies markedly across individual distributors.

PWC and Endeavour Energy are estimated to have the highest reliance on anytime energy charges, whereas Ausgrid will have the lowest reliance in line with their relatively high penetration of cost reflective pricing in the residential and small business customer segment.

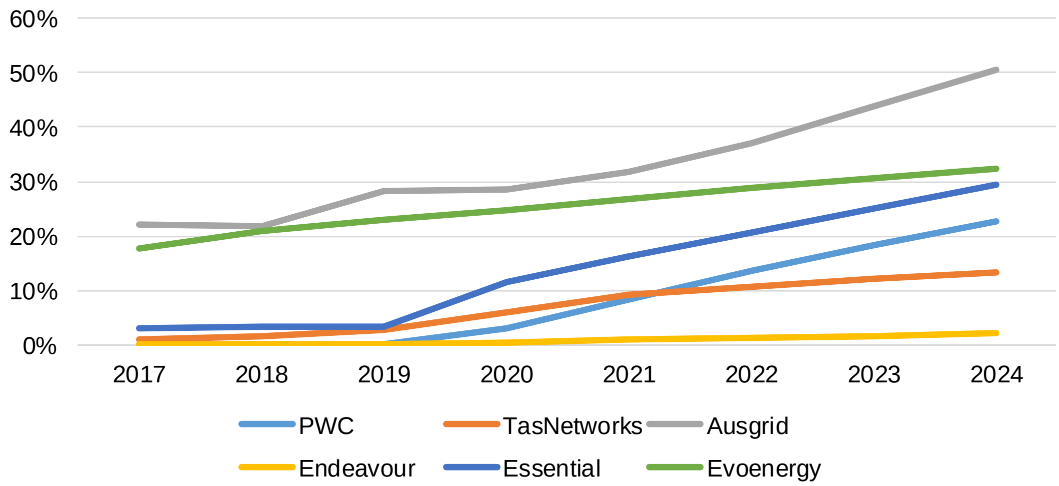
Progress towards LRMC-based pricing

Consistency with this aspect of the distribution pricing principles set out in the NER can be achieved in a number of ways, such as:

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

TasNetworks proposes to adopt an opt-in approach to the introduction of more cost reflective demand tariffs for residential and small business customers. As a result of this policy, the proportion of its residential customers on a cost reflective demand tariff in TasNetworks network area is expected to grow only moderately over medium term, see Figure 18-26 below.

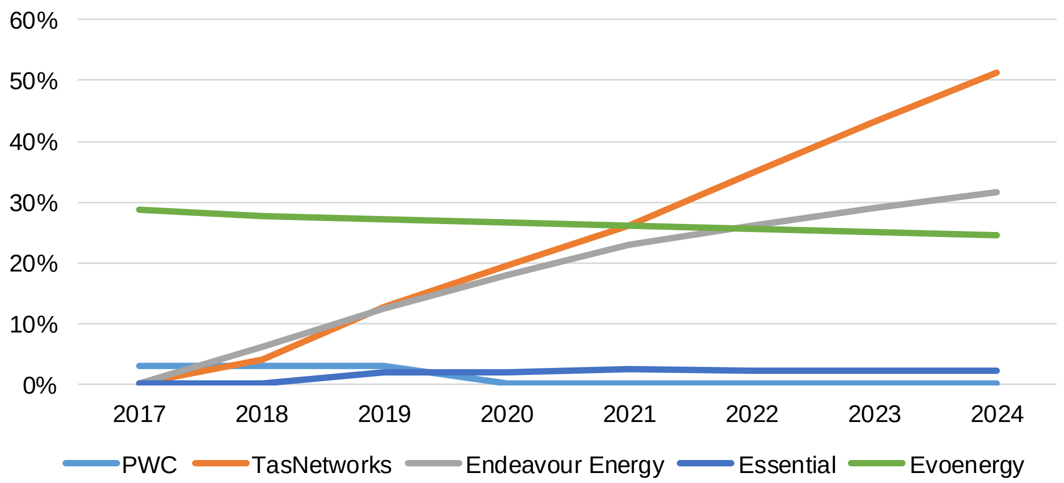
Figure 18-26 Annual penetration of cost reflective pricing in residential segment



Source: AER analysis.

The following figure provides a comparison across distributors of the percentage of residential customers on a non-cost reflective network tariff with an interval metered installed in their premise.

Figure 18-27 Interval meter penetration on non-cost reflective tariff by distributor



Source: AER analysis.

It can be seen that Endeavour Energy, TasNetworks and Evoenergy will have a significant proportion of their interval metered residential customers assigned to a non-cost reflective network tariff by the end of the regulatory control period.

It is interesting to note that unlike other distributors, Endeavour Energy and TasNetworks expect to see an increasing proportion of their residential customers with interval metering remain on the non-cost reflective network tariff over the next regulatory control period. This forecast outcome reflects that Endeavour Energy and TasNetworks proposes to allow relatively more of their interval metered customers to remain assigned to their existing anytime energy network tariff, rather than being assigned to a more cost reflective tariff.

Transmission Pricing

Unlike most other distributors, TasNetworks is also responsible for the setting of annual transmission charges in Tasmania.

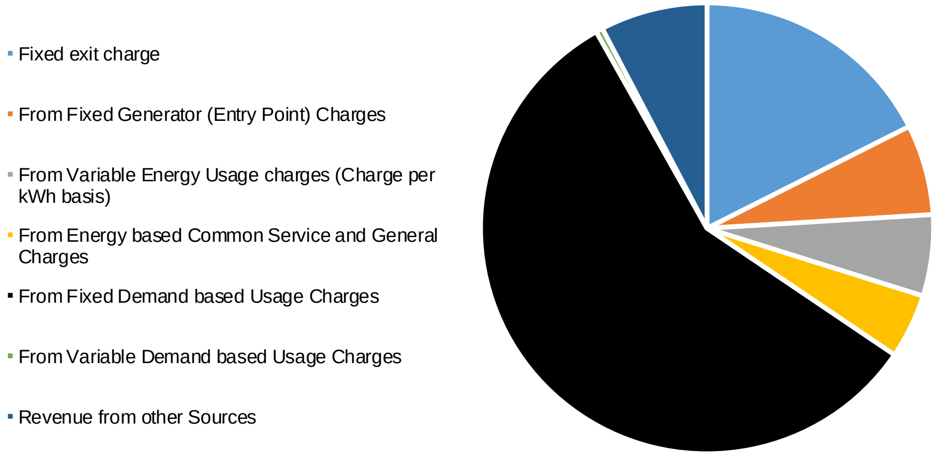
These charges are calculated and applied on a location-specific basis, and compliance with the TasNetworks transmission pricing methodology and Chapter 6A of the NER, is required.

TasNetworks is not able to pass through the transmission price signal for the majority of its distribution customers, due mainly to the prevalence of basic accumulation metering and the reliance on “postage stamp” pricing[98] for the published network tariffs for interval metered business customers. This disparity between transmission charges

98 Distributors charge customers the same tariffs across their networks, regardless of location this is often referred to as postage stamp pricing.

and the TUoS prices set by TasNetworks in its capacity as a distributor is reflected in the following figure.

Figure 18-28 TasNetworks transmission revenue share by charging parameter



Source: AER analysis.

TasNetworks does set the TUoS prices in its capacity as a distributor for large business customers assigned to an Individually Calculated Tariff to reflect to some extent the location-specific transmission price signal.

Retail Electricity Pricing

Generally, all residential and small business energy pricing offers are either a standing offer or a market offer.[99] The key difference between the two offers is the terms and conditions in the contract, and the resulting price.

In jurisdictions with price regulation, such as Queensland, Tasmania and the Northern Territory, 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 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.[100] Some retailers have innovated in the tariff

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[99] 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.

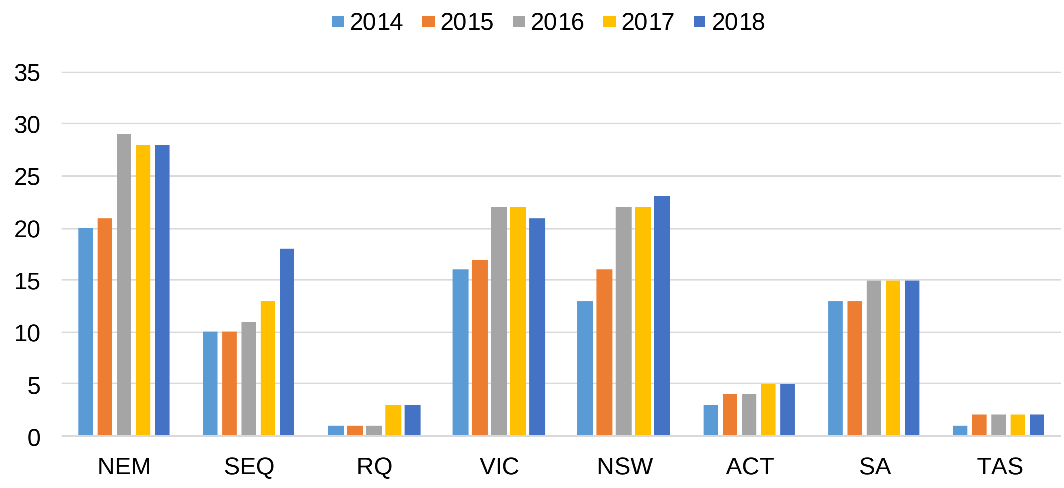
[100] Refer to Glossary section for a definition of block tariff and time of use tariff structures.

structures that they offer, such as the fixed payment plan offered to residential customers by Origin Energy.[101]

Electricity retail market concentration by jurisdiction

As of March 2018, there were a total of 28 active electricity retailers in the NEM.[102] Tasmania has the least number of active electricity retailers of all jurisdictions, see figure below:

Figure 18-29 Active electricity retailers in National Electricity Market



Source: AEMC 2018 Retail Energy Competition Review.

Comparison of annual electricity supply chain costs by jurisdiction

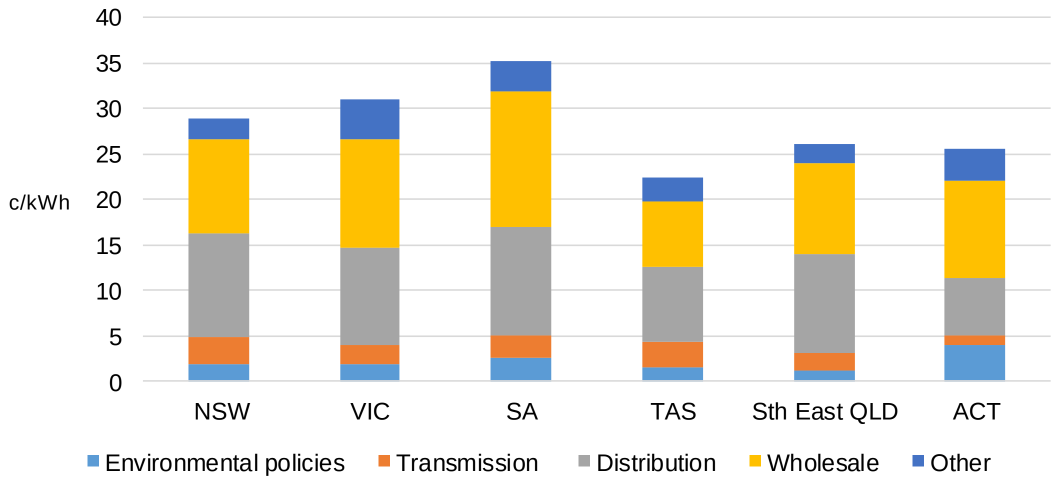
Retail electricity prices reflect the underlying costs in the supply chain, such as the costs of providing regulated electricity network services, retail margin, electricity purchase costs and the costs relating to environmental policy.

The following figure shows an estimate of the supply chain cost components, expressed on an average cents per kWh basis, that underlie the annual retail electricity bill for a representative residential consumer by NEM region.

[101] 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

[102] Note: the AEMC defines a electricity retailer to be active if they have more than 50 customers. For more information, refer to Section 3 of the AEMC Review of Competition Report. This report is available from the following link https://www.aemc.gov.au/sites/default/files/2018-06/Final%20Report.pdf

Figure 18-30 Annual Electricity Supply Chain Costs by NEM region



Source: AEMC, *Retail Competition Review 2018.*

We note from the figure above that the wholesale energy purchases and the provision of electricity distribution and transmission services are the largest cost components in the underlying supply chain. Nevertheless, there is considerable variation in the relative share of each supply chain cost component across NEM regions. For example, the annual cost of environmental policy is the highest in the Australian Capital Territory, whereas wholesale energy purchase costs for the representative customer are highest in South Australia.

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.

The table below 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.[103]

Table 18-12 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

[103] Refer to : www.energymadeeasy.gov.au

Adelaide	69	2,676 – 4,588	2,895
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, *Draft report: Standing offer prices for the supply of electricity to small customers from 1 July 2017*, March 2017, p.61

We consider the key point from the above table is 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 in each jurisdiction.

Tasmanian retail market

Tasmania's electricity market is a relatively small market to the rest of the NEM with currently around 280,000 small customers. It also has the smallest gas market in Australia, reflecting the roll-out of the state's gas network targeted large users as well as geographic barriers.

Since 1 July 2014, all residential and business customers in Tasmania have the choice of staying with Aurora Energy[104] 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 Aurora Energy's regulated standard offer tariff. The Office of Tasmanian Economic Regulator (OTER) determines the maximum price that Aurora Energy can charge its regulated customers.

Tasmania remains highly concentrated despite having introduced full retail contestability. Aurora Energy is the only retailer active in the residential customer segment and competes with ERM Business Energy in the small business customer, commercial and industrial customer segments. There were also two gas retailers, Aurora Energy and TasGas, currently supplying only around 14,000 customers. The AEMC analysis of the structure of the Tasmanian electricity market found that with an estimated Herfindahl-Hirschman Index (HHI)[105] value of close to 10,000 it is a highly

[104] Aurora Energy is fully owned by the Tasmanian Government. Momentum Energy is also owned by the Tasmanian Government, but does not operate as a retailer in Tasmania.

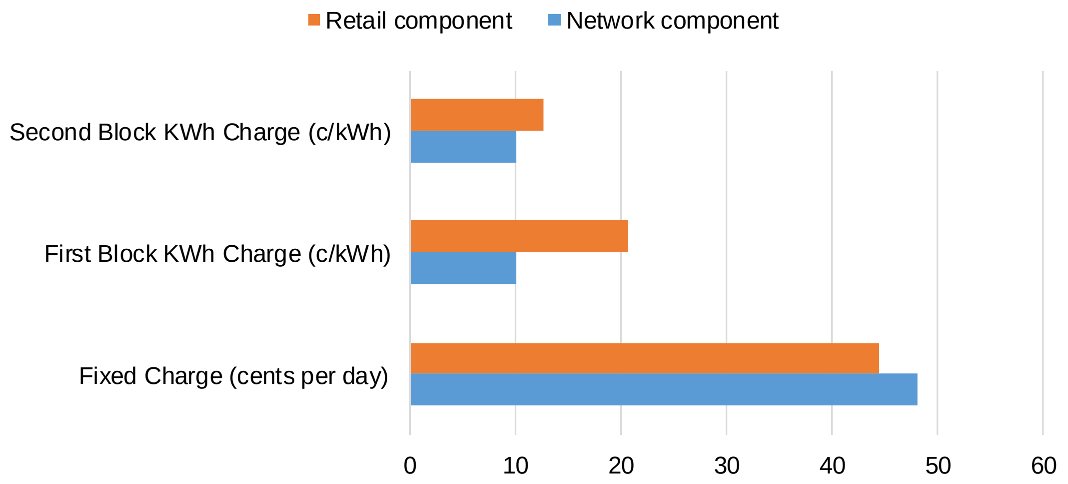
[105] This index is a commonly accepted measure of market concentration that is used to determine market competitiveness.

concentrated business market and operates essentially as a regulated monopoly in the residential market.[106]

Retail pricing behaviour

The underlying network tariff structure is typically reflected in Aurora Energy's standard retail tariffs for residential and small business customers (less than 150 MWh pa). The only exception is the Low Voltage Business General Anytime Energy Tariff (Tariff 22), where the network tariff comprises a single anytime energy charge, whereas Aurora Energy has adopted a declining block anytime energy charge structure at the retail level (see figure below).

Figure 18-31 Aurora Energy's mismatch of anytime energy structure - network and retail



Source: AER analysis.

Aurora Energy does not yet offer a standard retail tariff offer in relation to the recently introduced TasNetworks' network demand tariff for residential customers (Tas87). Aurora Energy does, however, currently offer a standard retail kVA demand tariff for Low Voltage business customers (Tariff 82).

Other unique features of retail electricity pricing in Tasmania

There is around 20,000 customers on a Pay As You Go tariff in Tasmania. This tariff is a prepaid electricity service that enables customers to purchase electricity top-up credits for any amount between $5 and $200 at Aurora Energy's PAYGO agent locations throughout Tasmania. By purchasing credit in advance these customers know what they are spending on their electricity as they spend it – thereby assisting

[106] Note: On 30 April 2017, the Tasmania government announced it will cap wholesale electricity prices at $83.79 per MWh for 12 months from 1 July 2017 to protect households and small businesses from a massive spike in energy costs.

these customers to avoid electricity bill shock. The Aurora Energy's PAY AS YOU GO meter displays the credit you have at all times. It helps you take advantage of cheaper electricity rates at different times of the day and displays when it's time to purchase more credits.[107]

Aurora Energy currently offers its customers with a PAYGO meter a free upgrade to an advanced Type 4 interval meter.

107 The meter has $18 Emergency Credit to ensure you are not without power if you cannot immediately get to an authorised Aurora PAY AS YOU GO Recharge Agent to recharge your Smart Card.

B Tariff design and assignment policy principles

Under the NER, the objective of tariff reform is to introduce cost reflective pricing.[108] 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;
- 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 NER 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[109]
- contemplate whether customers are going to be able to understand the charges they are likely to see.[110]

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 our 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?

When should tariff assignment happen?

[108] NER cl 6.18.5(a).

[109] NER cl. 6.18.5(h).

[110] NER cl. 6.18.5(i).

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. We regulate 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).[111]

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.[112] If distributors adopt the same (re)assignment triggers there will be a more regular and consistent pace of tariff reform across distributors and jurisdictions.

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.[113]

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

[112] NER cl. 6.18.5.

[113] 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

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[114] and investment in energy efficiency in the construction of a new building/premise[115]
- 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.[116]

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 18-13).

Table 18-13 Distributor's proposed reassignment triggers

	New meter	Embedded generation	3-phase power	Batteries	Electric vehicles
Ausgrid	✓				
Endeavour Energy		✓	✓		
Essential Energy	✓	✓	✓	✓	✓
Evoenergy	✓				
Power and Water	✓				

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.

114 See D.4.1.

115 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

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

We note that the AEMC’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 AEMC'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 NER, 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.[117]

Each distributor, except TasNetworks, proposed default assignment to cost reflective tariffs in the Tariff Structure Statements we received in the first half of 2018.[118]

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.[119] They give the retailer the ability to face flat energy charges. These charges are easy to understand and manage for customers.[120] 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.

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

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

119 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.

120 NER cll. 6.18.5(h) and 6.18.5(i).

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 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.[121] 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 (achieved 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.[122] 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:

- 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.

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

122 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.

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, our 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 NEM 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.[123]

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.[124] However, as noted earlier, the Northern Territory Government regulates and subsidises retail electricity prices.[125] 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

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

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

[125] Electricity Pricing Order under section 44(8) of the *Electricity Reform Act (NT)* in accordance with 13A(d) of the *Electricity Reform (Administration) Regulations,* 6 June 2017.

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.[126]

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 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.[127] Essential Energy also proposed this approach for customers with new technology.[128]

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

[127] ActewAGL, *Revised Tariff Structure Statement,* Overview Paper, 4 October 2016, p. 18.

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

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 tariff with a pre-defined peak period and reinforces 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
- 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 us 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)[129]

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.

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;

129 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. Productivity Commission, *Electricity Network Regulatory Frameworks*, 9 April 2013, p. 337.

- 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;
- 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.[130]

The residential time of use energy tariff designs proposed by distributors are summarised in Table 18-14 below.

[130] 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 18-14 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).[131]

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.

[131] 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[132]
- 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.[133]

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 18-15.

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[132] 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.

[133] 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 18-15 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.[134] As above, the ACCC also made this observation.

The NSW distributors provided us 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:

[134] 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
- 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[135] and customers' ability to understand tariffs[136] 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.[137] By comparison, Endeavour Energy's proposed demand charge would cover over 1,000 hours a year,[138] and Ausgrid's seasonal peak time of use energy tariff would cover over 800 hours a year[139]
- 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[140]
- the extent to which costs vary between different locations.[141]

Therefore, if distributors were to propose critical peak pricing or prices that vary by location, there is scope for us 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.[142] Energex and Ergon Energy are both offering

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[135] NER, cll. 6.18.5(e)(f) and (g).

[136] NER, cl. 6.18.5(i).

[137] Productivity Commission, *Electricity Network Regulatory Frameworks,* 9 April 2013, p. 16.

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

[139] 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.

[140] NER cl. 6.18.5(f)(2).

[141] NER cl. 6.18.5(f)(3).

[142] 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[143]

- 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.[144]

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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[143] 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.

[144] 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 18-16 below.

Table 18-16 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 18-17 below.

Table 18-17 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 us with 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 NER there is no explicit requirement for consistency between distributors. However, the NER 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 NER 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.[145]

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.[146] 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.[147] 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’
- 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.[148] 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 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

145 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.

146 NER, chapter 10 Glossary.

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

148 NER, cl. 6.18.5(f).

from tariffs reflecting only LRMC.[149] 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.[150] 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.[151] 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[152]
- used a minimum of 10 years of forecast data in the calculation of LRMC[153]
- continued to refine their methods for estimating LRMC so their tariffs better reflect efficient costs.[154]

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 tariff structure statement 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:[155]

- 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

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

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

151 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.

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

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

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

155 NER, cl 6.18.5(f).

- the location of customers and the extent to which costs vary between different locations in the distribution network.[156]

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

- 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.[157] 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.[158]

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156 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.

157 NER, chapter 10—Glossary.

158 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.[159] Marginal cost refers to the cost of an incremental change in demand.[160] 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.[161]

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'.[162]

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.[163]

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

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

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

161 See attachment 19 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).

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

163 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.[164]

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;[165] and/or
- explored the use of other estimation methods, such as the Turvey approach.

Assessment criteria:

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. 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 NEM 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 approach, or utilising more

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

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

sophisticated approaches, such as the Turvey approach if they consider it appropriate.[166]

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.[167]

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.[168] 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:

- **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).[169] 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.[170]

  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).[171] Accordingly, basing tariffs on an estimate of average LRMC or a part of the network's LRMC sends

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

167 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.

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

169 Such as demand charges or time of use charges.

170 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.

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

inefficient price signals to most, if not all, customers.[172]

Postage stamp pricing is less costly and simpler to administer for distributors and retailers than locational pricing.[173] 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.[174] Distributors are transitioning their tariffs toward their LRMC estimates having regard to customer impacts.[175]

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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172 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.

173 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.

174 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)).

175 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.[176] 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 NEM.[177] 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.[178]

  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.[179]

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

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[176] NER, cl 6.18.5(f)(1).

[177] 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 16: Alternative control services*, September 2018.

[178] 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.

[179] 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).[180] It also provided Endeavour Energy with further information regarding the appropriate LRMC estimate on which to base its prices.[181]

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.[182] 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.[183]

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.[184] 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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180 NER, cl 6.18.5(f)(3).

181 NER, cl 6.18.5(f).

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

183 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.

184 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 TasNetworks' retail customers for direct control services.[185] We approve TasNetworks 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. TasNetworks' customers will be taken to be "assigned" to the tariff class which TasNetworks was charging that customer immediately prior to 1 July 2019 if:
   (a) they were a TasNetworks customer prior to 1 July 2019, and
   (b) they continue to be a customer of TasNetworks 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, TasNetworks becomes aware that a person will become a customer of TasNetworks, then TasNetworks 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, TasNetworks will take into account one or more of the following factors:
   (c) the nature and extent of the customer's usage
   (d) the nature of the customer's connection to the network
   (e) 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, TasNetworks, when assigning or reassigning a customer to a tariff class, will ensure the following:
   (f) that customers with similar connection and usage profiles are treated on an equal basis
   (g) those customers who have micro–generation facilities are treated no less favourably than customers with similar load profiles but without such facilities.

[185] 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. TasNetworks may reassign an existing customer to another tariff class in the following situations:

    (h) TasNetworks receives a request from the customer or customer's retailer to review the tariff to which the existing retail customer is assigned; or

    (i) TasNetworks 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 TasNetworks may reassign that customer to another tariff class.

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

6. TasNetworks 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 TasNetworks and that the customer or customer's retailer may object to the proposed reassignment. This notice must specifically include:

    (j) a written document describing TasNetworks' internal procedures for reviewing objections, if the customer's retailer provides express consent, a soft copy of such information may be provided via email

    (k) that if the objection is not resolved to the satisfaction of the customer or customer's retailer under TasNetworks 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

    (l) that if the objection is not resolved to the satisfaction of the customer or customer's retailer under TasNetworks 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, TasNetworks receives a request for further information from a customer or customer's retailer, then it must provide such information within a reasonable timeframe. If TasNetworks 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 TasNetworks about the proposed assignment or reassignment, TasNetworks must reconsider the proposed assignment or reassignment. In doing so TasNetworks 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 TasNetworks as part of the next network bill.

11. If a customer or customer's retailer objects to TasNetworks' tariff class assignment TasNetworks 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. TasNetworks must make available information on tariff classes and dispute resolution procedures referred to in paragraph 7 above to retailers operating in TasNetworks' distribution area.

13. If TasNetworks 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 TasNetworks 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 TasNetworks about the proposed assignment or reassignment, TasNetworks must reconsider the proposed assignment or reassignment. In doing so TasNetworks 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 TasNetworks 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, TasNetworks will set out in

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