DRAFT DECISION

Endeavour Energy
Distribution determination

2019 to 2024

Attachment 18
Tariff structure statement

November 2018

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Note

This attachment forms part of the AER's draft decision on the distribution determination that will apply to Endeavour Energy for the 2019–24 regulatory control period. 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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Glossary of terms

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

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

Term	Interpretation
	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 Endeavour Energy's (Endeavour) 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 should describe 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 is designed to provide consumers and retailers with certainty and transparency in relation to how and when network prices will change.

This should enable 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 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 during a five year regulatory control period.

Making tariff structures work for consumers

This is Endeavour's second tariff structure statement and applies to the 2019–24 regulatory control period. It must comply with the National Electricity Rules' (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.

Our final decision on Endeavour Energy's first tariff structure statement, which applies from 1 July 2017 to 30 June 2019, noted that transitioning to cost reflective pricing will take multiple regulatory control period to achieve.[3]

We set an expectation that to achieve ongoing compliance with the NER, each successive proposed tariff structure statement should put forward additional reforms.[4]

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1 NER, 6.18.1A(a).

2 NER, cl. 6.18.5.

3 AER, *Final Decision: Tariff structure statements: Ausgrid, Endeavour and Essential Energy*, February 2017, p. 20.

In our final decision on Endeavour's 2017–19 tariff structure statement, we stated that some elements of its tariff structure statement proposal, although compliant with the distribution pricing principles, would benefit from further consideration in future. [5]

Specifically, to provide guidance to NSW distributors for their 2019–24 tariff structure statements, we previously identified that they should:[6]

- increase the integration between network pricing, network planning and demand management strategies
- develop assignment policies to increase the speed of transition to cost reflective tariffs
- revise charging windows to more closely reflect the times of network congestion
- refine the method for estimating long run marginal cost (LRMC), including the inclusion of replacement capital expenditure (capex) within marginal cost estimates
- reconsider the use of a 30-minute window per month to measure customer demand.

18.1 Endeavour Energy's proposal

Endeavour's proposed 2019–24 tariff structure statement seeks to continue the pricing reform commenced as part of the 2017–19 tariff structure statement by:

- shortening its peak charging window to reflect the timing of peak demand in the more capacity constrained parts of its network[7]
- moving to an opt-out tariff assignment policy[8]

Endeavour also proposed to:

- introduce demand tariffs accompanied with flat energy charges instead of its existing time of use energy tariffs[9]
- simplify its tariffs by offering the same, demand tariff structure to all its residential and business customers.[10]

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4 AER, *Final Decision: Tariff structure statements: Ausgrid, Endeavour and Essential Energy*, February 2017, pp. 20-21.

5 AER, *Final Decision: Tariff structure statements: Ausgrid, Endeavour and Essential Energy*, February 2017, p. 21.

6 AER, *Final Decision: Tariff structure statements: Ausgrid, Endeavour and Essential Energy*, February 2017, p. 21.

7 Endeavour Energy, Tariff Structure Statement 1 July 2019 - 30 June 2024, April 2018, pp. 18-21; Endeavour Energy, Tariff Structure Explanatory Statement 1 July 2019 - 30 June 2024, April 2018, pp. 44 - 50.

8 Endeavour Energy, Tariff Structure Statement 1 July 2019 - 30 June 2024, April 2018, p. 13.

9 Endeavour Energy, Tariff Structure Statement 1 July 2019 - 30 June 2024, April 2018, pp. 18-21.

10 Endeavour Energy, Tariff Structure Statement 1 July 2019 - 30 June 2024, April 2018, pp. 18-21

18.2 AER draft decision

We commend Endeavour for the significant consultation it has undertaken to help develop its tariff structure statements. Our draft decision is to accept Endeavour's 2019–24 tariff structure statement in respect of:

- structure of the demand tariffs for residential and small business customers
- approach to calculating the long run marginal costs
- prescribed large business tariff assignment to cost reflective tariffs
- narrowing the peak charging windows.

We consider that these contribute to compliance with the distribution pricing principles and to the achievement of the network pricing objective.[11]

We endorse how Endeavour has set out its tariff structure statement in two documents. We recommend other regulated businesses adopt Endeavour's two-document tariff structure statement format.

We do not approve all elements of Endeavour Energy's proposal

However, our draft decision is also to not accept the following elements of Endeavour's tariff structure statement, and therefore to not approve the tariff structure statement as a whole. 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:[12]

- the description of how Endeavour will base tariffs on the long run marginal costs and its approach to recovering residual costs
- the tariff assignment policy that will not reassign all customers that receive smart meters to cost reflective network tariffs, assigns customers to a transitional tariff by default and allows customers to opt-out to a non-cost reflective flat network tariff
- cost reflectivity of its tariff structure for large businesses on the low voltage, high voltage and sub-transmission networks
- the removal of optional time of use energy tariffs for residential and small business customers.

[11] NER, cl. 6.18.5(d).

[12] NER, cl. 6.18.5(d).

18.3 AER's assessment approach

This section outlines our approach to assessing tariff structure statement.

There are two sets of requirements for tariff structure statements. First, the NER set out elements that an approved tariff structure statement must contain.[13] Second, a tariff structure statement must also comply with the distribution pricing principles.[14]

What must a tariff structure statement contain?

The NER require a tariff structure statement to include:[15]

- 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.[16] 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.[17] 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[18]
- 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[19]

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

- 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[20]
- distributors must consider the impact on customers of tariff changes and may depart from efficient tariffs, if reasonably necessary having regard to:[21]
  - 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[22]
- tariffs must otherwise comply with the NER and all applicable regulatory requirements.[23]

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:*[24]

> *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.*[25]

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.

[20] NER, cl. 6.18.5(g).
[21] NER, cl.6.18.5(h).
[22] NER, cl. 6.18.5(i).
[23] NER, cl. 6.18.5(j); this requirement includes jurisdictional requirements.
[24] NER, cl. 6.18.5(d)
[25] NER, cl. 6.18.5(a)

Figure 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. The tariff structure statement is accompanied by an indicative pricing schedule that sets out expected price levels over the five year regulatory proposal. This document is submitted to the AER for assessment against the distribution pricing principles in conjunction with the distributor's five year regulatory proposal. The AER then approves the tariff structure statement if it meets the distribution pricing principles and other National Electricity Rules requirements.
Second stage	Distributors develop and submit their annual pricing proposals to the AER. The annual pricing proposals essentially apply pricing levels to each of the tariff structures outlined in the approved tariff structure statement. Distributor's proposed pricing levels must be consistent with the indicative pricing schedule, or the distributor must explain why its proposed price levels differ from the indicative pricing schedule. The AER's assessment of the distributor's pricing proposal is a compliance check against the approved tariff structure statement and the control mechanism specified in the AER's regulatory determination.

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

- requirements that would facilitate meaningful consultation and dialogue between distributors, the AER, retailers and consumers
- increased certainty with respect to changes in network tariff structures and more timely notification of approved changes to network tariff pricing levels
- more opportunity for retailers and consumers to inform and educate themselves about how network tariffs will affect them and how they should respond to the pricing signals
- the AER to have appropriate timeframes and capacity to assess the compliance of the distributors proposed network tariffs against the distribution pricing principles and other requirements
- Distributors to maintain ownership of network tariffs and to adjust the pricing levels of their tariffs to recover allowed revenues.[26]

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

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 and be consistent with the indicative pricing schedule[27] when setting prices annually for direct control services.[28]

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.[29] 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.[30]

18.4 Reasons for draft decision

Our draft decision is to not approve Endeavour's proposed tariff structure statement, as we are not satisfied that it complies with the distribution pricing principles. While we are satisfied parts of tariff structure statement contribute to compliance with the distribution pricing principles and to the achievement of the network pricing objective, we consider that some elements of the tariff structure statement require amendment and further detail.

The section below sets out:

- the reasoning for our decision for each customer group
- our assessment of Endeavour Energy's estimate of long run marginal cost
- the completeness and compliance of the tariff structure statement with the requirements in the NER.

We have included a series of appendices which support these reasons.

[27] Distributors must explain any material departure from the indicative pricing schedule in their annual pricing proposals. NER 6.18.2(b)(7A).

[28] NER, cl. 6.18.1A(c).

[29] NER, cl. 6.18.1B.

[30] NER, cl. 6.18.1B(d).

18.4.1 Residential and small business tariffs

We are satisfied that the following aspects of Endeavour's proposal for residential and small business customer contributes to compliance with the distribution pricing principles:[31]

- the determination of charging windows that reflect times of network congestion
- the flat tariff for customers with accumulation meters
- the structure of the demand tariffs.

Despite this, we are not satisfied that Endeavour's tariff assignment policy for residential and small business customers, which allows retailers to 'opt-out' of cost reflective network tariffs or network tariffs that will transition to cost reflective network tariffs, will provide an adequate pace of reform.

To comply with the distribution pricing principles and other applicable requirements of the NER we also require Endeavour to consider:

- offering a seasonal time of use energy tariff
- assigning customers to a cost reflective network tariff by default
- not allowing customers to 'opt-out' of a cost reflective tariff to a flat tariff.

18.4.1.1 Tariff design, levels and charging windows

Customers should face cost reflective tariffs

Endeavour proposed default assignment to a transitional tariff for residential and small business customers.[32] Transitional tariffs are structured like cost reflective tariffs, but the price levels of the component charges do not reflect long-run marginal cost.

We do not approve Endeavour's proposed default assignment to its proposed transitional tariff. We recommend that Endeavour's default assignment should be to a cost reflective tariff. We consider that this is necessary to make sufficient progress towards the network pricing objective.[33]

The proposed transitional tariff is a seasonal monthly demand tariff, however because the usage charge is relatively high and demand charge relatively low, it is only marginally more cost reflective than a flat tariff.[34]

Depending on how transitional tariffs are designed and their relative price levels will impact the degree to which they represent a move towards cost reflectivity. We seek stakeholder

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31 NER, cl. 6.18.5(d).

32 Endeavour Energy, Tariff Structure Statement 1 July 2019 - 30 June 2024, April 2018, p. 13.

33 NER, cl. 6.18.5(d).

34 Endeavour Energy, Tariff Structure Statement 1 July 2019 - 30 June 2024, April 2018, pp. 39-43.

feedback on the customer impacts of having default assignment to a cost reflective tariff but offering the transitional tariff on an optional basis, as a means for customers to mitigate bill impacts in the immediate term.

We have analysed the cost reflectivity of different tariff structures (see Appendix B for more details). Our indicative analysis found:

- Endeavour's proposed seasonal monthly demand tariff with a flat energy charge is cost reflective. Therefore, we approve Endeavour's proposal to apply this tariff structure for residential and small business customers. We consider that a seasonal monthly demand tariff, with flat energy charges is suitable for default assignment.
- Seasonal time of use energy tariffs are cost reflective. On this basis, we consider that Endeavour should offer customers a seasonal time of use energy tariff, as it is cost reflective and customers typically understand time of use energy tariffs. We note Endeavour currently offers customers a time of use tariff. We consider a seasonal time of use tariff is suitable for default assignment.

We consider that both seasonal time of use tariffs and seasonal monthly demand tariffs balance the achievement of greater cost reflectivity with the needs of customers:

- Both tariff structures concentrate revenue recovery within smaller charging windows, this makes it easier for customers to impact their network charges through changes to their usage.[35]
- Endeavour currently offers a time of use tariff and neighbouring Ausgrid has 330,000 residential customers on its time of use tariff, with this level of penetration we expect that customers understand the time of use tariff structure.[36]
- Seasonal monthly demand tariffs with flat energy charges are similar to flat tariffs with the addition of a monthly maximum demand charge, we consider that customers will understand these tariffs given their limited complexity.[37] We note that customer advocates, such as the Public Interest Advocacy Centre, have championed this form of tariff indicating their confidence that customers will understand the tariff structure.[38]

Therefore, Endeavour's revised tariff structure statement should assign all residential and small business customers, by default to its time of use energy tariff, or a seasonal monthly demand tariff with flat energy charges.[39] To comply with the network pricing principles

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

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

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

[38] Public Interest Advocacy Centre, *Submission in response to the NSW DNSPs 2019-24 regulatory proposals and AER issues paper*, 8 August 2018, pp. 29-30.

[39] This will increase cost reflectivity. NER, cl 6.18.5(a).

customer impact principle we consider Endeavour must offer the other tariff as an 'opt-out' tariff to all customers.[40]

We contemplate that Endeavour's transitional demand tariff would likely comply with the distribution pricing principles, if included as an optional tariff in its revised tariff structure statement. Transitional tariffs reduce the immediate impact of demand tariffs to customers by slowly transitioning charges towards cost reflective levels.[41] Transitional tariffs are valuable to customers that experience increases to network charges and need time to adjust their demand characteristics in response.

Customers with accumulation meters will face flat tariffs

Endeavour proposed to continue to charge customers who have accumulation meters, flat energy tariffs. We consider flat energy tariffs are the most suitable tariffs for customers that do not have interval metering, because:

- they reflect that an individual's consumption of additional units of electricity do not impose more costs per unit on the network[42]
- they are easy for consumers to understand.[43]

Endeavour should not allow customers to opt-out to flat tariffs if they have a smart or interval meter. This will grandfather flat tariffs, allowing customers currently facing a flat tariff to stay on it until they receive a new meter or change their connection characteristics.

Endeavour Energy's proposed charging windows are appropriate

Time of use energy tariffs charge customers different rates per unit of electricity at different times, and demand tariffs only charge customers based on their demand at certain times. These times are called charging windows. Endeavour proposes peak demand charges based on maximum 30-minute demand between 4pm and 8pm on weekdays, year-round.[44] We approve this.

Endeavour makes its demand tariffs seasonal, by applying different demand tariffs in the high season (November to March, inclusive) than in the rest of the year. Endeavour's current time of use energy tariffs and large business demand tariffs have a peak charging window of 1pm to 8pm.

Figure 18-2 shows that most peak demand events, at the substation zone level, occur between the hours of 4pm and 8pm. Importantly, this analysis finds that only two per cent of

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40 NER, cl 6.18.5(h)(3) and NER, cl 6.18.5(i).

41 NER, cl. 6.18.5(h).

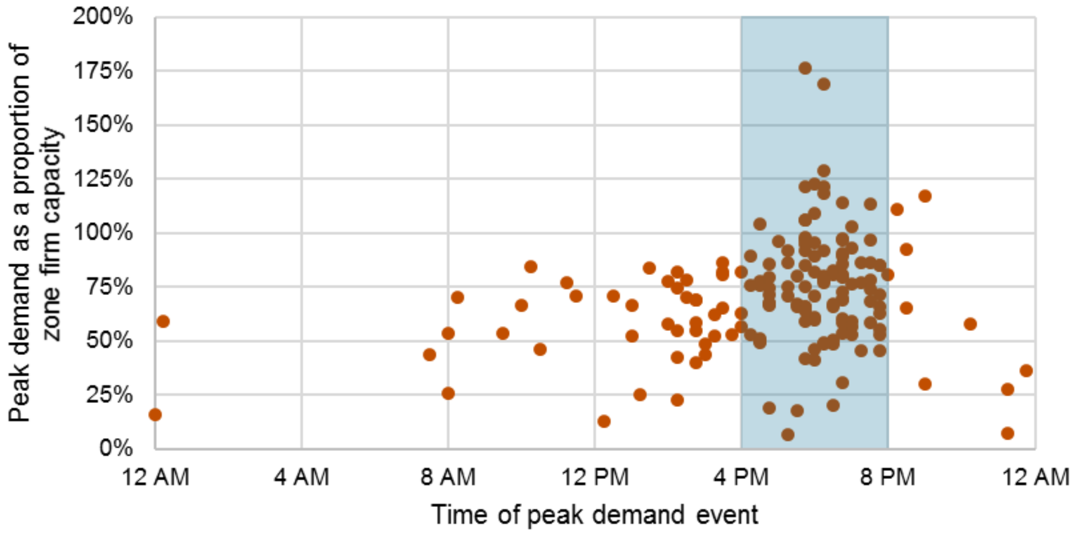
42 Therefore, a flat tariff is more closely based on long-run marginal costs (NER 6.18.5(f)) as the long-run marginal cost per unit of electricity is the same regardless of the quantity purchased by a single customer.

43 NER, cl. 6.18.5(i).

44 Endeavour Energy, Tariff Structure Statement 1 July 2019 - 30 June 2024, April 2018, pp, 18-21.

substation zones, with less than 20 per cent spare capacity at the substation zone peak event, peaked outside of the 4pm to 8pm peak window from November 2016 to March 2018.

Figure 18-2 Endeavour Energy substation zone peak demand events



Source: Endeavour Energy response to AER Information Request #024.

Variation from the indicative pricing structure should be predictable

We consider that to provide certainty that improves the ability of customers to respond to tariffs[45] and understand their tariffs,[46] distributors tariff structure statements should ensure that they do not deviate from the indicative pricing schedules, except due to:

- annual variation in the revenue cap compared to the revenue used to model the indicative pricing schedule
- variation to the long-run marginal cost estimate.

We consider that Endeavour's proposed approach to setting prices does not create sufficient certainty for customers. In this section, we require clarity on how:

- Endeavour will base each of its tariffs on long-run marginal cost
- Endeavour will recover residual costs that vary due to revenue and long-run marginal cost.

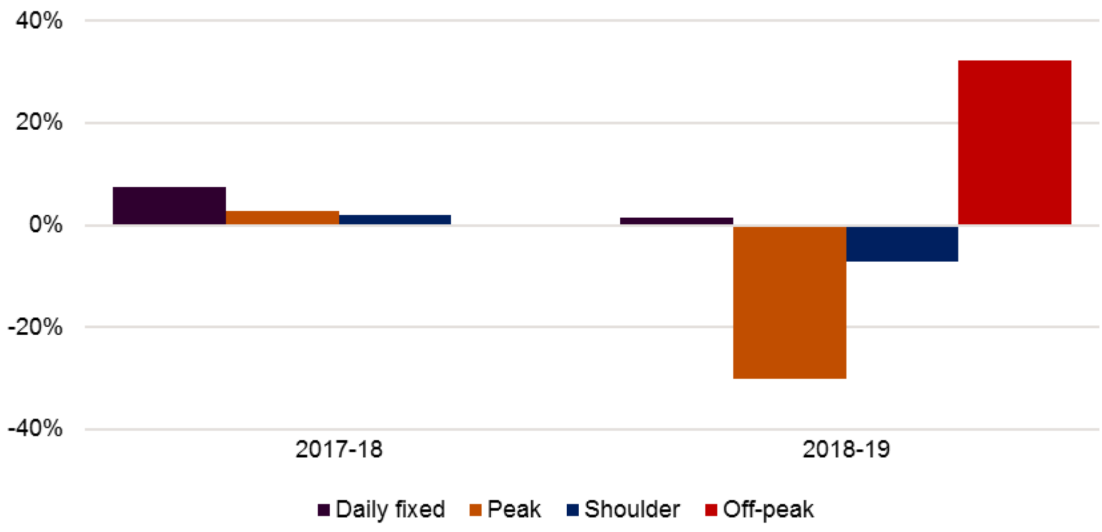
We note that in the past Endeavour has made changes through the annual pricing process that are not explained by variation to the annual revenue requirement and long-run marginal

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

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

cost estimates. Figure 18-3 shows variation from Endeavour's tariff structure statement compared to its current indicative price schedule for its residential time of use tariff.

Figure 18-3 Endeavour Energy variation from indicative pricing schedule



Source: Endeavour Energy, 2018-19 Pricing proposal, March 2018, p. 31.

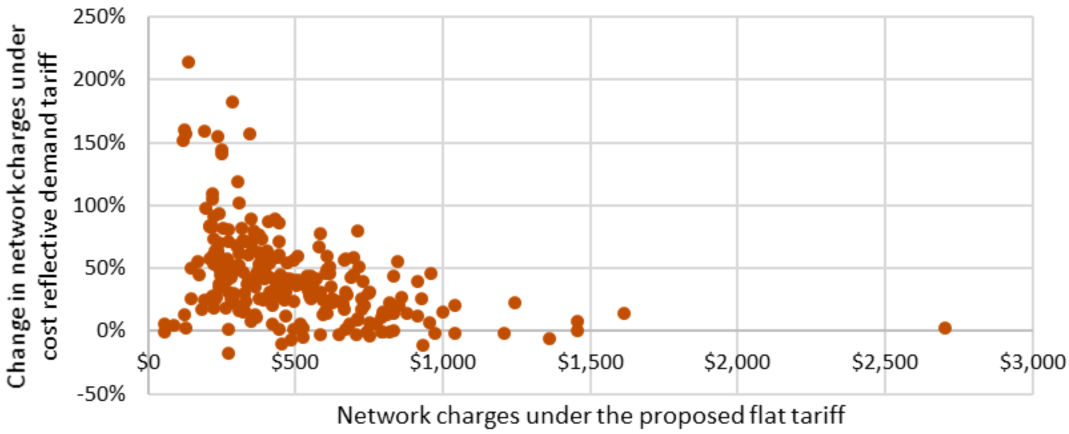
We consider that Endeavour's revised tariff structure statement should help customers understand the longer-term trajectory of their tariffs so they can make long-term behavioural changes and invest with certainty in demand management or other services.[47]

The average customer should not be worse off under tariff reform

We recommend that Endeavour reconsider the price level of its cost reflective demand tariff. We analysed the customer impacts to customers moving to different tariffs, based on historical interval meter data provided by Endeavour. Figure 18-4 shows the impact on individual customers of moving from the proposed flat tariff to the proposed cost reflective demand tariff in 2023-24.

47 NER, cl. 6.18.5(h)(3).

Figure 18-4 Endeavour Energy variation from indicative pricing schedule



Source: AER analysis of Endeavour Energy, Tariff Structure Statement 1 July 2019 - 30 June 2024, April 2018, and Endeavour Energy response to AER Information Request #026.

This analysis finds that 93 per cent of customers will face higher network charges if they move to the cost reflective demand tariff. We consider that distributors should set cost reflective tariffs at the same average tariff level or lower than the legacy anytime tariffs.[48]

We seek clarity on why small business customers pay more

Each of the NSW distributors' indicative pricing schedules, including Endeavour's, include high tariff levels for small business when compared to residential customers.[49] We are seeking further information from Endeavour about why it proposes higher tariff levels for small business customers. For Endeavour, both the fixed charges and the usage charges for small business customers are higher than the equivalent charges for residential customers.

18.4.1.2 Tariff assignment policy

Endeavour Energy should remove opt-out to anytime tariffs

Endeavour has proposed to allow all assigned and reassigned customers to opt-out to flat tariffs,[50] see Figure 18-5 below. We consider that Endeavour'sproposal to allow opt-out to flat tariffs puts in jeopardy any progress towards the achievement in the network pricing objective over the 5-year period.[51]

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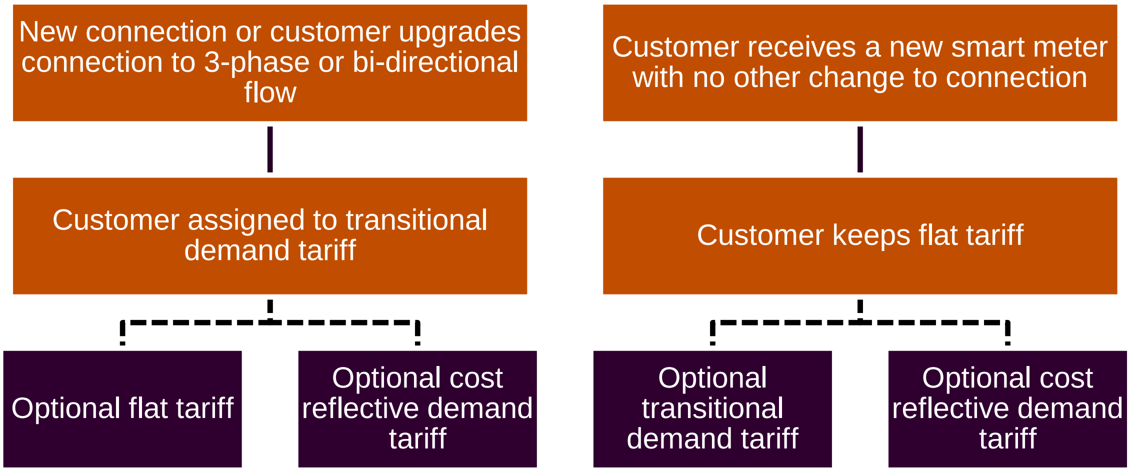
48 This helps achieve progress towards the network pricing objective, as it manages customer impacts of this transition. NER, cl. 6.18.5(d).

49 Endeavour Energy, Tariff Structure Statement 1 July 2019 - 30 June 2024, April 2018, pp. 39-43.

50 Endeavour Energy, Tariff Structure Statement 1 July 2019 - 30 June 2024, April 2018, p. 13.

51 NER, cl. 6.18.5(d).

Figure 18-5 Endeavour Energy's proposed residential assignment policy



We note that Endeavour does not propose to reassign any existing customers that keep their existing connection without upgrading to 3-phase or bi-directional flow.[52] This means that most customers will see no change, including customers that already have interval meters and customers that keep their accumulation meters.

We encourage Endeavour to revise its tariff structure statement to replace its optional flat tariff with an optional time of use energy tariff. We consider that this approach contributes to the achievement of the network pricing objective without breaching the customer impact principles.

To determine the historic and forecast effectiveness of Endeavour's current opt-in and its proposed opt-out tariff assignment policies we requested Endeavour provide projections on the penetration of cost reflective tariffs and interval metering. Figure 18-6 below shows that Endeavour's proposed TSS, in our view, does not sufficiently contribute to the achievement of the network pricing objective, and therefore does not comply with the distribution pricing principles.[53]

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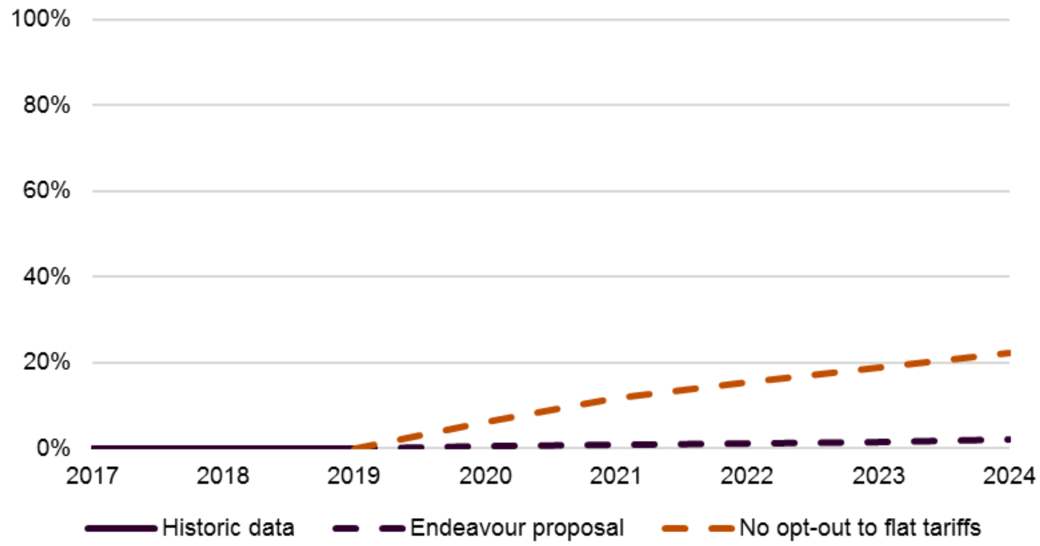
[52] Endeavour Energy, Tariff Structure Statement 1 July 2019 - 30 June 2024, April 2018, p. 13.

[53] NER, cl. 6.18.5(d).

Figure 18-6 Proportion of residential customers on cost reflective tariffs



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

Figure 18-6 demonstrates that Endeavour expects projects very little uptake of cost reflective tariffs (including its transitional tariff) over the 2019–24 regulatory control period. We consider that this is insufficient progress towards cost reflective network tariffs. By contrast, requiring Endeavour's opt-out alternative to also be a cost reflective tariff will lead to a significant increase in the proportion of customers facing cost reflective network tariffs.

We seek changes to Endeavour Energy's trigger for tariff reassignment

Endeavour proposed in its tariff structure statement to immediately:

- Assign new connections to a transitional demand tariff
- Reassign connections that upgrade their connection to 3-phase or bi-directional flow.[54]

We support these elements of Endeavour's tariff assignment policy. However, we recommend that Endeavour transfer customers that receive a new interval meter to cost reflective tariffs. We consider that distributors should provide these customers, who receive a new meter without changing their location or connection, with a 12-month data-sampling period. 12-months of interval meter data should help customers:

- understand their network charges and how they can change their behaviour to reduce network charges[55]

[54] Endeavour Energy, Tariff Structure Statement 1 July 2019 - 30 June 2024, April 2018, p. 13.

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

- make a more informed selection of retail tariffs.[56]

We are open to approving extending this 12-month data-sampling period to all assigned and reassigned customers, if supported by distributors and stakeholders. We consider that all customers could benefit from 12 months of data. We consider that distributors should allow customers to opt-out of the sampling period and immediately face cost reflective tariffs.

We encourage distributors, retailers, governments and consumer groups to offer support to customers in understanding how to minimise their network charges and select appropriate retail tariffs.

18.4.2 Medium and large business tariffs

We are satisfied that the following aspects of Endeavour's proposal for medium and large business customers contributes to the compliance with the distribution pricing principles and to the achievement of the network pricing objective:

- The determination of charging windows that reflect times of network congestion
- Prescribed tariff assignment to cost reflective tariffs.

We require Endeavour to make greater progress towards the network pricing objective by:

- Maintaining the cost reflectivity of its existing tariff structures for medium and large business customers
- Provide greater transparency on how it calculates individual business tariffs.

18.4.2.1 Tariff design, levels and charging windows

The below discussion focuses on the issues we found that are unique to Endeavour's proposal for medium and large businesses. Our findings and discussion above on Endeavour's charging windows and approach to setting prices for residential and small business customers is also applicable to medium and large business customers.

Endeavour Energy's proposal reduces cost reflectivity

Endeavour proposed that every medium and large business would face a seasonal demand tariff with a flat energy charge.[57] Under the current tariff structure statement, medium and large business customers face a seasonal demand tariff with a time of use energy charge.

Our analysis of residential interval meter data of Endeavour's customers suggests that this constitutes a reduction in the cost reflectivity of their tariffs, and therefore is at odds with the

[56] NER, cl. 6.18.5(h).

[57] Endeavour Energy, Tariff Structure Statement 1 July 2019 - 30 June 2024, April 2018, pp. 13-14.

achievement of the network pricing objective.[58] We note that our analysis only looked at residential customers of Endeavour and low voltage business customers of Ausgrid and Essential Energy. If Endeavour has evidence that suggests a seasonal demand tariff with flat energy charge is as cost reflective as the current tariff structure we will reconsider our position.

We seek clarity on individually calculated tariffs

Endeavour's tariff structure statement includes individually calculated tariffs as part of its suite of network tariffs for very large high-voltage and sub-transmission customers that:

- Have consumed at least 100 GWh of electricity in the preceding 36 months,
- Have consumed at least 40 GWh of electricity in each of the preceding 2 financial years, or
- Have monthly peak demand of at least 10 MVA for 24 of the last 36 months.[59]

Given the complexity of their connection arrangements and their greater ability to bypass the distribution network (e.g. by connecting directly to TransGrid), 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.[60] However, at present the tariff structure statement does not outline how Endeavour will calculate these tariffs.

We require Endeavour to outline its approach to setting individually calculated tariffs, in particular outlining how they will diverge from the standard high voltage and sub-transmission tariffs. This will also mean Endeavour will need to provide the AER how it calculated for each individually calculated tariff as part of the annual pricing process, albeit on a commercial in confidence basis.

18.4.2.2 Tariff assignment policy

We support all aspects of Endeavour's proposed tariff assignment policy for medium and large business customers. This includes:

- prescribed cost reflective tariff assignment for all customers with interval metering
- transitional arrangements for low voltage customers with accumulation metering.[61]

Endeavour's proposed tariff assignment policy will mean that all customers capable of facing a cost reflective tariff will do so, ensuring progress towards the network pricing objective.[62] Additionally, we consider that medium and large business customers due to the scale of their

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58 NER, cl. 6.18.5(d).

59 Endeavour Energy, Tariff Structure Statement 1 July 2019 - 30 June 2024, April 2018, p. 14.

60 NER, cl. 6.18.5(a).

61 Endeavour Energy, Tariff Structure Statement 1 July 2019 - 30 June 2024, April 2018, pp. 13-14.

62 NER, cl 6.18.5(d).

electricity expenditure are able to understand their tariffs[63] and manage their usage to mitigate the impacts of changes on their retail bills.[64]

18.4.3 Long run marginal cost (LRMC) estimate

An important feature of this draft decision is the concept of long run marginal cost. Long run marginal cost 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.[65] 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.[66] 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 long run marginal costs 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 long run marginal cost.[67]

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

Below we describe Endeavour's approach to estimating long run marginal costs (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 Endeavour Energy estimation method

Endeavour implemented the Average Incremental Cost approach to calculate its long run marginal cost estimates using a forecast horizon of ten years.[68]

It stated electricity distributors have not widely adopted an alternative method, known as the Turvey approach, because it is administratively burdensome.[69]

63 NER, cl 6.18.5(i).

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

65 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.

66 NER, cl. 6.18.5(f).

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

68 Endeavour Energy, *TSS 0.01 Tariff Structure Statement*, April 2018, p. 25; Endeavour Energy, *TSS 0.04 Tariff Structure Explanatory Statement*, April 2018, p. 8.

69 Endeavour Energy, *TSS 0.04 Tariff Structure Explanatory Statement*, April 2018, p. 79.

Endeavour remarked the incorporation of replacement capex (repex) into long run marginal cost calculations should include expenditure that is related to demand increments or decrements.[70] Endeavour considered this was an improvement to the Average Incremental Cost approach. It measured replacement capex under two separate scenarios:[71]

- in parts of the network where over the forecast ten year period demand is expected to be growing
- in areas where demand is stable or declining in the forecast period

In the first scenario, Endeavour identified zone substations at which it forecast growing demand over the next ten years. It estimated LRMC by taking the ratio of all site-specific augmentation capex (augex) and all program augex to the sum of forecast demand at those zone substations.[72] This is conceptually consistent with Endeavour's approach to estimating long run marginal cost in its first tariff structure statement.

Endeavour did not include repex in growth areas because all such expenditure is forecast to be like-for-like. That is, there is no requirement for replacing assets with higher capacity assets.[73] In future tariff structure statements, Endeavour said it would include such demand-driven repex in long run marginal cost estimates (as long as it is not captured in the augex forecast because doing so would double count such estimates).[74]

Table 18-1 includes Endeavour's long run marginal cost estimates for areas of growing demand.

Table 18-1 Endeavour Energy LRMC estimates where demand is growing

Service	LRMC estimate ($/kW pa)
Low voltage	133
High voltage	12
Sub-transmission	9

Source: Endeavour Energy, *TSS 0.04 Tariff Structure Explanatory Statement*, April 2018, p. 83.

70 Endeavour Energy, *TSS 0.04 Tariff Structure Explanatory Statement*, April 2018, pp. 80–81.

71 Endeavour Energy, *TSS 0.04 Tariff Structure Explanatory Statement*, April 2018, pp. 81–82.

72 Endeavour Energy, *TSS 0.04 Tariff Structure Explanatory Statement*, April 2018, p. 82.

73 There is an exception where Endeavour proposed to replace one of the 5MVA transformers at the Gerringong zone substation with an existing spare 10MVA transformer. Endeavour noted this is a least cost replacement, rather than a demand-driven one.

74 In this circumstance, Endeavour noted the cost of the larger asset would be split into a repex component based on the cost of a like-for-like asset replacement, with the remainder of the cost being allocated to augex. See Endeavour Energy, *TSS 0.04 Tariff Structure Explanatory Statement*, April 2018, p. 81–82.

In areas of decreasing demand, Endeavour submitted there is a non-linear relationship between changes in demand and changes in repex. The cost savings from downsizing assets are typically low because the cost difference between assets of different capacity are low.[75] In addition, installation costs comprise a significant proportion of total costs.[76] Endeavour further pointed out that a distributor must assess the downsizing of assets against the risk of future demand growth. This might require augmentation capex that outweighs the savings from downsizing assets.[77]

Endeavour used the Marayong substation replacement project to derive the relationship between changes in demand and repex savings. In conjunction with a non-network solution and load transfer, Endeavour proposed to lower the capacity of the substation because demand is forecast to be stable. The non-network solution would enable reduction of demand by 34 per cent while lowering the substation's capacity reduces repex by 7.9 per cent. From this, Endeavour derived a 5:1 ratio (approximately) between the fall in demand and repex savings.[78]

Endeavour used this ratio as an adjustment factor in a modified average incremental cost approach to derive long run marginal cost estimates for areas of falling demand:[79]

$$\begin{aligned}&Long\ Run\ Marginal\ Cost\\ &= \frac{NPV(total\ capital\ and\ operating\ replacement\ costs\ for\ relevant\ substations)}{NPV(total\ demand\ at\ the\ relevant\ substations)} \times \frac{7}{34}\end{aligned}$$

Table 18-2 includes Endeavour's long run marginal cost estimates for areas where demand is stable or falling.

Table 18-2 Endeavour Energy LRMC estimates where demand is stable or falling

Service	LRMC estimate ($/kW pa)
Low voltage	15
High voltage	1
Sub-transmission	1

Source: Endeavour Energy, *Response to information request 023*, 25 July 2018, p. 2.

Note: Endeavour clarified the column headings in table 18 of its tariff structure explanatory statement were entered incorrectly.

75 For example, Endeavour stated the difference between a 25MVA and a 35 MVA transformer is approximately $300,000.

76 Endeavour Energy, *TSS 0.04 Tariff Structure Explanatory Statement*, April 2018, p. 84.

77 Endeavour Energy, *TSS 0.04 Tariff Structure Explanatory Statement*, April 2018, p. 84.

78 Endeavour Energy, *TSS 0.04 Tariff Structure Explanatory Statement*, April 2018, p. 86.

79 Endeavour Energy, *TSS 0.04 Tariff Structure Explanatory Statement*, April 2018, p. 87.

Endeavour considered the long run marginal cost estimates in Table 18-1 are the appropriate basis for developing tariff levels because:[80]

- the forecast demand increase in areas of growing demand are much larger than the forecast demand decrease in areas of falling demand.
- the long run marginal cost estimates in areas of growing demand are much larger than the corresponding estimates in areas of stable or falling demand (see Table 18-1 and Table 18-2, respectively).

Endeavour considered departing from the estimates in Table 18-1 would result in greater cost consequences due to inefficient use of the network compared to departing from the estimates in Table 18-2.

18.4.3.2 Assessment of LRMC approach

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

As we discuss below, however, we encourage Endeavour to improve the implementation of its approach for including repex in the long run marginal cost estimates in the revised proposal.

Incorporation of repex into LRMC

We consider Endeavour's proposed approach to incorporating repex into its long run marginal cost estimates contributes to compliance with the distribution pricing principles and to the achievement of the network pricing objective. However, we encourage Endeavour to improve how it implemented this approach in the revised proposal, and in future years.

As we described in section 18.4.3.1, Endeavour's approach treats avoided repex in substations with stable or growing demand as marginal costs. We regard that as consistent with the definition of marginal cost (see our assessment framework appendix C).

'Marginal costs' are often discussed in terms of 'incremental' or 'positive' changes in demand. Indeed, the NER define long run marginal cost as 'the cost of an incremental change in demand' for network services.[81]

However, marginal costs also apply to 'decrements' or 'negative' changes in demand. So, marginal costs signal the additional future costs of increasing use of the distribution network, as well as future avoided costs of decreasing use of the distribution network.[82]

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[80] Endeavour Energy, *TSS 0.04 Tariff Structure Explanatory Statement*, April 2018, p. 88.

[81] NER, chapter 10 Glossary.

If the benefits customers derive from their use of the network exceeds the long run marginal cost, they will increase their use, which would signal to the distributor to invest in additional capacity.

Conversely, if the benefits customers derive from their use of the network is less than the long run marginal cost, they will decrease their use. This would signal to the distributor to lower the capacity of the network.

As noted earlier, we encourage Endeavour to improve how it implemented this approach in the revised proposal. In particular, Endeavour should use more than a single sample to derive the relationship between changes in demand and repex.

As we discussed in section 18.4.3.1, Endeavour used the Marayong substation replacement project to derive the relationship between changes in demand and repex savings. Endeavour then used this relationship in calculating the long run marginal cost estimates for substations with stable or falling demand in Table 18-2.

We consider it is more appropriate to use more than a single sample to, in this case, establish the relationship between changes in demand and repex savings. Other replacement projects may point to different relationships between changes in demand and repex savings. These in turn could indicate different long run marginal cost estimates for areas where demand is stable or falling.

Further, we identified issues with Endeavour's proposal for the Marayong substation replacement project. Among other things, we do not consider it complies with the AER guidelines on the regulatory investment test for distribution (see attachment 6 of this draft decision).

Using a number of different projects—including historical projects, if appropriate—would provide Endeavour several values for the relationship between demand and repex savings. This would provide a range of values in which such a relationship could fall, which in turn would provide greater confidence regarding any point estimates.

Estimation method

We consider Endeavour's method for deriving its long run marginal cost estimates contributes to compliance with the distribution pricing principles and to the achievement of the network pricing objective. We also commend Endeavour for innovating its implementation of the Average Incremental Cost approach.

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

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[82] Technically, marginal cost represents the tangent to a firm's cost function at any given level of output. This is consistent with the textbook definition of marginal cost, which is 'the change in cost as output changes.' See Jeffrey R Church and Roger Ware, *Industrial Organization: A Strategic Approach*, 2000, p. 20.

As we discuss in appendix C, long run marginal costs largely depend on the level of congestion in different locations within a network (as well as temporal factors). However, postage stamp pricing applies across Endeavour's network and will continue to apply in the 2019–24 regulatory control period. Due to postage stamp pricing, Endeavour submitted customers will necessarily receive price signals that differ from the long run marginal costs appropriate to them.[83] This limits the extent to which end customers can receive and respond to long run marginal cost signals.

In this context, we consider the limitations of the Average Incremental Cost approach—the perception that the estimates they derive are not the best representations of long run marginal costs—are outweighed by its relatively low cost of implementation.[84]

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

As we described in section 18.4.3.1, Endeavour used the Average Incremental Cost approach to produce two sets of long run marginal cost estimates: one for areas of stable or decreasing demand, and another for areas of increasing demand. We commend this innovative approach.

We consider Endeavour’s method is a significant philosophical constructive step in the tariff reform process. This is because it has regard to the location associated with the long run marginal cost estimates as envisioned in the NER, albeit at an aggregated level.[85] In the first round of tariff structure statements, distributors did not include locational considerations in their long run marginal cost estimation methods. Rather, they applied the Average Incremental Cost purely at the network wide level.

Forecast horizon

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

Endeavour used a forecast horizon of 10 years to derive its long run marginal cost estimates 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).

18.4.4 Statement structure and completeness

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

- the tariff classes into which its customers will be grouped

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83 Endeavour Energy, *TSS 0.04 Tariff Structure Explanatory Statement*, April 2018, p. 88.

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

85 NER, 6.18.5(f)(3).

- the policies and procedures Endeavour 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 Endeavour will take in setting each tariff in each annual pricing proposal during the regulatory control period.[86]

Endeavour 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.[87]

Endeavour's proposed tariff structure statement largely incorporates each of the elements required under the NER.

We do however consider that Endeavour's proposal was not sufficiently clear regarding:

- Its policies and procedures for reassigning customers on discontinued tariffs (we note that if Endeavour accepts our recommendation to offer a time of use tariff this will no longer be an issue)
- Its approach to setting tariffs in each annual pricing proposal.

We require Endeavour to provide greater clarity on both of these elements in its revised tariff structure statement. This means that:

- if Endeavour continues to propose discontinuing its time of use tariffs for low voltage customers, its assignment policy should outline what Endeavour proposes to do with these customers
- as discussed above, Endeavour's revised tariff structure statement must be clear in how it will vary tariffs from the indicative pricing schedule if there is variation in revenue or changes to long-run marginal cost calculations.

The structure of Endeavour Energy's tariff structure statement is excellent

We consider that the structure of Endeavour's tariff structure statement is best practice. The "two document" approach allows the reader to clearly identify the binding elements of the tariff structure statement and the explanatory content.[88] We endorse the structure of Endeavour's tariff structure statement and encourage all other distributors to adopt a "two document" approach.

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86 NER, cl.6.18.1A(a).

87 NER, cl.6.18.1A(e).

88 NER, cl. 6.18.5(i).

A Retail/network characteristics and relevance to tariff reform for Endeavour Energy

Purpose

Electricity distributors are required to develop their network tariff strategies against a backdrop of a unique set of environmental conditions. Some of these conditions will constrain the reform of network tariffs whilst other conditions will enable more reform to occur than otherwise the case.

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

- Network design and operating conditions – The nature of the electricity network influences the level and spatial variation in 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 distributed energy resources (DER)
- Weather conditions – the seasonal nature of peak demand influences the design of efficient tariffs from a peak charging perspective.
- Retailer pricing behaviour – the extent that retailers pass through network pricing signals influences the nature, timing and distribution of the benefits of tariff reform.
- Government intervention – government policy can influence the nature and pace of tariff reform.

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

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 Endeavour Energy's electricity network

Endeavour's network spans 24,800 square kilometres and is made up of more than 185 major substations, 416,000 power poles and 32,000 smaller substations connected by 47,000 kilometres of underground and overhead cables.

Endeavour's electricity distribution network is shown in Figure 18-7 below.

Figure 18-7 Endeavour Energy Electricity Network

Source: Endeavour Energy 2018

Maximum Demand Growth

Endeavour is predominantly a summer constrained electricity distribution network, where the network is more likely to be constrained on extremely hot summer days. It is under these weather conditions that peak demand is highest due to the simultaneous use of air conditioning and other cooling appliances, such as fans and evaporative coolers. It is also the case that the capacity of the electricity network is reduced by high ambient temperatures.

Endeavour is forecasting significant growth in peak demand in the next regulatory control period. The primary driver of this forecast growth is the expected growth in customer numbers and associated peak demand in new greenfield developments.

Table 18-3 provides a comparison of the Endeavour's forecast of peak demand at the 10% and 50% Probability of Exceedance.

Table 18-3 Forecast of maximum demand – Endeavour Energy

	2020	2021	2022	2023	2024
Maximum demand (MW) 10% POE	4,184	4,274	4,363	4,439	4,512
% change	3.6%	2.2%	2.1%	1.7%	1.6%
Maximum demand (MW) 10% POE	3.949	4,039	4,129	4,205	4,278
% change	3.8%	2.3%	2.2%	1.8%	1.7%

Source: Endeavour Energy 2018

Interestingly, Endeavour's forecast growth in maximum demand over the next five years contrasts with the AEMO medium term forecast where summer peak demand is forecast in most NEM regions to either decline or stabilise over this forecast period (see table below).

Table 18-4 Forecast of maximum demand by NEM region – 50% POE

NEM region	Season	2018	2022	2028
New South Wales	Summer	12,664	12,400	13,172
	Winter	11,725	12,125	12,970
Queensland	Summer	8,625	8,554	8,857
	Winter	7,273	7,605	8,047
Victoria	Summer	8,803	9,221	9,679
	Winter	7,274	7,845	8,323
South Australia	Summer	2,849	2,954	3,004
	Winter	2,301	2,431	2,483

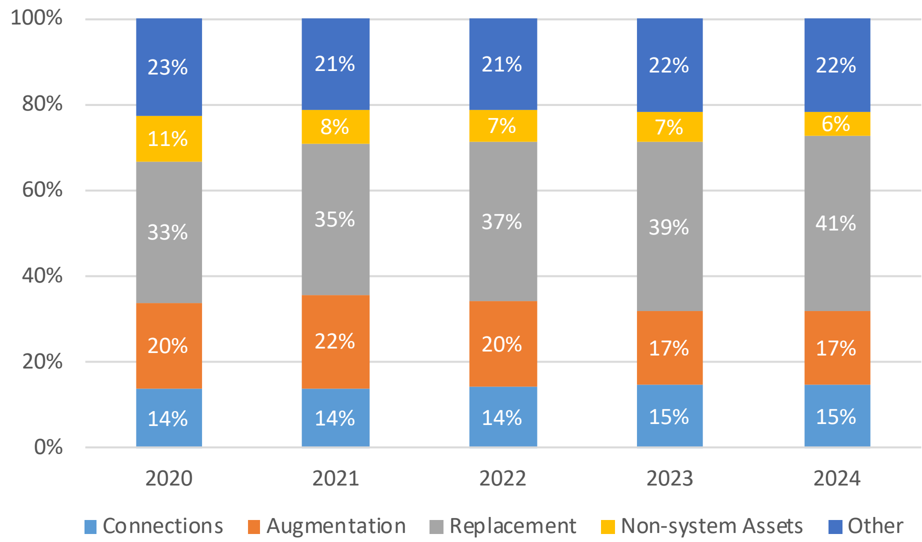
NEM region	Season	2018	2022	2028
Tasmania	Summer	1,337	1,371	1,367
	Winter	1,662	1,707	1,703

Source: AEMO 2018

It should be noted that changes in system-wide peak demand may not necessarily be associated with changes in network costs, given that the need to invest in additional network capacity will also be influenced by the presence of excess capacity and localised variations in maximum peak demand growth.

As with other electricity distributors, replacement-related capital expenditure is a major driver of Endeavour's network costs over the medium term, as highlighted in figure below.

Figure 18-8 Composition of Capital Expenditure - Endeavour Energy



Source: Endeavour Energy 2018

The relatively high importance of replacement capital expenditure in the cost function of most distributors in Australia has implications for the design of cost reflective network tariffs.

Energy Consumption

The table below shows the current AEMO medium term forecast of annual electricity consumption by jurisdiction.[89] [90]

Table 18-5 Forecast electricity consumption by jurisdiction

Year	NSW	QLD	SA	TAS	VIC	NT
2019	66,705	49,422	12,053	10,388	43,303	1,843
2020	66,441	49,363	11,834	10,412	43,184	1,829
2021	66,505	49,334	11,826	10,474	43,468	1,829
2022	66,662	49,622	12,210	10,546	43,995	1,830
2023	66,267	49,912	12,167	10,429	44,145	1,831
2024	66,557	50,202	12,184	10,460	44,552	1,835
2025	67,238	50,407	12,248	10,510	45,294	1,839
2026	68,010	50,388	12,032	10,417	45,264	1,844
2027	68,803	50,304	11,839	10,343	45,298	1,848

Source: AEMO 2018

The key insights from the table above are:

- 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%) over this period reflects the recent growth in coal seam gas production.
- The modest growth in Tasmania (+0.3%) over this period reflects the expected weak growth in both population and gross state product. Continued growth in rooftop Solar PV installations and improvements in energy efficiency are also a factor.

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

90 www.aer.gov.au/system/files/PWC%20-%2004.4P%20AEMO%20PWC%20Maximum%20Demand%2C%20Energy%20Consumption%20and%20Connection%20Forecasts%20-%20Sep%202017.pdf

- Annual electricity consumption is forecast to decline over the medium term in Victoria (-8%), South Australia (-4%), New South Wales (-3%) and Northern Territory (-1%).

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

Another important driver of energy consumption is the adoption of DER. The following table provides a regional comparison of the cumulative installation of Solar Photo voltaic (solar PV) systems by state and territory over the historical ten year period to 2017 period.

Table 18-6 Solar PV system installations by jurisdiction

Year	NSW	QLD	SA	VIC	NT	TAS	ACT
2009	14,008	18,283	8,569	8,429	215	1,452	803
2010	69,988	48,697	16,705	35,676	637	1,889	2,323
2011	80,272	95,303	63,553	60,214	401	2,475	6,860
2012	53,961	130,252	41,851	66,204	513	6,364	1,522
2013	33,998	71,197	29,187	33,332	1,024	7,658	2,411
2014	37,210	57,748	15,166	40,061	1,026	4,207	1,225
2015	33,477	39,507	12,081	31,345	1,197	2,020	1,066
2016	29,495	34,422	12,604	26,724	1,745	2,487	1,001
2017	43,060	46,268	16,151	31,287	1,939	2,389	1,940
2018	37,906	34,733	13,724	23,901	1,310	1,683	1,994

Source: 2018 Clean Energy Regulator

The general growth in solar PV installations over the past decade reflects the falling real price of these systems, the incentives under existing energy-based electricity tariff structures and the influence of government incentives.

The highest number of solar PV system installations have been recorded in Queensland, New South Wales, Victoria and South Australia.

The current penetration of solar PV system in Endeavour's network is around 12 per cent of all customers or around 120,000 customers. Endeavour expects the number of customers with solar PV to grow by around 1-2% per annum during the 2019–24 regulatory control period. The increasing penetration of solar generation has not yet presented any material issues for Endeavour's network.

Energy Consumption per residential customer

The following table highlights the differences in annual electricity consumption for a representative residential customer by jurisdiction.[91] This variation reflects a broad range of influences such as differences in temperature conditions, the mix of appliances and the market penetration of gas for heating and cooking.

Table 18-7 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

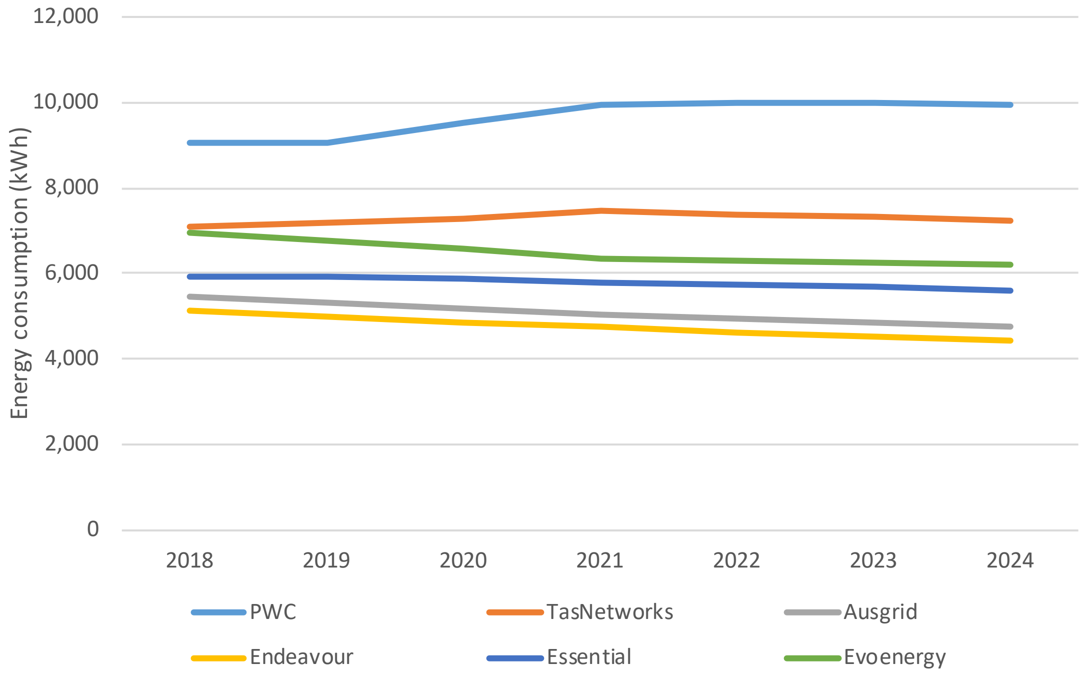
Source: AEMC 2017

The key points from the above table are summarised below:

- 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 part reflecting the higher penetration of gas for heating and cooking.
- Annual residential electricity consumption is similar in South Australia and Queensland.

[91] 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

Figure 18-9 Comparison of residential average consumption per customer by electricity distributor



Source: AER analysis

Interestingly Power and Water Corporation and TasNetworks are the only distributors covered by the analysis shown in the figure above that are forecasting residential energy consumption per customer to increase over the next regulatory control period. Endeavour is forecasting residential energy consumption per customer to remain stable over the next regulatory control period. Essential Energy and Ausgrid are forecasting residential energy consumption per customer to continue to decline over the medium term.

Customer numbers

The table below shows that Endeavour is forecasting relatively strong growth in the number of customers connected to its electricity distribution network over the next regulatory control period.

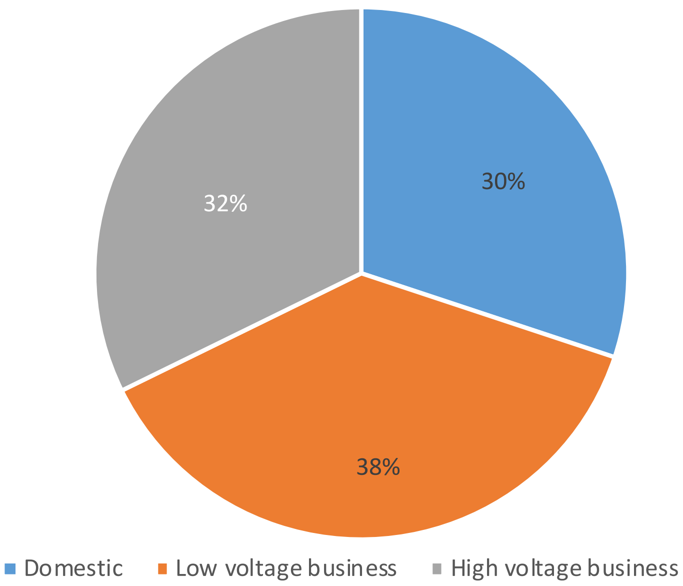
Table 18-8 Annual Customer numbers by type – Endeavour Energy

	2019	2020	2021	2022	2023	2024
Residential	902,360	925,625	946,985	967,238	986,556	1,005,574
LV Business	84,090	84,008	84,881	86,317	87,271	88,484
HV Business	319	319	322	327	330	335
Total	986,768	1,009,952	1,032,188	1,053,882	1,074,158	1,094,393

Source: 2018 Endeavour Energy

While there is a small number of high voltage connected customers connected, the large size of these customers means that they currently account for a material share of Endeavour's total energy consumption per annum, as shown in the figure below.

Figure 18-10 Annual energy consumption by customer type – Endeavour Energy



Source: Endeavour Energy 2018

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 transitioned to cost reflectivity.

Standard control distribution revenue

Endeavour has proposed real increases to their annual revenue requirement in the next regulatory control period for its standard control distribution service (see Table 18-9).

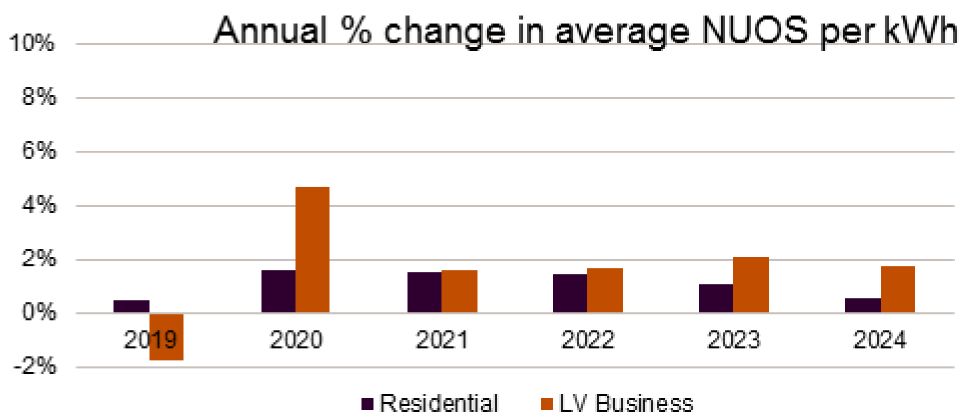
Table 18-9 Endeavour Energy proposed distribution revenue requirement

	2018-19	2019-20	2020-21	2021-22	2022-23	2023-24
Distribution standard control revenue ($m)	843.61	877.69	902.83	926.60	953.52	988.52

Source: Endeavour Energy 2018

On the basis of the proposed distribution revenue requirement and forecast volumes, Endeavour's indicative network use of system prices are expected to on average increase moderately over the next regulatory control period, see figure below.

Figure 18-11 Indicative average network prices - Endeavour Energy



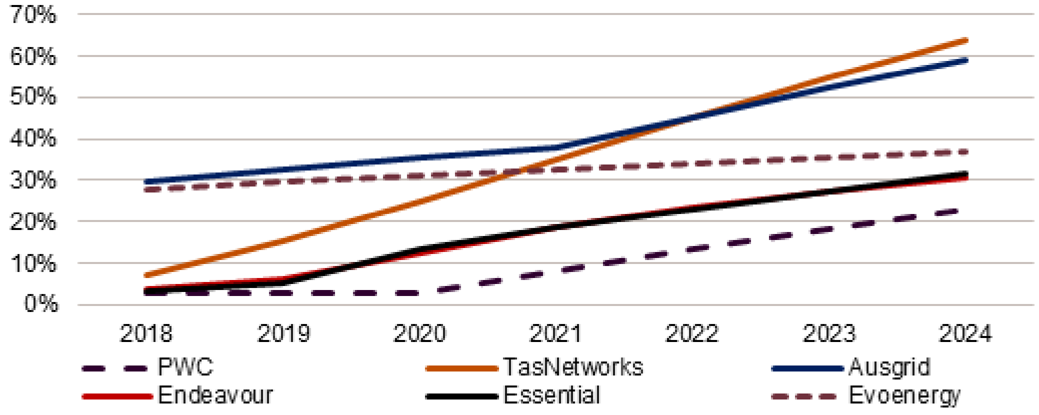
Source: AER analysis

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.

The figure below compares the forecast number of interval metered customers by selected electricity distributor in Australia. 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.[92]

Figure 18-12 Forecast of residential customers with interval metering by electricity distributor



Source: AER analysis

The key points from the figure above are summarised below:

- All distributors covered by the analysis are expected to have a significant penetration of interval metering in the residential sector by the end of the next regulatory control period.
- TasNetworks and Ausgrid are expected to have the highest penetration of interval metering in the residential customer segment with a penetration of 64% and 59%, respectively, by the end of the next regulatory control period.
- Endeavour and Essential Energy are forecast to have a penetration of interval metering in the residential customer segment of 31% and 32%, respectively, by the end of the next regulatory control period.
- Power and Water Corporation is expected to have the lowest penetration of interval metering in the residential sector. Nevertheless, the penetration of Type 4 interval metering is expected to rise to around a quarter of all residential customers by the end of the next regulatory control period.

[92] 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.

Proposed procedures for tariff assignment and reassignment

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

Table 18-10 provides a comparison of the proposed tariff assignment policies for each electricity distributor.

Table 18-10 Comparison of tariff assignment policies for residential and small business customers

DNSP	Description of Proposed tariff assignment procedure
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 seasonal Time of Use energy tariff All customers less than 2 MWh pa to applicable transitional anytime energy tariff with opt-in to 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. Assign existing connections that upgrade to a 3 phase or bi-directional flow to transitional demand tariff with opt-out to flat energy tariff. Existing customers with an interval meter (e.g. due to end of life replacement) to remain on flat energy tariff with opt-in to 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 Existing customers that upgrade to an interval meter (end of life replacement) to remain on flat energy tariff with opt-in to 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 or upgrade to an interval meter due to end of life replacement to remain on applicable flat energy tariff.
Evoenergy	Assign all new connections to demand tariff with the option of opt-in to applicable Time of Use energy tariff. Assign all existing customers that upgrade to an interval meter to a demand tariff with the option of opt-in to Time of Use energy tariff.
Power and Water	Assign all new connections to applicable demand tariff with opt-out allowed to the applicable Time of Use energy tariff. Re-assign existing customers that upgrade to an interval meter to applicable demand tariff with opt-out to Time of Use energy tariff.

Source: 2018 tariff structure statement proposals

The key points from the above table are summarised below:

- TasNetworks' proposed tariff assignment policy based on voluntary opt-in to cost reflective tariffs in the next regulatory control period to FY 2023/24 will result a glacial pace of tariff reform compared to other jurisdictions. With the number of customers on legacy tariffs expected to increase over the medium term under the opt-in approach, it will take well over a decade to complete the transition to cost reflective pricing.
- Evoenergy and Power and Water Corporation propose to adopt a mandated demand tariff assignment policy for all new customers and existing customers that have their basic accumulation meter replaced or upgraded. Evoenergy will allow customers on a demand tariff to voluntarily move to the Time of Use energy tariff.
- Essential Energy proposed to adopt a mandated demand tariff assignment policy for all new customers and existing customers that upgrade to an interval meter for purpose of a connecting a Solar PV system, battery or electric vehicle charger to the electricity network.
- Endeavour proposed to require that all new customers and existing customers that upgrade to a 3 phase connection will be assigned to a transitional demand tariff with the option of voluntarily opt-in to the cost reflective demand tariff. Existing customers with a single phase connection that have their basic accumulation replaced with a Type 4 interval meter will remain on the anytime energy network tariff.
- Ausgrid proposed to adopt a mandated cost reflective tariff assignment policy for all new and existing residential customers with a Type 4 meter installed that consume more than 2 MWh pa. Customers that consume less than 2 MWh pa will be assigned to an anytime energy tariff with the option to voluntarily opt-in to the more cost reflective seasonal Time of Use tariff.

Tariff classes

Distributors are required under clause 6.18.3(b) of the NER to group their customers into tariff classes for the purpose of setting the prices of standard control network 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 electricity distributors, particularly in respect to customers connected at the low voltage level of the electricity network.

Table 18-11 Comparison of current tariff classes by selected electricity distributor

Connection characteristic	Ausgrid	Endeavour Energy	Essential Energy	TasNetworks	Evoenergy	Power and Water
Low voltage (230/400 V)	Low Voltage	• Low Voltage Energy • Low Voltage Demand	• Low Voltage Energy • Low Voltage Demand	• Residential • Small Low Voltage • Large Low Voltage • Uncontrolled Energy • Controlled Energy • Irrigation	• Residential • Commercial Low Voltage	• Less than 750 MWh per annum • More than 750 MWh per annum
High Voltage (11 or 22 kV)	High Voltage	High Voltage	High Voltage	High Voltage	High Voltage	High Voltage
Sub-transmission Voltage (33, 66 or 132 kV)	• Sub-transmission Voltage • Transmission-connected	• Sub-transmission Voltage • Inter-Distributor Transfer (IDT)	Sub-transmission Voltage	Individual Tariff Calculation Class		
Unmetered	Unmetered supply	Unmetered supply	Unmetered supply	Unmetered supply		

Source: AER analysis

Network tariffs

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

- Distribution Use of System (DUOS) component – 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.

Overview of current network tariffs

There are a range of current network tariff structures for residential and small business customers in the NEM, as summarised below:

- It is common for residential and small business customers with accumulation metering to be assigned to a flat network tariff comprising a fixed charge and a uniform energy charge. The only exceptions are Power and Water Corporation and Endeavour, which have adopted inclining block tariff structures currently in place.[93]
- A time of use energy tariff is commonly available for residential and small business customers with interval metering. These tariffs typically comprise a fixed charge and peak, shoulder and off-peak energy charges. The peak times vary considerably across electricity distributors, reflecting in part differences in load profiles.
- Some electricity distributors currently offer demand tariffs to residential and small business customers with interval metering installed, most notably Evoenergy and TasNetworks.

[93] The only exception is Endeavour Energy's current inclining block network tariff for small business customers using less than 160 MWh pa.

Key statistics for Network tariffs

The following tables shows the number of customers and network use of system revenue for the major flat and cost reflective tariffs for residential and small business customers by selected electricity distributors in Australia.

Table 18-12 Current flat energy network tariffs by selected electricity distributor

Electricity Distributor	Network Tariff Name	Network Tariff Code	Customer Numbers in 2018-19	NUOS Revenue ($m) in 2018-19
Ausgrid	Residential non-TOU	EA010	1,115,128	623.1
	Small business non-TOU	EA050	68,250	88.5
Endeavour Energy	Residential non-TOU	N70	683,403	524.0
	General supply non-TOU	N90	81,397	155.1
Essential Energy	LV Residential anytime	BLNN2AU	683,403	541.5
	LV Small Business Anytime	BLNN1AU	81,397	179.5
TasNetworks	Residential LV	TAS31	217,966	119.6
	Uncontrolled LV heating	TAS41	209,534	53.9
	Business LV General	TAS22	29,041	37.7
Evoenergy	Residential basic	10,011	129,356	73.3
	General supply non-TOU	40,041	11,158	25.8
Power and Water	Domestic		74,518	86.1
	Commercial		13,127	54.2

Source: AER analysis

Table 18-13 Current cost reflective network tariffs by selected electricity distributor

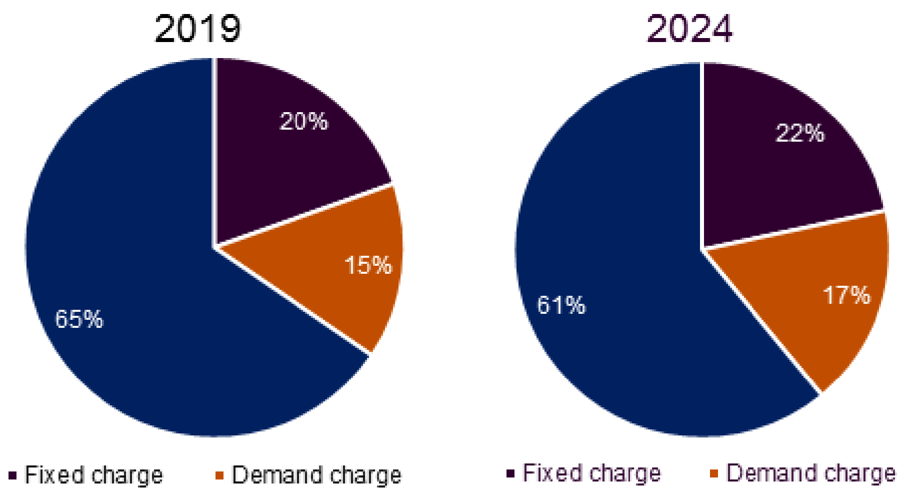
Electricity Distributor	Network Tariff Name		Customer Numbers in 2018-19	NUOS Revenue ($m) in 2018-19
Ausgrid	Residential TOU	EA025	354,965	238.9
	Small business TOU	EA225	75,618	134.2
Endeavour Energy	Residential TOU	N705	31401	0.02
	General Supply TOU	N84	11053	14.7
Essential Energy	Residential TOU	BLNT3AU	31401	23.1
	LV TOU < 100MWh Urban	BLNT2AU	11053	70.5
TasNetworks	Residential TOU	TAS93/92	6,207	3.8
	Residential TOU demand	TAS87	219	0.2
	LV Business TOU	TAS94	4,289	33.7
Evoenergy	Residential	015, 016,025,026	40,800	32.8
	LV TOU/Demand	101, 104,106,107	4,835	81.3
Power and Water	LV Smart		0	0
	LV>750MWh		166	20.5

Source: AER analysis

Endeavour Energy's network use of system tariffs

The following figure shows the annual Network Use of System revenue share by charging parameter type for the major published tariffs.

Figure 18-13 Network revenue share by charging parameter - Endeavour Energy

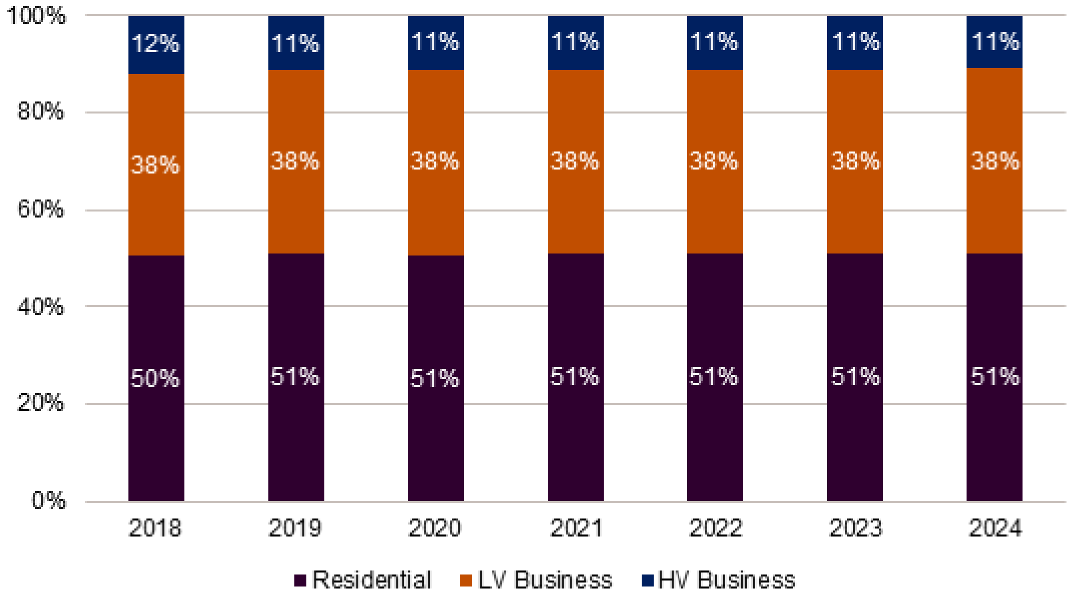


Source: AER analysis

The figure above highlights that Endeavour proposes to moderately re-balance its network use of system tariffs over the next five years, largely as a result of the expected increase in the penetration of cost reflective pricing.

Endeavour is forecasting that the residential customer will account for just over half of their annual network revenue entitlement in the next regulatory control period, see figure below.

Figure 18-14 Forecast network revenue share by customer segment - Endeavour Energy



Source: AER Analysis

Comparison with other distributors' pricing proposals in next regulatory control period

From a regulatory compliance perspective, the AER is focused on whether the network pricing approach set out in Endeavour energy's tariff structure statement proposal will contribute to the achievement of the Network Pricing Objective in Chapter 6 of the NER and in turn the broader National Electricity Objective in the NEL. 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:

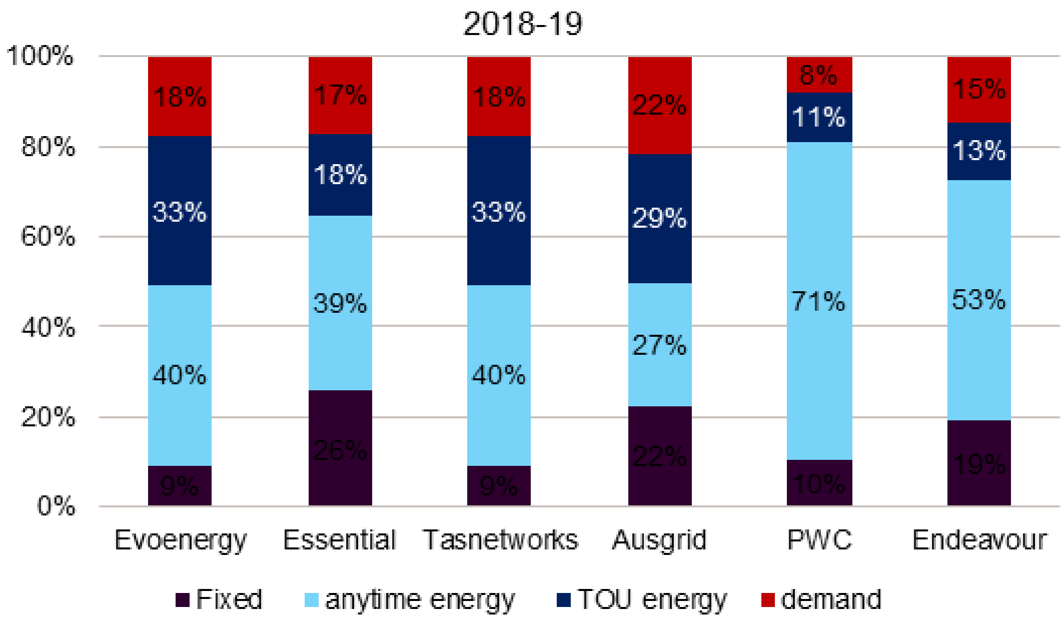
Progress towards efficient recovery of residual costs

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 because changes in the level of the fixed charge typically do not 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 increase does not contravene the customer impact principle in the NER.[94]

[94] NER, cl 6.18.5(h).

The following figure provides a comparison by electricity distributor of the current network revenue share by charging parameter.

Figure 18-15 Comparison of network revenue share by charging parameter by electricity distributors

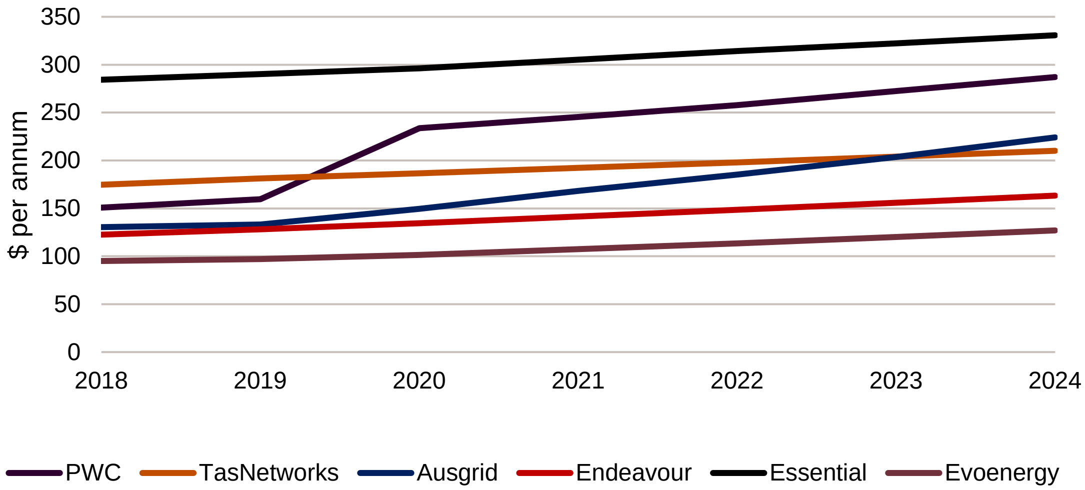


Source: AER analysis

It is clear from the figure above shows that the current reliance on fixed charges varies considerably across individual electricity distributors. It is interesting to note that the NSW electricity distributors currently recover materially higher share of their annual revenue requirement from fixed charges compared to Power and Water Corporation, TasNetworks and Evoenergy.

The figure below provides insights into the extent that the electricity distributors propose to increase the level of the residual fixed charge in the next regulatory control period.

Figure 18-16 Forecast of residential fixed charge by electricity distributors



Source: AER analysis

The key points from the above comparison from an Endeavour perspective is that it currently has the lowest fixed charge for the flat energy tariff of the NSW electricity distributors. It is also evident from the figure above that Endeavour proposes to adopt a gradual approach to fixed charge increases over the next five years, particularly compared to Ausgrid and Power and Water Corporation.

Progress towards LRMC-based pricing

Consistency with this aspect to the distribution pricing principles set out in the NER is achieved by setting peak charges reflective of long run marginal cost estimates, ensuring peak charging windows accurately reflect times of network congestion and assigning more customers to cost reflective network tariffs.

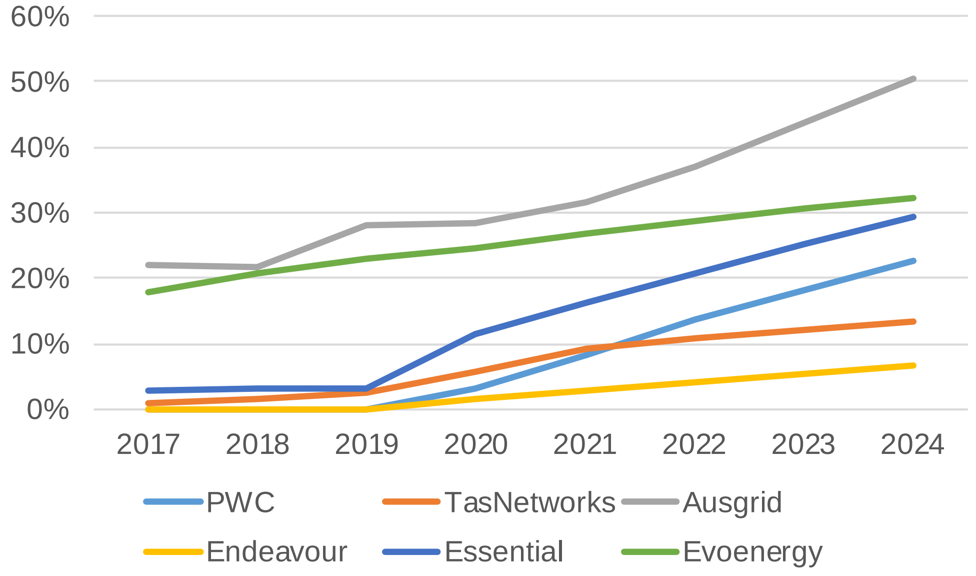
The key drivers of the assignment of customers to cost reflective tariff are the penetration of interval metering and the procedure for assigning and re-assigning customers to tariffs.

As discussed in section A.4 of this appendix, the electricity distributors expect to see a material increase in the penetration of interval metering over the next five years. This will enable these electricity distributors to potentially achieve a substantial increase in the penetration of cost reflective pricing in the residential and small business customer segment.

Endeavour expects to have around a third of its customers with interval metering installed in their premise by the end of the next regulatory control period. As a result of its less aggressive approach to the introduction of cost reflective pricing, Endeavour is forecasting a moderate increase in the number of residential and small business customers assigned to a network transitional demand tariff over the next five years, as shown in the figure below.[95]

The following figure shows forecast penetration of cost reflective network pricing in the residential customer segment over the next regulatory control period by electricity distributor.

Figure 18-17 Comparison of forecast penetration of residential cost reflective pricing by electricity distributors



Source: AER analysis

It is interesting to note that unlike other electricity distributors, Endeavour 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 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.

Retail Electricity Pricing in the Endeavour Energy's network area

The electricity and gas retail markets in NSW are competitive, so all customers in NSW can choose their retailer and electricity and gas plans. Customers who do not choose a plan are automatically moved onto their retailer's default standing offer.

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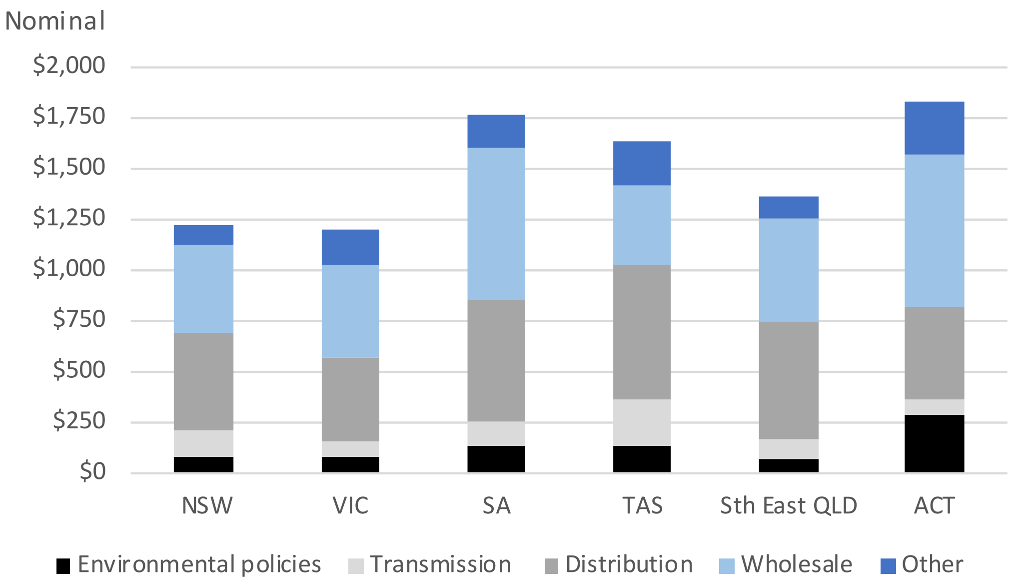
95 This forecast does not include customers that elect to opt-in to the cost reflective tariff during the next regulatory control period.

The NSW Independent Pricing and Regulatory Tribunal (IPART) review of the performance and competitiveness of the NSW electricity retail market found that competition in the retail electricity market in NSW continued to develop, with more retailers entering the market and the market share of smaller retailers increasing, more than three quarters of customers on market offers, and a substantial portion of customers switching retailers or offers.

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.

Figure 18-18 Annual electricity supply chain costs by NEM region



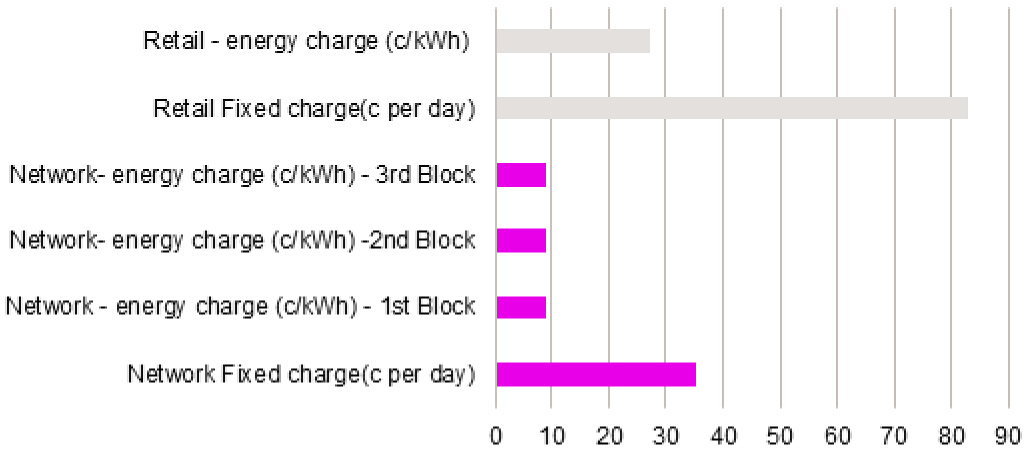
Source: AEMC 2018

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

Origin Energy is the local area retailer for customers living in the Endeavour network area. Origin Energy are obliged to provide a standing offer to small customers[96] that have not signed up to a market offer.

Origin Energy currently offers a standard retail anytime energy consumption tariff for residential and small business customers using less 100 MWh per annum of electricity. Origin Energy has adopted simple two part at the retail level - fixed charge and a single anytime energy charge. Interestingly the Endeavour has adopted a more complicated four part structure for the underlying network tariff – fixed charge and a three block anytime energy charge. As highlighted in the figure, Endeavour has applied the same anytime energy price for each of three blocks at the network level – effectively converting the block structure into a single anytime energy charge.

Figure 18-19 Comparison of network and retail standing offer - flat energy tariff



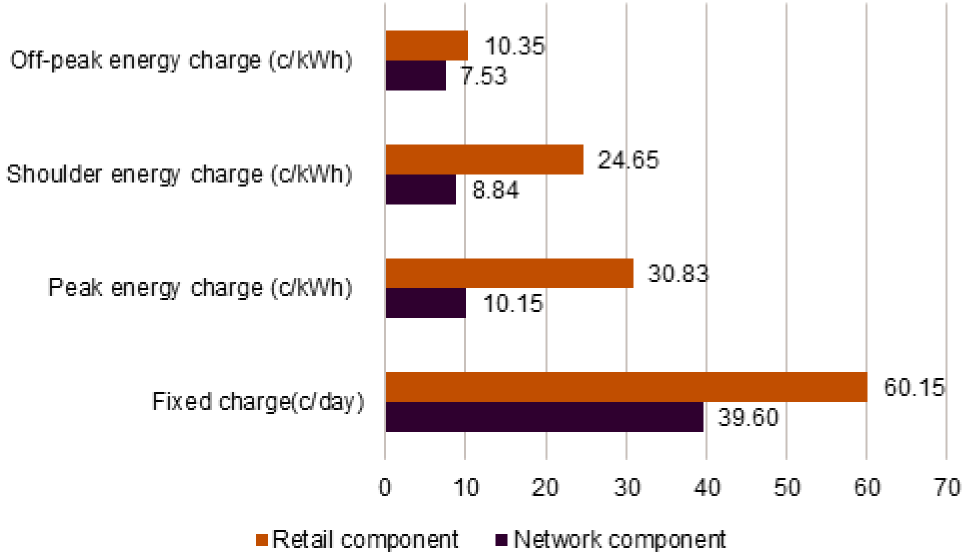
Source: AER analysis

Origin Energy currently offers a voluntary retail standing offer under a Time of Use energy structure for residential and small business customers located in Endeavour's network area.

96 A small customer is defined as a customer that uses less than 100 MWh of electricity per annum and is supplied through a low-voltage connection to the electricity distribution network.

The current residential prices for this tariff are shown at the network and retail level in the figure below:

Figure 18-18 Comparison of network and retail standing offer - Time of use energy tariff



Source: AER analysis

B Tariff design and assignment policy principles

Under the NER, the objective of tariff reform is to introduce cost reflective pricing.[97] 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[98]
- contemplate whether customers are going to be able to understand the charges they are likely to see.[99]

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?

[97] NER cl 6.18.5(a).

[98] NER cl. 6.18.5(h).

[99] NER cl. 6.18.5(i).

When should tariff assignment happen?

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

A distributor's tariff assignment policy are the rules the distributor follows to allocate network tariffs to customers. 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).[100]

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 and their ability to understand these tariff strategies is an important element of fostering and maintaining users' support for tariff reform generally.[101] If distributors adopt the same (re)assignment triggers there will be a more regular and consistent pace of tariff reform across distributors and jurisdictions.

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

[101] NER cl. 6.18.5.

New customers should face cost reflective tariffs

When new customers connect to the distribution network, the distributor should assign them a cost reflective tariff immediately. Each distributor, except TasNetworks, proposed to assign new customers to cost reflective tariffs in this manner.[102]

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[103] and investment in energy efficiency in the construction of a new building/premise[104]
- newly connected customers are less likely to be surprised by their network charges even where they are moving premises. This is because as they either have no prior tariffs to compare with or prior tariffs were at another connection with different appliances and heating, cooling or lighting needs.

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.[105]

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 tariff structure statements that proposed reassignment to cost reflective tariffs included reassigning customers that upgrade their connections to cost reflective tariffs (see Table 18-14).

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

103 See D.4.1.

104 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

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

Table 18-14 Distributor’s proposed reassignment triggers

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

We note that the 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 customers 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.

We consider that customers with new connections or have upgraded their connection are more likely to understand the impact of cost reflective network tariffs on their retail bills. This is because these customers are:

- actively engaged either by investing in upgrading their connections or through considering electricity efficiency when preparing for a new connection, and
- expecting to see a change in their retail electricity bills due to the changing or upgrading their network connection.

Even so, we consider that these customers may also benefit from a 12-month data-sampling period. We would like to hear from distributors and other stakeholders, on whether distributors should provide all customers a 12-month data-sampling period to help customers better engage with their electricity charges and usage.

Retail price regulation will influence tariff reassignment

In some jurisdictions, such as Tasmania and the Northern Territory, there is retail price regulation. Retail price 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 tariff 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.[106]

Each distributor, except TasNetworks, proposed default assignment to cost reflective tariffs in their tariff structure statements we received in the first half of 2018.[107]

With default assignment to cost reflective tariffs, distributors need to consider whether to offer customers optional tariffs. Broadly, we see three possibilities (all derived from tariff structure statement 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

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

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

- 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 including anytime tariffs) instead of being prescribed to a default network tariff.

We are comfortable that distributors should offer customers a choice of cost-reflective tariffs because:

- allowing customers to choose between a suite of tariffs enables them to match their behaviour to price signals, offers them the ability to choose the tariff they understand best—and presumably will therefore respond to—and mitigates any potential adverse cost impacts from the move to cost reflective tariffs. This engenders greater customer acceptance of change.
- 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.[108] They give the retailer the ability to face flat energy charges. These charges are easy for customers to understand.[109] 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 long term. That's not in the long term interest of customers.

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

We consider that distributors should no longer offer customers who are on a cost reflective tariff the ability 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

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108 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.

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

structures.[110] 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 but that is a choice for them in their ongoing management of market contracts and spot prices.

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 a distributor's cost reflective *network* tariffs for those same customers). All else equal, if retailers are unable to convince customers on 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 this additional risk.[111] That would actually leave all customers worse off over time. 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 retail price regulation applies.

The ACCC supported prescribed tariffs

The ACCC's Retail Electricity Pricing Inquiry advocated 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
- a requirement for retailers to offer flat energy retail tariffs to customers that distributors charge more cost reflective network tariffs to
- additional targeted assistance for vulnerable customers.[112]

These ACCC suggestions should be considered as a package of recommended changes to the existing NEL and NER requirements.

[110] 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)).

[111] 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.

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

In contrast, our current task is to apply the prevailing 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 beyond hardship assistance plans and jurisdictional concessions. This means we cannot impose these requirements on retailers through our approval of distribution network service providers' tariff structure statements. We consider that without implementation of the complementary measures the ACCC recommended in its inquiry, 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 could occur if retailers do not offer customers a flat energy tariff or innovative tariff designs that end-users can understand and feel comfortable with. In its work for the ACCC, the CSIRO found that most retailers pass on the structure of cost reflective network tariffs to end-users; this would mean these customers have very little choice of retail tariffs available to them.[113]

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

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 be an effective means to progress tariff reform. In the Northern Territory, Power and Water Corporation proposed a prescribed assignment policy for residential customers.[114] However, as noted earlier, the Northern Territory Government regulates and subsidises retail electricity prices.[115] 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

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

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

[115] 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 encourage 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.[116]

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

We consider that by allowing customers to have a choice between different cost reflective tariffs improves their support for reform. Cost reflective tariff choice 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
- 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.[117] Essential Energy also proposed this approach for customers with new technology.[118]

These methods 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.

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

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

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

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 accompanied with flat energy charges
        - 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 flat tariffs, whose benefits are simplicity 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 permit 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
- 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:

- 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 on coldest days turn on their electric heating, while transport systems and businesses are still operating at or near full capacity
- 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
- time of use tariffs where distributors charge customers based on their total electricity consumed during peak and off-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 the box 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)[119]

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;

[119] 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.[120]

The residential time of use energy tariff designs proposed by distributors are summarised in Table 18-15 below.

Table 18-15 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:

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120 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.

- 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).[121]

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.

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[122]

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

- 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.[123]

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.[124]

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 18-16.

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[122] 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.

[123] 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.

[124] Australian Competition and Consumer Commission, Restoring electricity affordability and Australia's competitive advantage, Retail Electricity Pricing Inquiry Final Report, June 2018, p. 182.

Table 18-16 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.

Note: We have not included Ausgrid's demand charge for residential customers, as it was not well defined.

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.[125] 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, 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.

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

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:

- 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 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[126] and customers' ability to understand tariffs[127] 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.[128] By comparison, Endeavour's proposed demand charge would cover over 1,000 hours a year,[129] and Ausgrid's seasonal peak time of use energy tariff would cover over 800 hours a year[130]
- 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[131]
- the extent to which costs vary between different locations.[132]

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:

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126 NER, cll. 6.18.5(e)(f) and (g).

127 NER, cl. 6.18.5(i).

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

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

130 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.

131 NER cl. 6.18.5(f)(2).

132 NER cl. 6.18.5(f)(3).

- 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.[133] Energex and Ergon Energy are both offering energy subscription 'lifestyle' tariffs, where customers subscribe to a maximum quantity of energy consumption during peak hours[134]
- 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.[135]

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 tariff structure statement in the future.

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[133] 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.

[134] 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.

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

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.

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 18-17 below.

Table 18-17 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 18-18 below.

Table 18-18 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.[136]

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.[137] 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.[138] 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 NER require network tariffs to be based on LRMC.[139] 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,

136 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.

137 NER, chapter 10 Glossary.

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

139 NER, cl. 6.18.5(f).

distributors would not recover all their costs. Costs not covered by a distributor's LRMC are called 'residual costs'. The NER require network tariffs to recover residual costs in a way that minimises distortions to the price signals for efficient usage that would result from tariffs reflecting only LRMC.[140] 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.[141] We consider this aspect in section 18.4.1.1and 18.4.2.1.

Assessment approach

This is the second tariff structure statement round for the electricity distribution businesses undergoing a distribution determination.[142] In this round, we are assessing the extent to which a distributor made improvements to its methods for estimating LRMC compared to the first tariff structure statement round. In particular, we assessed whether a distributor:

- investigated the inclusion of replacement capex (repex) in their LRMC calculations[143]
- used a minimum of 10 years of forecast data in the calculation of LRMC[144]
- continued to refine their methods for estimating LRMC so their tariffs better reflect efficient costs.[145]

These are the improvements we encouraged distributors to explore in our final decisions for the first tariff structure statement 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 NER, particularly the requirement that a distributor's method(s) of calculating LRMC has regard to:[146]

- the costs and benefits of implementing the method(s) of calculating LRMC

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

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

142 The exception is Power and Water Corporation, which 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 Corporation to guide it in developing its first TSS.

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

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

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

146 NER, cl 6.18.5(f).

- the additional costs of meeting demand from customers at times of greatest utilisation of the relevant part of the distribution network
- the location of customers and the extent to which costs vary between different locations in the distribution network.[147]

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 NER.

We discuss each of our criteria in more detail below.

Inclusion of repex in LRMC estimates

In our final decision for the first tariff structure statement 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 tariff structure statement round, we noted the NER 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.[148] 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

[147] 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.

[148] NER, chapter 10—Glossary.

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 at levels consumers' value.[149]

We also noted not all types of repex should be included in LRMC estimates.[150] Marginal cost refers to the cost of an incremental change in demand.[151] 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 tariff structure statement 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 tariff structure statement round.[152]

Definition of 'long run'

In our final decision for the first tariff structure statement 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'.[153]

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 tariff structure statement round.

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

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

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

152 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 Corporation, Ausgrid, Endeavour Energy and Essential Energy).

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

The NER 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.[154]

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 accurate forecasts over such a long horizon. The longer the estimation period, the more difficult it becomes to estimate and forecast long run costs.[155]

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 NER.

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

[154] NER, chapter 10.

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

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

Assessment criteria:

In this second tariff structure statement 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 tariff structure statement round.

In the first tariff structure statement 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 sophisticated approaches, such as the Turvey approach if they consider it appropriate.[157]

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.[158]

A key question in our assessment (and for distributors in making their tariff structure statement) is whether the benefits of more accurate estimates of LRMC outweigh the costs of deriving them.[159] This cost-benefit equation will depend on the circumstance of each business.

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

[158] 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.

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

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).[160] 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.[161]

  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).[162] Accordingly, basing tariffs on an estimate of average LRMC or a part of the network's LRMC sends inefficient price signals to most, if not all, customers.[163]

  Postage stamp pricing is less costly and simpler to administer for distributors and retailers than locational pricing.[164] 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 tariff structure statements.

- **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

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160 Such as demand charges or time of use charges.

161 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.

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

163 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.

164 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.

current version of the NER.[165] Distributors are transitioning their tariffs toward their LRMC estimates having regard to customer impacts.[166]

Future directions

As with the first tariff structure statement round, we encourage distributors to continue to refine their methods for estimating LRMC in the third tariff structure statement 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 tariff structure statement round. We consider the industry can use the learnings from this second tariff structure statement round to potentially consolidate the methods for including repex in LRMC estimates for subsequent tariff structure statement rounds.

As required by the NER, we will be mindful of the costs and benefits of improving LRMC estimation methods in our assessment of future tariff structure statement.[167] 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 tariff structure statement rounds. Factors to consider for the third tariff structure statement 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.

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165 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)).

166 NER, cl 6.18.5(h).

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

This should promote increasing penetration of interval meters in the NEM.[168] Distributors should monitor the rate of interval meter penetration and consider the extent to which it can accelerate tariff reform in the third tariff structure statement 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 tariff structure statement rounds, a distributor may experiment with using such methods if it proposes to trial tariffs in particular areas of its network, for example.[169]

  Also, having regard to location when estimating LRMC does not require a distributor to actually apply location-based pricing. In this second tariff structure statement round, for example, Endeavour produced two separate LRMC estimates: one for areas of stable or decreasing demand, and another for areas of increasing demand. However, Endeavour still proposed to apply postage stamp pricing for the 2019–24 regulatory control period.[170]

  Having LRMC estimates by location also has benefits beyond pure tariff setting. 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 NER requirement that LRMC estimates have regard to the extent to which costs differ between locations (without actually applying locational pricing).[171] It also provided Endeavour with further information regarding the appropriate LRMC estimate on which to base its prices.[172]

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

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168 The AEMC metering Rules do not apply in the Northern Territory. We consider Power and Water Corporation's metering proposal in AER, *Draft Decision: Power and Water Corporation Distribution Determination 2019 to 2024: Attachment 16: Alternative control services*, September 2018.

169 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.

170 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.

171 NER, cl 6.18.5(f)(3).

172 NER, cl 6.18.5(f).

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 tariff structure statement round to measure the different contributions to LRMC of augmentation capex and replacement capex.[173] 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 tariff structure statement round.[174]

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 tariff structure statement round who stated the industry should devote resources to improve the estimation of LRMC.[175] 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.

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

[174] 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.

[175] 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 Endeavour's retail customers for direct control services.[176] We approve Endeavour's 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 customers to tariff classes at the commencement of the next regulatory control period

1. Each customer who was a customer of Endeavour Energy immediately prior to 1 July 2019, and who continues to be a customer of Endeavour Energy as at 1 July 2019, will be taken to be “assigned” to the tariff class which Endeavour Energy was charging that customer immediately prior to 1 July 2019.

Assignment of new customers to a tariff class during the next regulatory control period

2. If, after 1 July 2019, Endeavour Energy becomes aware that a person will become a customer of Endeavour Energy, then Endeavour Energy 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 paragraph 2 or 5, Endeavour Energy will take into account one or more of the following factors:

   (a) the nature and extent of the customer’s usage;

   (b) the nature of the customer’s connection to the network; and

   (c) whether remotely–read interval metering or other similar metering technology has been installed at the customer’s premises as a result of a regulatory obligation or requirement.
4. In addition to the requirements under paragraph 3, Endeavour Energy, when assigning or reassigning a customer to a tariff class, will take into account the following:

   (a) that customers with similar connection and usage profiles are treated equally; and

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

(b) that customers which have micro–generation facilities are not treated less favourably than customers with similar load profiles without such facilities

(c) the national pricing objective and the distribution pricing principles which direct that tariffs charged by a distributor for direct control services should reflect the distributor's efficient costs of providing these services to the customer.

Reassignment of existing customers to another existing or a new tariff during the next regulatory control period

5. If Endeavour Energy believes that an existing customer's load characteristics or connection characteristics (or both) are no longer appropriate for that customer to be assigned to the tariff class to which the customer is currently assigned or a customer no longer has the same or materially similar load or connection characteristics as other customers on the customer's existing tariff, then Endeavour Energy may reassign that customer to another tariff class.

Notification of proposed assignments and reassignments

6. Endeavour Energy will 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 Endeavour Energy and that the customer's retailer may object to the proposed reassignment. This notice must specifically include reference to Endeavour Energy's published procedures for customer complaints, appeals and resolution.
8. If the objection is not resolved to the satisfaction of the customer's retailer under the Endeavour Energy's internal review system or the Energy and Water Ombudsman NSW (EWON), then the retail customer is entitled to seek a decision of the AER via the dispute resolution process available under Part 10 of the NEL.
9. If, in response to a notice issued in accordance with paragraph 7 above, Endeavour Energy receives a request for further information from a customer's retailer, then it must provide such information within a reasonable timeframe. If Endeavour Energy reasonably claims confidentiality over any of the information requested by the customer's retailer, then it is not required to provide that information to the retailer or retail customer. If the customer's retailer disagrees with such confidentiality claims, it may have resort to the dispute resolution procedures referred to in paragraph 7 above (as modified for a confidentiality dispute).
10. If, in response to a notice issued in accordance with paragraph 7 above, a customer's retailer makes an objection to Endeavour Energy about the proposed assignment or reassignment, Endeavour Energy must reconsider the proposed assignment or reassignment. In doing so Endeavour Energy must take into consideration the factors in paragraphs 3 and 4 above, and notify the customer's retailer in writing of its decision and the reasons for that decision.

11. If a customer's retailer objection to a tariff class assignment or reassignment is upheld, in accordance with Endeavour Energy's published procedures for customer complaints, appeals and resolution then any adjustment which needs to be made to tariffs will be done by Endeavour Energy as part of the next annual review of prices.

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

12. Where the charging parameters for a particular tariff result in a basis of charge that varies according to the customer's usage or load profile, Endeavour Energy will set out in its pricing proposal a method of how it will review and assess the basis on which a customer is charged.