DRAFT DECISION

Power and Water Corporation Distribution Determination 2019 to 2024

Attachment 18
Tariff structure statement

September 2018

AUSTRALIAN ENERGY REGULATOR

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Note

This overview forms part of the AER's draft decision on the distribution determination that will apply to Power and Water Corporation for the 2019–2024 regulatory control period. It should be read with all other parts of the draft decision.

The draft decision includes the following 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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Attachment 10 – Service target performance incentive scheme

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Shortened forms

Shortened form	Extended form
ACS	alternative control services
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
augex	augmentation expenditure
capex	capital expenditure
CCP	Consumer Challenge Panel
CCP 13	Consumer Challenge Panel, sub-panel 13
CESS	capital expenditure sharing scheme
CPI	consumer price index
DRP	debt risk premium
DMIAM	demand management innovation allowance (mechanism)
DMIS	demand management incentive scheme
distributor	distribution network service provider
DUoS	distribution use of system
EBSS	efficiency benefit sharing scheme
ERP	equity risk premium
Expenditure Assessment Guideline	Expenditure Forecast Assessment Guideline for Electricity Distribution
F&A	framework and approach
MRP	market risk premium
NEL	national electricity law
NEM	national electricity market
NEO	national electricity objective
NT NER or the rules	National Electricity Rules As in force in the Northern Territory

Shortened form	Extended form
NSP	network service provider
opex	operating expenditure
PPI	partial performance indicators
PTRM	post-tax revenue model
RAB	regulatory asset base
RBA	Reserve Bank of Australia
repex	replacement expenditure
RFM	roll forward model
RIN	regulatory information notice
RPP	revenue and pricing principles
SAIDI	system average interruption duration index
SAIFI	system average interruption frequency index
SCS	standard control services
SLCAPM	Sharpe-Lintner capital asset pricing model
STPIS	service target performance incentive scheme
WACC	weighted average cost of capital

Glossary of terms

Term	Interpretation
Apparent power	See kVA
Anytime demand tariff	A tariff incorporating a demand charge where the demand charge measures the customer's maximum demand at anytime (i.e. not limited to within a peak charging window).
CoAG Energy Council	The Council of Australian Governments Energy Council, the policymaking council for the electricity industry, comprised of federal and state (jurisdictional) governments.
Consumption tariff	A tariff that incorporates only a fixed charge and usage charge and where the usage charge is based on energy consumed (measured in kWh) during a billing cycle, and where the usage charge does not change based on when consumption occurs. Examples of consumption tariffs are flat tariffs, inclining block tariffs and declining block tariffs.
Cost reflective tariff	Consistent with the distribution pricing principles in the NER, a cost reflective distribution network tariff is a tariff that a distributor charges in respect of its provision of direct control services to a retail customer that reflects the distributor's efficient costs of providing those services to the retail customer. These efficient costs reflect the long run marginal cost of providing the service and contribute to the efficient recovery of residual costs.
Declining block tariff	A tariff in which the per unit price of energy decreases in steps as energy consumption increases past set thresholds.
Demand charge	A tariff component based on the maximum amount of electricity consumed by the customer (measured in kW, kVA or kVAr) which is reset after a specific period (e.g. at the end of a month or billing cycle). A demand charge could be incorporated into either an anytime demand tariff or a time-of-use demand tariff.
Demand tariff	A tariff that incorporates a demand charge component.
Fixed charge	A tariff component based on a fixed dollar amount per day that customers must pay to be connected to the network.
Flat tariff	A tariff based on a per unit usage charge (measured in kWh) that does not change regardless of how much electricity is consumed or when consumption occurs.
Flat usage charge	A per unit usage charge that does not change regardless of how much electricity is consumed or when consumption occurs.
Inclining block tariff	A tariff in which the per unit price of energy increases in steps as energy consumption increases past set thresholds.
Interval, smart and advanced meters	Used to refer to meters capable of measuring electricity usage in specific time intervals and enabling tariffs that can vary by time of day.
kW	Also called real power. A kilowatt (kW) is 1000 watts. Electrical power is measured in watts (W). In a unity power system the wattage is equal to the voltage times the current.
kWh	A kilowatt hour is a unit of energy equivalent to one kilowatt (1 kW) of power used for one hour.
kVA	Also called apparent power. A kilovolt-ampere (kVA) is 1000 volt-amperes. Apparent power is a measure of the current and voltage and will differ from real power when the current and voltage are not in phase.

Term	Interpretation
kVAr	Also called reactive power and is power used to maintain the electromagnetic fields of equipment. Low power factors are associated with higher levels of reactive power.
LRMC	Long Run Marginal Cost. Defined in the National Electricity Rules as follows: *"the cost of an incremental change in demand for direct control services provided by a Distribution Network Service Provider over a period of time in which all factors of production required to provide those direct control services can be varied".*
Minimum demand charge	Where a customer is charged for a minimum level of demand during the billing period, irrespective of whether their actual demand reaches that level.
NEO	The National Electricity Objective, defined in the National Electricity Law as follows: *"to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to—* *(a) price, quality, safety, reliability and security of supply of electricity; and* *(b) the reliability, safety and security of the national electricity system".*
NER	National Electricity Rules
Power factor	The power factor is the ratio of real power to apparent power (kW divided by kVA).
Tariff	The network tariff that is charged to the customer's retailer (or in limited circumstances, charged directly to large customers) for use of an electricity network. A single tariff may comprise one or more separate charges, or components.
Tariff structure	Tariff structure is the shape, form or design of a tariff, including its different components (charges) and how they may interact.
Tariff charging parameter	The manner in which a tariff component, or charge, is determined (e.g. a fixed charge is a fixed dollar amount per day).
Tariff class	A class of retail customers for one or more direct control services who are subject to a particular tariff or particular tariffs.
Time-of-use demand tariff (ToU demand tariff)	A tariff incorporating a demand charge where the demand charge measures the customer's maximum demand during a peak charging window. A ToU demand charge might also include an off-peak demand change or minimum demand charge, and may include flat, block or time-of-use energy usage charges.
Time-of-use energy tariff (ToU energy tariff)	A tariff incorporating usage charges with varying levels applicable at different times of the day or week. A ToU energy tariff will have defined charging windows in which these different usage charges apply. These charging windows might be labelled the 'peak' window, 'shoulder' window, and 'off-peak' window.
Usage charge	A tariff component based on energy consumed (measured in kWh). Usage charges may be flat, inclining with consumption, declining with consumption, variable depending on the time at which consumption occurs, or some combination of these.

18 Tariff structure statement

This attachment sets out our draft decision on Power and Water's tariff structure statement to apply for the 2019–24 regulatory control period.

A tariff structure statement applies to a distributor's tariffs for the duration of the regulatory control period. It describes a distributor's tariff classes and structures, the distributor's policies and procedures for assigning customers to tariffs, the charging parameters for each tariff, and a description of the approach the distributor to setting tariffs in pricing proposals. It is accompanied by an indicative pricing schedule.[1] A tariff structure statement provides consumers and retailers with certainty and transparency in relation to how and when network prices will change.

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

- providing better price signals—tariffs which reflect what it costs to use electricity at different times allow customers to make informed decisions to better manage their bills
- transitioning tariffs to greater cost reflectivity—with the requirement that distributors explicitly consider the impacts of tariff changes on customers, by engaging with customers, customer representatives and retailers in developing network tariff proposals
- managing future expectations—providing guidance for retailers, customers and suppliers of services such as local generation, batteries and demand management by setting out the distributor's tariff approaches for a set period of time.

Background to this decision

This is Power and Water's first 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 account for impacts on consumers.

In the future direction section of our final decisions for the first round of tariff structure statements, we noted that transitioning to cost reflective pricing will take more than one regulatory control period to achieve.[3] We set an expectation that to comply with the

1 NER, cl. 6.18.1A(a).

2 NER, cl. 6.18.5.

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

NER, each tariff structure statement proposal improve the cost reflectivity of network tariffs for the forthcoming regulatory control period.[4]

Our future directions were available for Power and Water's consideration in developing its first tariff structure statement. We therefore make this draft decision with the expectation that Power and Water's tariffs moved towards improved cost reflectivity compared to its tariffs from the 2014–19 regulatory control period. Nonetheless, we were cognisant during our assessment that this is Power and Water's first distribution determination under the NER. We sought to achieve the appropriate balance having regard to these factors in this draft decision.

18.1 Power and Water Corporation’s proposal

Power and Water submitted its first ever proposed tariff structure statement on 31 January 2018 for our assessment.

Figure 18.1 summarises Power and Water’s tariffs and tariff classes in the 2014–19 regulatory control period and those in it proposes for the 2019–24 regulatory control period. For both regulatory control periods, Power and Water categorised tariffs and tariff classes according to:

- the part of the network a customer is connected to (either the high voltage, HV, or the low voltage, LV, network)
- the customer's annual consumption—broadly, those who consumed:
    - more than 750 MWh per annum (large customers)
    - less than 750 MWh per annum (small customers).

Power and Water's classification of customers by this annual consumption follows the thresholds set by the Electricity Pricing Order (the Order). The Order sets caps on the prices electricity retailers can set for small customers in the Northern Territory. We discuss the Order in more detail in appendix A.

[4] For example see AER, *TasNetworks distribution final determination 2017– 19, Attachment 19 Tariff structure statement* April 2017 p. 12.

Figure 18.1 Power and Water's tariffs across the 2014–19 and 2019–24 regulatory control periods

2014-19 period

Tariff class	Tariff
Commercial HV	Commercial HV >750 MWh pa
Commercial	Commercial LV >750 MWh pa Commercial LV <750 MWh pa Unmetered - Street lighting Unmetered - Traffic lights
Domestic	Domestic

Proposed TSS for 2019-24 period

Tariff	Tariff class
> 750 MWh pa Individually calculated customer tariff > 750MWh pa HV < 750 MWh pa	HV
LV customers consuming >750 MWh pa Individually calculated customer tariff >750 MWh pa	LV >750 MWh pa
Non-residential - Accumulation meter Unmetered - Street lighting + similar 12 hr unmetered Unmetered - Traffic lights + similar 24 hr unmetered Residential - Accumulation meter Smart meter LV between 40 and 750 MWh pa Smart meter LV <40 MWh pa	LV <750 MWh pa

Note: Tariffs in red font are proposed tariffs that do not have an equivalent in the 2014–19 regulatory control period.

Power and Water proposed to introduce several major changes to its tariffs, including:

- demand tariffs for small customers (Smart Meter LV consumer <750 MWh pa)
- amendments to unmetered tariffs:
  - adoption of a demand-based charging parameter
  - relabelling, based on period of use
- removal of the declining block structure from large customer tariffs
- individually calculated tariffs for large customers
- introduction of an excess kVAr charge in demand tariffs applicable to customers who consume more than 40 MWh per annum
- peak charging windows based on seasons.

18.2 Draft decision

Our draft decision is to accept the following elements of Power and Water's tariff structure statement, as we consider that these contribute to compliance with the distribution pricing principles and to the achievement of the network pricing objective:

- the prescribed tariff assignment policy for all customers[5]
- tariff structures for small customers[6]

[5] Customers on a 'prescribed' tariff cannot opt-out of this tariff and opt-in to an alternative tariff.

[6] In this draft decision, small customers are those consuming less than 750MWh per annum.

- tariff structures for large customers[7]
- peak charging windows
- method for estimating long run marginal cost.

However, our draft decision is also to not accept some elements of the tariff structure statement, and therefore to not approve the tariff structure statement as a whole, as we consider that each of these elements, and therefore the tariff structure statement as a whole, requires further work in order to fully comply with the distribution pricing principles in a manner that contributes to the network pricing objective. In particular, Power and Water should provide further information on:

- unmetered tariffs, particularly with regard to charging parameters and assignment policies (see section 18.4.2.2 for further discussion)
- individually calculated tariffs such as criteria for assigning customers to such tariffs and the method for determining the structures and levels of prices (see section 18.4.3 for further discussion)
- the approach it will use to set prices in each pricing proposal over the 2019–24 regulatory control period (see section 18.4.4.2 for further discussion).[8]

We commend Power and Water for the significant consultation it undertook to develop its tariff structure statement, which we believe propose significant reforms to its existing suite of current tariffs.

We consider Power and Water's consultation process enabled it to propose improved cost reflectivity in its tariff structures while accounting for the customer impact principle.[9] Power and Water proposed a relatively small suite of tariffs, which reduces administration costs for its customers. In particular, Power and Water's proposal for prescribed demand tariffs to small customers with smart meters is a significant and positive tariff reform. Power and Water also made significant improvements to its peak charging windows so they send stronger signals of when the network is likely to be congested. This includes applying the peak charging window only during the summer/wet season for small customers.

18.3 Assessment approach

This section outlines our approach to tariff structure statement assessments.

There are two sets of requirements for tariff structure statements. First, the NER sets out a number of elements that an approved tariff structure statement must contain.[10]

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7 In this draft decision, large customers are those consuming more than 750MWh per annum.

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

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

10 NER, cl. 6.18.1A(a).

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

What must a tariff structure statement contain?

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

- the tariff classes into which retail customers for direct control services will be divided
- the policies and procedures the distributor will apply for assigning retail customers to tariffs or reassigning retail customers from one tariff to another
- structures for each proposed tariff
- charging parameters for each proposed tariff
- a description of the approach that the distributor will take in setting each tariff in each pricing proposal.

A distributor's tariff structure statement must be accompanied by an indicative pricing schedule with the tariff structure statement.[13] This guides stakeholder expectations about changes in network charges over the 2019–24 regulatory period.

What must a tariff structure statement comply with?

A tariff structure statement must comply with the distribution pricing principles for direct control services.[14] These may be summarised as:

- for each tariff class, expected revenue to be recovered from customers must be between the stand alone cost of serving those customers and the avoidable cost of not serving those customers[15]
- each tariff must be based on the long run marginal cost of serving those customers, with the method of calculation and its application determined with regard to the costs and benefits of that method, the costs of meeting demand from those customers at peak network utilisation times, and customer location[16]
- expected revenue from each tariff must reflect the distributor's efficient costs, permit the distributor to recover revenue consistent with the applicable distribution determination, and minimise distortions to efficient price signals[17]
- distributors must consider the impact on customers of tariff changes and may depart from efficient tariffs, if reasonably necessary having regard to:[18]

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

- the desirability for efficient tariffs and the need for a reasonable transition period (that may extend over one or more regulatory periods)
  - the extent of customer choice of tariffs
  - the extent to which customers can mitigate tariff impacts by their consumption.
- tariff structures must be reasonably capable of being understood by retail customers assigned to that tariff[19]
- tariffs must otherwise comply with the NER and all applicable regulatory requirements.[20]

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

> *The network pricing objective is that the tariffs that a DNSP charges in respect of its provision of direct control services should reflect the DNSP's efficient costs of providing those services to the retail customer.*[22]

Role of the Tariff Structure Statement

In 2014, the AEMC made important changes to the distribution pricing rules, including the process through which network tariffs are determined.

This included splitting the network pricing process into two stages.

Table 18.1 Two stage network pricing process

	Requirements
First stage	Distributors develop a proposed tariff structure statement to apply over the five year regulatory control period. The tariff structure statement outlines the distributor's tariff classes, tariff structures, tariff assignment policy and approach to setting tariff levels in accordance with the distribution pricing principles. This document is submitted to the AER for assessment against the distribution pricing principles in conjunction with the distributor's five year regulatory proposal. The AER then approves the tariff structure statement if it meets the distribution pricing principles and other National Electricity Rules requirements.
Second stage	Distributors develop and submit their annual pricing proposals to the AER. The annual pricing proposals essentially apply pricing levels to each of the tariff structures outlined in the approved tariff structure statement. The AER's assessment of the distributor's pricing proposal is a compliance check against the approved tariff structure statement and the control mechanism specified in the AER's

18 NER, cl.6.18.5(h).

19 NER, cl. 6.18.5(i).

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

21 NER, cl. 6.18.5(d)

22 NER, cl. 6.18.5(a)

regulatory determination.

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

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

What happens after a tariff structure is approved?

Once approved, a tariff structure statement will remain in effect for the relevant regulatory control period. The distributor must comply with the approved tariff structure statement when setting prices annually for direct control services.[23]

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

An approved tariff structure statement may only be amended within a regulatory control period with our approval.[24] We will approve an amendment if the distributor demonstrates that an event has occurred that was beyond its control and which it could not have foreseen so that the amended tariff structure statement materially better complies with the distribution pricing principles.[25]

18.4 Reasons for draft decision

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

23 NER, cl. 6.18.1A(c).

24 NER, cl. 6.18.1B.

25 NER, cl. 6.18.1B(d).

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

The section below sets out the reasoning for our decision on Power and Water's:

- tariff assignment policy (section 18.4.1)
- tariff structures for small customers (section 18.4.2) and large customers (section 18.4.3)
- tariff levels, including the calculation of long run marginal costs (section 18.4.4.1) and approach to setting tariffs (section 18.4.4.2)
- charging windows (section 18.4.5)

Also we discuss our assessment of the completeness and compliance of Power and Water's tariff structure statement with the requirements in the NER (section 18.4.6).

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

18.4.1 Tariff assignment policy

We consider Power and Water’s proposed tariff assignment policy contributes to compliance with the distribution pricing principles and to the achievement of the network pricing objective.

To assess Power and Water's tariff assignment policy against the NER requirements, we had regard to the tariff assignment policy principles set out in appendix B.

Power and Water suggested a prescribed assignment policy for all of its tariffs. Depending on customers' characteristics, Power and Water would assign them to one tariff only.[26]

Broadly, Power and Water proposed a relatively simple tariff reform strategy for the 2019–24 regulatory control period. It is offering fewer tariff options compared to other distributors in the NEM—for example, Power and Water did not propose any transitional tariffs (see Figure 18.1). We consider this strategy, in combination with factors that we discuss below, make a prescribed assignment policy appropriate.

Large customers, including individually calculated tariffs

Power and Water proposed two large customer tariffs for the 2014–19 regulatory control period: one for customers connected to the HV network, and another for customers connected to the LV network (see Figure 18.1).

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[26] Power and Water, *Response to information request #14 – Tariff structure statement - Public version (confidential material redacted)*, 23 May 2018, pp. 4–5.

Effectively, this means large customers were already under a prescribed tariff assignment policy. As we discuss in section 18.4.3, we consider Power and Water's proposed large customer tariffs for the 2019–24 regulatory control period are a positive move towards cost reflectivity. We therefore regard it as reasonable to continue with the prescribed tariff assignment policy for large customers.

The exception to the prescribed assignment policy is Power and Water's proposal to offer individually calculated tariffs to its large customers. As we discuss in section 18.4.3, we consider offering such tariffs to large customers is reasonable.

However, we require more information regarding how Power and Water proposes to administer such tariffs before we can be satisfied they contribute to compliance with the distribution pricing principles and to the achievement of the network pricing objective. For example, it is unclear from the proposal whether individually calculated tariffs are available to all of Power and Water's large customers, or whether such customers must meet certain criteria.[27]

Small customers

Tariff assignment for small customers will depend on their usage and connection characteristics. If they have accumulation meters they will continue to be on flat tariffs. As indicated in Figure 18.1, all small customers (except unmetered customers) were on these flat tariffs during the 2014–19 regulatory control period. The major change for the 2019–24 regulatory control period is Power and Water's proposal to assign small customers with a smart meter to its new demand tariff (see also section 18.4.2.1).

We consider a prescribed tariff assignment policy is appropriate even for small customers with a smart meter. We would normally consider that customers who change to a smart meter due to, for example, replacement of a faulty accumulation meter, should be assigned to a cost reflective tariff only after a 12 month delay. This is to give them time to analyse their interval data and consider adjustments to their electricity consumption patterns.

However, the Northern Territory Government's Electricity Pricing Order regulates electricity retail prices for all small customers. Any changes to underlying network tariffs therefore do not affect small customers at the retail level (but they do affect the retailer).[28]

We conclude that Power and Water's prescribed tariff assignment policy for small customers is therefore a positive move toward cost reflectivity, and that the Electricity

[27] Given this uncertainty, we refer to Power and Water's tariff assignment policy for its large customers as "prescribed" in this draft decision for simplicity's sake. We will revisit this issue after we receive Power and Water's revised proposal.

[28] The Electricity Pricing Order for the 2018–19 year is available from: www.jacanaenergy.com.au/news_and_publications/publications/tariffs_and_pricing/Northern_Territory_Pricing_Order_gazette_g26.pdf

Pricing Order leads to tariffs for small customers that take into account the customer impact principle.[29]

18.4.2 Tariff structures—Small customer tariffs

This section sets out our assessment of Power and Water's proposed tariffs for the following small customers:

- residential and non-residential
- unmetered usage.

18.4.2.1 Residential and non-residential customers

Power and Water proposed two types of tariffs for its residential and non-residential customers—flat tariffs and demand tariffs. We discuss our assessment of these tariffs in the following sub-sections.

Flat tariffs

We consider Power and Water’s proposed flat, anytime tariffs contribute to compliance with the distribution pricing principles and to the achievement of the network pricing objective.

Power and Water proposed to retain its legacy flat tariffs for small customers with an accumulation meter connected to the LV network.[30] There are two such legacy tariffs (one for residential customers and another for non-residential customers) which include a fixed charge and a flat usage charge.

For much of the 2014–19 regulatory control period, these legacy tariffs included a fixed charge and declining block charges. Power and Water had transitioned these declining block charges into a flat structure by the end of the 2014–19 regulatory control period.[31] We consider this is appropriate as flat tariffs better reflect the pricing principles.

As we noted for the NSW distributors, flat tariffs spread the recovery of residual costs equally across users in proportion to their consumption, whereas declining block tariffs allocate more residual costs to the lower consumption blocks.

Hence, flat tariffs better enable customers to mitigate the impact of changes through their usage decisions than a declining block tariff structure, where more costs are

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[29] NER, cll. 6.18.5(a) and (h).

[30] As we discuss in the 'Smart Meter tariffs' section, Power and Water are proposing tariffs for customers who consume less than 750 MWh per annum and connected to the HV network. There were no equivalent tariffs in the 2014–19 regulatory control period.

[31] Power and Water, *2018–19 Electricity Network Tariffs and Charges: Network Price Determination Version*, June 2018, p. 7.

recovered through the first consumption block.[32] Stakeholders also opposed declining block tariffs (in the NSW context) because they:[33]

- encourage consumption, which could result in the need for further network investment and ultimately higher costs to consumers in the long term
- disadvantage low consumption uses, which stakeholders typically consider are low income households.

Smart Meter tariffs (demand tariffs)

We consider Power and Water's proposed Smart Meter tariffs—which are demand tariffs—for small customers with a smart meter contribute to compliance with the distribution pricing principles and to the achievement of the network pricing objective. We consider the proposed Smart Meter tariffs move toward greater cost reflectivity while accounting for customer impact.[34]

However, we require Power and Water to amend its indicative price schedule for the excess kVAr charge of its Smart Meter tariffs in its revised proposal. In particular, the indicative prices for the 2019–20 and 2020–21 regulatory years should be set to zero (or "NA") to be consistent with the tariff structure statement.[35] Power and Water acknowledged this oversight and will reflect the proposed timing for the excess kVAr charge in its revised regulatory proposal.

Retailer Jacana Energy consider Power and Water's existing tariffs did not efficiently signal customers' costs on the network. Jacana Energy also consider existing tariffs sustained cross subsidies between customers with and without solar PV and did not provide efficient price signals for the take-up of new technologies and demand management.[36]

We consider Power and Water's proposed Smart Meter tariffs are positive steps towards addressing these concerns regarding Power and Water's existing flat tariffs.

Power and Water proposed to introduce the Smart Meter tariffs for small customers with an interval meter. As Table 18.2 summarises, Power and Water proposed to apply separate Smart Meter tariffs to small customers who consume:

- less than 40 MWh per annum and connected to the LV network.
- between 40 and 750 MWh per annum and connected to the LV network

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32 NER, cl. 6.18.5(a) and 6.18.5(h)(3). AER, Final Decision*: Tariff structure statements: Ausgrid, Endeavour and Essential Energy*, February 2017, p. 8.

33 AER, *Draft Decision: Tariff structure statement proposals: Ausgrid, Endeavour Energy, Essential Energy*, August 2016, p. 48.

34 NER, cl. 6.18.5(a), (g) and (h).

35 As we discuss in section 18.4.2, Power and Water stated it would not introduce the excess kVAr charge before 1 July 2021 due to customer feedback.

36 Jacana Energy, *Power and Water distribution determination*, 16 May 2018, pp. 1–2.

- less than 750 MWh per annum and connected to the HV network.

Table 18.2 Proposed smart meter tariffs for small customers

Tariff	Charging parameters	Charge
LV Smart Meter <40 MWh pa	Fixed charge	c/day
	Flat energy charge	c/kWh
	Seasonal demand charge (peak / off peak)(1)	$/kVA
LV Smart Meter 40<x<750 MWh pa	Fixed charge	c/day
	Flat energy charge	c/kWh
	Seasonal demand charge (peak / off peak) (1)	$/kVA
	Excess kVAr charge(2)	$/kVAr
HV Smart Meter <750 MWh pa	Fixed charge	c/day
	Flat energy charge	c/kWh
	Year-round demand charge (peak / off peak) (1)	$/kVA
	Excess kVAr charge(2)	$/kVAr

Source: Power and Water, *02.1 - Tariff Structure Statement - Public*, 16 March 2018, p. 41

(1) The 'seasonal demand charge' applies peak charges only during the summer months (October to March). The 'year round demand charge' applies the peak charges year round (see section 18.4.5 for our discussion on charging windows).

(2) The excess kVAr charge applies only to small customers consuming more than 40MWh per annum.

All three tariffs include a fixed charge, a flat energy charge and a demand charge—with the demand charge having a seasonal component for customers on the LV network. Power and Water also proposed to include an excess kVAr charge for customers who consume more than 40 MWh per to incentivise improvement of poor power factors.

Jacana Energy supported Power and Water's new tariff for customers with smart meters, noting cost reflective price signals are fundamental to the efficient operation and development of the network.[37]

Jacana Energy submitted that well-designed peak demand charges would provide the incentives for changes in customer behaviour that would ultimately lower network costs and bills.[38]

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37 Jacana Energy, *Power and Water distribution determination*, 16 May 2018, p. 1.

38 Behavioural changes include investment in energy efficient appliances, shifting consumption to off peak periods, or installing batteries. See Jacana Energy, *Power and Water distribution determination*, 16 May 2018, p. 2.

As we discuss in detail in appendix B, we consider demand tariffs are sufficiently cost-reflective to be used as a prescribed tariff at this stage of tariff reform. Further, they reinforce to customers that demand is an important network cost driver.

We also consider Power and Water's proposal to combine its monthly peak demand charge with a flat energy charge contributes to compliance with the distribution pricing principles and to the achievement of the network pricing objective. Power and Water proposed to apply the demand charge only in the wet/summer months, which is when small customers are likely to contribute to network congestion (see section 18.4.5 for our discussion on charging windows).[39] Meanwhile, the flat usage charge provides Power and Water with an avenue to recover its residual costs. They also provide customers with a charging parameter that is relatively simple to understand and enables them to mitigate the impact of tariff changes through their usage decisions.[40]

Power and Water proposed to include an excess kVAr charge to its Smart Meter tariffs for eligible customers who consume between 40 and 750 MWh per annum (see Table 18.2). We consider this charge contributes to compliance with the distribution pricing principles and to the achievement of the network pricing objective

Power and Water stated it set the level of its excess kVAr charge having regard to its long run marginal cost, or LRMC, estimates (see Table 18.4), equivalent tariffs from other networks, and the cost to the network of lower power factors.[41] However, it appears Ergon Energy's excess kVAr charge was the principal input in Power and Water's determination of the level of its excess kVAr charge.[42]

We note Ergon Energy applies its excess kVAr charges only to its largest customers.[43] On the other hand, Power and Water proposed to apply the excess kVAr charge to all customers with a smart meter consuming more than 40 MWh per annum, which can include small customers.[44] We asked Power and Water to explain why, pointing out that the demand charge component of the Smart Meter tariff already provides some incentive to improve poor power factors.[45]

Power and Water acknowledged the demand charge component of its Smart Meter tariffs provide some incentive to improve poor power factors as customers would pay for the additional kVA they use. But Power and Water considered this provides insufficient incentive to correct poor power factors. This is particularly the case for

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39 NER, cl. 6.18.5(f)(2).

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

41 Power and Water, *Response to information request 022 - Tariff structure statement - LRMC - Public*, 29 June 2018, p. 7.

42 Power and Water proposed $4 per excess kVAr per month, which is the same as Ergon Energy's equivalent charge in its approved TSS. See Power and Water, *Response to information request 022 - Tariff structure statement - LRMC - Public*, 29 June 2018, p. 7; Ergon Energy, *Revised proposal 2017 to 2020*, October 2016, appendix A.

43 Ergon Energy, *Revised proposal 2017 to 2020*, October 2016, pp. 32–35.

44 Power and Water, *2.1 – Tariff Structure Statement - Public*, 16 March 2018, p. 9.

45 AER, *Information request #040 - TSS - Excess KVAr charge*, 30 August 2018.

small customers where the demand charge applies in summer only.[46] The excess kVAr charge will therefore supplement the demand charge and will provide greater incentive for customers to meet the mandated technical requirements (see section 18.4.4.2).[47]

We accept Power and Water's reasons for proposing to apply the excess kVAr charge even to small customers (who consume more than 40 MWh per annum). We also note Power and Water is a much smaller network than Ergon Energy. We understand the thresholds at which individual customers with poor power factors can adversely affect the network is correspondingly smaller.

Further, Power and Water noted that small customers are currently under the Electricity Pricing Order and so are protected from bill shocks that may arise from implementing the excess kVAr charge. Power and Water also considered this charge may incentivise electricity retailers to develop appropriate pricing structures in the future.[48]

In principle, we consider introducing the excess kVAr charge is reasonable as a move along the cost reflective spectrum but have outstanding questions regarding the tariff levels Power and Water have set out in their indicative price schedule. We discuss this issue in section 18.4.4.2

The Consumer Challenge Panel (CCP13) recommended that Power and Water consider using tariff trials to improve understanding of consumer responses to price signals. CCP13 encouraged Power and Water to give preference to collaborative trials with Jacana, the dominant retailer in the Northern Territory.[49]

The rules enable distributors to conduct such tariffs trials outside of the tariff structure statement but under certain conditions.[50] While it is not a requirement in the rules, we encourage Power and Water to describe in its revised proposal any tariffs it is considering trialling for small (or large) customers in the 2019–24 regulatory control period.

18.4.2.2 Unmetered tariffs

Below, we provide our assessment of the two principal changes Power and Water proposed for its unmetered tariffs:

- adoption of a demand-based charging parameter

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46 Power and Water proposed off peak prices of $0/kVA at all times and days throughout the non-summer period. See sections 18.4.4.2 and 18.4.5 for more detailed discussion on tariff levels and charging windows, respectively.

47 Power and Water, *Response to information request 040 - Tariff structure statement - Excess kVAr charge - Public*, 6 September 2018, p. 1.

48 Power and Water, *Response to information request 040 - Tariff structure statement - Excess kVAr charge - Public*, 6 September 2018, p. 1.

49 CCP13, *Submission: Issues paper: Power and Water Corporation (PWC) electricity network revenue proposal 2019–24*, 16 May 2018, p. 43.

50 NER, cl. 6.18.1C.

- relabelling tariffs based on period of use.

Adoption of demand-based charging parameter

Power and Water initially proposed to replace the usage charges in its unmetered tariffs with demand charges.[51] However, Power and Water subsequently informed us it will change its approach and instead propose usage charges for these tariffs in its revised proposal on account of developments in the Northern Territory since submitting its initial tariff structure statement. At this stage, we have therefore not formed a view about Power and Water's initial proposal or its revised proposal (which has not yet been submitted).

The Local Government Association of the Northern Territory (the Association) noted Power and Water's proposed unmetered tariffs are measured in dollars per watt and are a fixed charged based on the installed wattage.

The Association is concerned this provides a disincentive for energy efficiency solutions involving smart controls to, for example, dim street lighting in off-peak hours and trim excess lighting.[52] The Association submitted maintaining a consumption charge for unmetered tariffs would remove these disincentives for the adoption of energy efficiency solutions.[53]

Power and Water informed us it has been in discussions with the Northern Territory Government regarding amendments to Chapter 7A of the rules. These discussions have indicated the Government will be adopting ‘AEMO like’ unmetered infrastructure load tables. Power and Water stated this development, along with the concerns raised by the Association, highlighted that a demand-based tariff may not be appropriate for unmetered tariffs for the 2019–24 regulatory control period. In order to address these issues, Power and Water is investigating options to adopt a consumption charge in its revised tariff structure statement.[54]

A consumption charge appears to address the Association's concerns and the potential amendments to chapter 7A of the rules. However, we reserve our assessment until Power and Water provides information regarding unmetered tariffs as the rules require.[55]

Power and Water also noted a number of potential timing risks regarding unmetered tariffs, namely it expects:[56]

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51 Power and Water, *2.1 – Tariff Structure Statement - Public*, 16 March 2018, p. 12; Power and Water, *2018–19 Electricity Network Tariffs and Charges – Network Price – Determination Version*, June 2018, p. 7.

52 Local Government Association of Northern Territory, *Power and Water 2019–24 proposal for electricity network distribution pricing*, 16 May 2018, p. 2.

53 Local Government Association of Northern Territory, *Power and Water 2019–24 proposal for electricity network distribution pricing*, 16 May 2018, p. 2.

54 Power and Water, *Email to AER staff: SCS Unmetered tariffs*, 27 August 2018.

55 NER, cl. 6.18.1A.

56 Power and Water, *Email to AER staff: SCS Unmetered tariffs*, 27 August 2018.

- the adoption of the load tables reflected in Chapter 7A will occur in 2019, after it submits the revised tariff structure statement
- installation of the Meter Data Management System to fully implement the new arrangements will not occur until post July 2019.

We expect the revised proposal to explain how Power and Water proposes to address these timing risks.

Relabelling tariffs based on period of use

We consider Power and Water's proposed relabelling of its unmetered tariffs does not contribute to compliance with the distribution pricing principles or to the achievement of the network pricing objective

As we discussed in the previous section, Power and Water are likely to amend the structure of its proposed unmetered tariffs to consumption-based structures. Power and Water stated this change may also affect the labelling of its unmetered tariffs. We therefore reserve our assessment of this aspect of Power and Water's proposed unmetered tariffs until we receive the revised proposal. In any case, we consider Power and Water should include in its revised proposal further information and principles to provide greater certainty regarding the allocation of customers to its unmetered tariffs.

Power and Water proposed to relabel its two unmetered tariffs based on the period of usage:[57]

- Unmetered supply 12 hour operation (12 hr tariff)—this tariff is for unmetered infrastructure with a 12 hour or less cycle such as street lighting
- Unmetered supply 12–24 hour operation (12–24 hr tariff)—this tariff is for unmetered infrastructure which operate for more than a 12 hour cycle or with a continuous 24 hour operation such as traffic lights and telecommunications infrastructure.

These differ slightly to the tariffs in the 2014–19 regulatory control period which, at least nominally, are based on the technology behind the usage. The 12 hr tariff is currently labelled as 'Street lighting and similar consumption profiled unmetered supplies'. The 12–24 hr tariff is currently the 'Traffic lights and similar unmetered 24 hour supplies'.[58]

The Association considered Power and Water should clarify the charging basis of its 12 hour and 12–24 hour unmetered tariffs. The Association considers there is potential for confusion as councils add smart controls to street lights. For example, the Association considers it is unclear whether Councils would be charged with the 12 hour

[57] Power and Water, *2.1 – Tariff Structure Statement - Public*, 16 March 2018, p. 18.

[58] Power and Water, *2018–19 Electricity Network Tariffs and Charges Network Price Determination Version*, June 2018, p. 5.

tariff for the operation of the lights, but the 12–24 hour tariff for the smart controls. The Association stated Power and Water have suggested solutions to certain councils but its statements remain unclear.[59]

The Association submitted that maintaining a consumption charge for unmetered tariffs would address the issues it identified regarding this relabelling.[60] As we discussed in the previous section, Power and Water will propose to adopt a consumption charge for unmetered tariffs in its revised proposal.

Power and Water stated the adoption of consumption charges for unmetered tariffs may affect the labelling of these tariffs. Power and Water stated it will review this aspect of its unmetered tariffs for its revised proposal.[61]

Given the developments regarding the amendments to chapter 7A of the rules (see previous section), we consider reviewing this aspect of its proposed unmetered tariffs is reasonable.

Regardless of the labels Power and Water adopts, we consider it can minimise doubt by listing the types of loads it will assign to the respective unmetered tariffs.

In addition, Power and Water should set out the principles and processes it would use where there is ambiguity as to which unmetered tariff should apply, as in the scenario that the Association described.

18.4.3 Tariff structures—Large customer tariffs

We consider that, in most respects, Power and Water's proposed tariffs for large business customers contribute to compliance with the distribution pricing principles and to the achievement of the network pricing objective

As we discuss below, the exception to this is Power and Water's proposal to offer individually calculated tariffs to very large customers.[62] We consider Power and Water must provide greater detail regarding these aspects in their revised proposal.

We also require Power and Water to amend its indicative price schedule for the excess kVAr charge in its revised proposal. In particular, the indicative prices for the 2019–20 and 2020–21 regulatory years should be set to zero (or "NA") to be consistent with the tariff structure statement.

We consider Power and Water has significantly improved the structure of its large business tariffs in terms of both moving toward greater cost reflectivity and accounting for customer impact with a less complex tariff design.

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[59] Local Government Association of Northern Territory, *Power and Water 2019–24 proposal for electricity network distribution pricing*, 16 May 2018, p. 3.

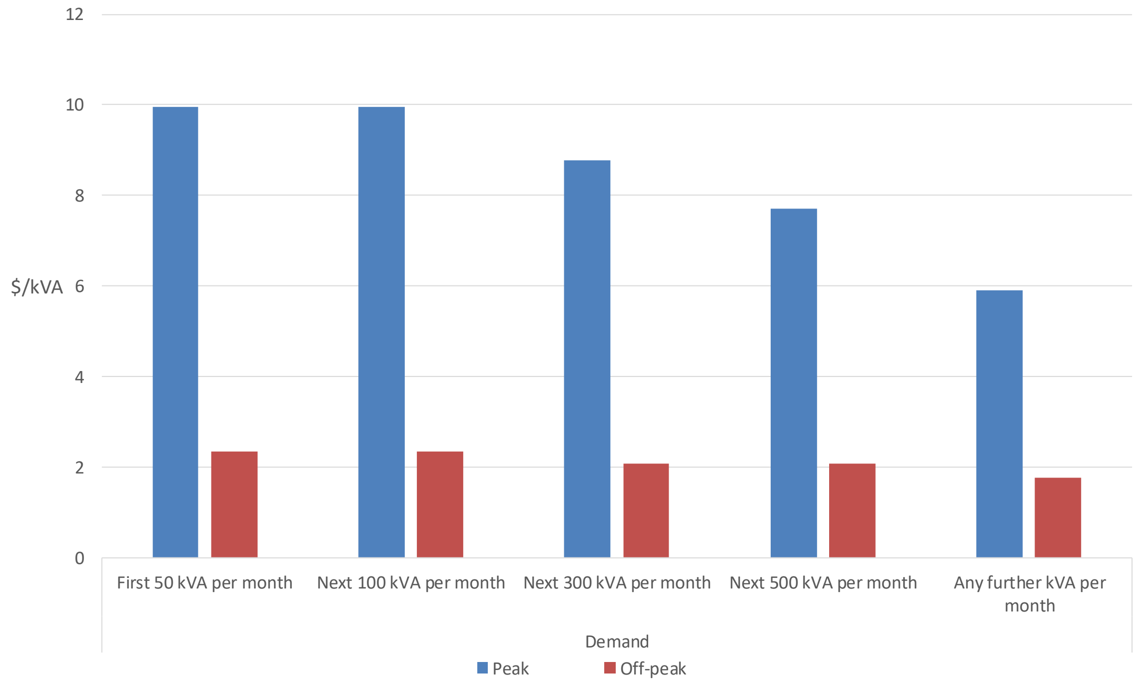
[60] Local Government Association of Northern Territory, *Power and Water 2019–24 proposal for electricity network distribution pricing*, 16 May 2018, p. 2.

[61] Power and Water, *Follow up to email to AER staff: SCS Unmetered tariffs*, 3 September 2018.

[62] For the latter, the discussion in section 18.4.2.1 also applies to large customers.

In the 2014–19 regulatory control period, Power and Water's large customer tariffs featured a complex structure which included a fixed charge, a demand charge and time-of-use energy charge. The demand and time-of-use energy charges were both disaggregated into peak and off-peak times, which were further disaggregated into a declining block structure. Figure 18.2 shows the declining block structure of the demand charge in Power and Water's tariff for large HV customers. The time-of-use charge of this tariff has a similar declining block structure.

Figure 18.2 Declining block demand charges for large HV customers



Source: Power and Water, *2018–19 Electricity Network Tariffs and Charges: Network Price Determination Version*, June 2018, p. 6.

Power and Water proposed to simplify its large business tariffs in the 2019–24 regulatory control period by removing the declining block structure and adopting a similar structure to the 'Smart Meter LV' tariff (see section 18.4.2.1). Indeed, Power and Water began the process of phasing out the declining block tariff structure during the 2014–19 regulatory control period.[63]

Replacing the declining block structure with a flat structure greatly simplifies tariff design, which reduces administrative burden on retailers, and provides better signals of efficient costs.[64] Further, application of the demand charge only during the peak window sends signals of when the network is likely to experience congestion.

63 As noted in section 18.4.1, Power and Water had largely phased out the declining block structure from its small customer usage charges during the 2014–19 regulatory control period.

64 AER, *Final decision: Tariff structure statements: Ausgrid, Endeavour and Essential Energy*, February 2017, p. 8.

Table 18.3 Proposed tariffs for large customers (HV and LV connected)

Charging parameters	Charge
Fixed charge	c/day
Flat energy charge	c/kWh
Year round demand charge (peak / off peak) (1)	$/kVA
Excess kVAr charge	$/kVAr

Source: Power and Water, *02.1 - Tariff Structure Statement - Public*, 16 March 2018, p. 42.

(1) The 'year round demand charge' applies the peak charges year round (see section 18.4.5 for our discussion on charging windows).

As we discuss in detail in appendix B, we consider demand tariffs are equally as cost reflective as other averaged tariff types with pre-defined peak periods. Further, they reinforce to customers that demand is an important cost driver.

We also consider Power and Water's proposal to combine its monthly peak demand charge with a flat energy charge contributes to compliance with the distribution pricing principles and to the achievement of the network pricing objective. Power and Water proposed to apply the demand charge year-round as large customers may contribute to network congestion at any time of the year (see section 18.4.5 for our discussion on charging windows).[65] Meanwhile, the flat demand charge provides Power and Water with an avenue to recover residual costs. They also provide customers with a charging parameter that is relatively simple to understand and enables them to mitigate the impact of tariff changes through their usage decisions.[66]

Power and Water proposed to include an excess kVAr charge to its large customer tariffs (see Table 18.3). As with the Smart Meter tariff for small customers, we consider introducing the excess kVAr charge is reasonable in principle (see section 18.4.2.1). An excess kVAr charge can provide incentives for customers to fix poor power factors, which in turn can lower the costs of running the network. However, we have questions regarding the tariff levels Power and Water have set out in their indicative price schedule. Section 18.4.4.2 discusses this issue.

As with the excess kVAr charge for small customers, Power and Water set the level of its excess kVAr charge having regard to various factors, but particularly Ergon Energy's equivalent charge (see section 18.4.1).

Power and Water discussed the introduction of the excess kVAr charge in consultations with large customers, and even held a dedicated session on this charging parameter.[67]

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65 NER, cl. 6.18.5(f)(2).

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

67 Power and Water, *02.1 - Tariff Structure Statement - Public*, 16 March 2018, pp. 14–15 and 33.

Some large customers requested more time to prepare for the introduction of the excess kVAr charge to allow time to design and budget for their power factor correction solutions.[68] Power and Water therefore proposed to introduce an excess kVAr charge no earlier than 1 July 2021.[69]

The indicative price schedule, however, included non-zero prices for all years of the 2019–24 regulatory control period, including the 2019–20 and 2020–21 regulatory years. Power and Water acknowledged the oversight and will reflect the proposed timing for the excess kVAr charge in the revised regulatory proposal.[70]

Individually calculated tariffs

We do not consider Power and Water's proposed individually calculated tariffs contributes to compliance with the distribution pricing principles or to the achievement of the network pricing objective.

The proposal to introduce individually calculated tariffs is reasonable of itself. However, we deem greater detail regarding these tariffs is required to enable proper assessment against the requirements of the rules.

Power and Water proposed to offer individually calculated tariffs to its large customers (it did not offer such tariffs in the 2014–19 regulatory control period) and such tariffs would have an individually calculated system access charge and demand charge. It may also include a volume (kWh) charge and an excess kVAr charge.[71]

However, Power and Water did not provide information beyond this. This reduces transparency and does not provide assurance that such tariffs will signal efficient costs. Its revised proposal should provide information that increases transparency regarding individually calculated tariffs, including:

- the eligibility criteria—the proposed tariff structure statement stated individually calculated tariffs are for “sufficiently large and unique customers”.[72] The revised proposal should provide further information regarding the criteria and thresholds for offering bespoke tariffs, such as metering requirements, connection characteristics and load characteristics
- the principles and methods on how Power and Water would calculate tariff levels for these bespoke tariffs—including how they are consistent with the pricing principles. Power and Water should explain the principles and approach it proposes to reflect long run marginal costs (LRMC) in its tariffs and how it would allocate residual costs. For example, Power and Water does not propose to utilise

68 Power and Water, *02.1 - Tariff Structure Statement - Public*, 16 March 2018, p. 15.

69 Power and Water, *02.1 - Tariff Structure Statement - Public*, 16 March 2018, p. 23.

70 Power and Water, *Response to information request 040 - Tariff structure statement - Excess kVAr charge - Public*, 6 September 2018, p. 6.

71 Power and Water, *02.2 - Tariff Structure Statement Overview - Public*, 16 March 2018, p. 25.

72 Power and Water, *02.2 - Tariff Structure Statement Overview - Public*, 16 March 2018, p. 25.

the LRMC estimates from its average incremental cost approach for its postage stamp tariffs (see section 18.4.4.1). Perhaps Power and Water can use the opportunity to utilise these estimates as the basis for setting tariff levels for their individually calculated tariffs.

We consider bespoke tariffs can contribute to compliance with the distribution pricing principles and to the achievement of the network pricing objective. They provide further opportunity to structure tariffs that reflect large customers' contribution to network costs.

Offering individually calculated tariffs is also a common practice in the NEM between distributors and their largest customers, who are likely to have the bargaining power and the information necessary to arrive at mutually beneficial and commercially negotiated outcomes.

We note distributors typically treat individually calculated tariffs as commercial in confidence. While we recognise there are valid reasons for this, we consider there should be transparency in the principles applied to determining these types of tariffs (without publishing the tariffs). This provides us with a framework for assessing annual pricing proposals.[73] This, in turn, ensures all tariffs applicable for any regulatory year are consistent with the pricing principles.[74]

18.4.4 Tariff levels

This section sets out our considerations of Power and Water's approach to:

- calculating long run marginal costs (LRMC)
- setting tariff levels over the 2019–24 regulatory control period, including how Power and Water proposed to:
    - reflect LRMC in their tariff structures
    - recover residual costs in their tariff structures.

An important feature of this draft decision is the concept of LRMC. LRMC is equivalent to the forward looking cost of a distributor providing one more unit of service, measured over a period of time sufficient for all factors of production to be varied.[75] Long run marginal cost could also be described as a distributor's forward looking costs that are responsive to changes in electricity demand.

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73 We must assess a pricing proposal's compliance with Part I of the NER (particularly rule 6.18) and with the applicable distribution determination, including the TSS (NER, cl. 6.18.8(a)(1)).

74 NER, cl. 6.18.5.

75 NER, chapter 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.

The NER requires network tariffs to be based on long run marginal cost.[76] However, not all of a distributor's costs are forward looking and responsive to changes in electricity demand. If network tariffs only reflected long run marginal cost, a distributor would not likely recover all its costs. Costs not covered by a distributor's LRMC are called 'residual costs'. The NER requires network tariffs to recover residual costs in a way that minimises distortions to the price signals for efficient usage that would result from tariffs reflecting only LRMC.[77]

This section sets out our considerations on Power and Water's approach to calculating LRMC (section 18.4.4.1), passing those costs through to customers and residual costs (section 18.4.4.2).

18.4.4.1 Calculating long run marginal cost

We consider Power and Water’s proposed method to estimate long run marginal costs (LRMC) contributes to compliance with the distribution pricing principles and to the achievement of the network pricing objective.

We used the framework detailed in appendix C as the basis our assessment regarding compliance with the pricing principles.

Below we describe Power and Water's approach to estimating LRMC. We then set out our assessment of this approach having regard to the framework in appendix C.

Power and Water LRMC estimation

Power and Water used a two-stage approach to estimate LRMC.

First, it used the average increment cost approach to determine its "system-wide" LRMC estimates.[78] Power and Water's average incremental cost approach calculated LRMC by taking ratio of the present value of growth related capex and opex to the present value of the forecast change in demand over the time horizon.[79] In these calculations, Power and Water:

- assumed opex is equal to a proportion of capex based on typical planning estimates[80]
- assumed 5 per cent of forecast replacement capex is 'growth related'
- used a time horizon of 19 years.[81]

Table 18.4 contains the LRMC estimates derived using the average incremental cost approach.

[76] NER, cl. 6.18.5(f).
[77] NER, cl. 6.18.5(g)(3).
[78] Power and Water, *02.1 Tariff structure statement - Public*, 16 March 2018, p. 30.
[79] Power and Water, *02.1 Tariff structure statement - Public*, 16 March 2018, pp. 29–30.
[80] Power and Water, *Regulatory proposal: Attachment 12.3P SCS pricing model*, 16 March 2018.
[81] Power and Water, *Regulatory proposal: Attachment 12.3P SCS pricing model*, 16 March 2018.

Table 18.4 Power and Water LRMC estimates

Tariff	LRMC from average incremental cost ($/kVA per month)	LRMC used in setting prices ($/kVA per month)
LV < 750 MWh	38.90	20.00
LV > 750 MWh	38.90	8.26
HV	18.38	7.16

Source: Power and Water, *02.1 Tariff structure statement - Public*, 16 March 2018, p. 30; Power and Water, *Response to information request 022 - Tariff structure statement - LRMC - Public*, 29 June 2018, p. 3.

However, Power and Water did not use these estimates directly to set the levels of its cost reflective tariffs. Power and Water considered these estimates were potentially too high given the flat demand forecast it received from the Australian Energy Market Operator. Power and Water was concerned these high estimates could provide incorrect signals to customers, noting that LRMC estimation is an imprecise science.[82]

Rather, Power and Water compared its estimates from the average incremental cost approach with the following sources:[83]

- the Northern Territory Utilities Commission's LRMC estimates from the 2014–19 regulatory control period
- the estimates of other electricity distributors in the National Electricity Market in recent TSS.

Power and Water then used these sources to derive the LRMC estimates that it used to set tariff levels (see Table 18.4).[84] Power and Water explained that the LRMC estimates that it used to set tariff levels are approximately at the mid-range of the various LRMC estimates it considered.

Assessment of LRMC approach

We consider Power and Water's proposed method to estimate LRMC contributes to compliance with the distribution pricing principles and to the achievement of the network pricing objective.

We discuss these in more detail below.

Estimation method

[82] Power and Water, *Response to information request 022 - Tariff structure statement - LRMC - Public*, 29 June 2018, pp. 1–2.

[83] Power and Water, *Response to information request 022 - Tariff structure statement - LRMC - Public*, 29 June 2018, p. 1.

[84] Power and Water, *02.1 Tariff structure statement - Public*, 16 March 2018, pp. 28–29.

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

As we noted above, Power and Water used a two-stage approach to estimating LRMC.

We consider the average incremental cost (AIC) approach is fit for purpose at this stage of tariff reform in the Northern Territory.

As we discuss in appendix C, LRMC largely depend on the level of congestion in different locations within a network (as well as temporal factors). However, postage stamp pricing applies across Power and Water's network and will continue to apply in the 2019–24 regulatory control period. Further, the Electricity Pricing Order, combined with the dominant market share of the incumbent retailer, limits the extent to which LRMC can be signalled through innovative retail tariff offerings (see appendix A). These factors limit the extent to which end customers can receive and respond to LRMC signals.

Further, interval meter penetration is still relatively low in Power and Water's network, particularly for customers consuming less than 40 MWh per annum (see also Figure 18.13).[85] Hence, it is unclear whether enough consumers would be able to respond to accurate LRMC signals to, in turn, signal efficient investment needs for Power and Water's network (see discussion in appendix C).

In this context, we consider the limitations of the average incremental cost approach—the perception that the estimates they derive are not the best representations of LRMC—are outweighed by its relatively low cost of implementation.[86] 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.

We also consider the second stage of Power and Water's method—where it compared the LRMC estimates from the average incremental cost approach with other estimates—is appropriate for Power and Water's first TSS.

Power and Water considered LRMC estimation is an imprecise science based on assumptions that may not always reflect reality.[87] We agree with this sentiment, particularly at this stage of tariff reform, where the industry as a whole is exploring optimal ways to estimate LRMC (see appendix C for further discussion). We therefore consider it is reasonable for Power and Water to use appropriate reference points when estimating LRMC, and then translating such estimates into tariffs.

85 Power and Water, *02.1 Tariff structure statement - Public*, 16 March 2018, pp. 10 and 17.

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

87 Power and Water, *Response to information request 022 - Tariff structure statement - LRMC - Public*, 29 June 2018, p. 1.

We consider the Northern Territory Utilities Commission's LRMC estimates from the 2014–19 regulatory control period is an appropriate reference point. These used the average incremental cost approach using expenditure and demand forecasts for Power and Water's network.

Importantly, these estimates informed the tariff setting process during the 2014–19 regulatory control period. In using these estimates as a reference point, Power and Water is minimising the impact on its customers by ensuring annual movements of the cost reflective components of its tariffs are not excessive.[88]

However, we caution against using the LRMC estimates of other distributors as reference points. The LRMC is intended to signal a network's future costs of changes in demand. Such costs will necessarily depend on the unique circumstance of each business—in particular, the trajectory of forecast demand and its effects on congestion at different levels of the network. These ultimately affect future costs differently for each network.

Forecast horizon

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

Power and Water used a forecast horizon of 19 years to derive its LRMC estimate using the average incremental cost approach. This is above the minimum10 year forecast horizon that we consider adequately captures the 'long run' (see appendix C).

Incorporation of repex into LRMC

We consider Power and Water's proposed approach for incorporating replacement capex in its LRMC estimates contributes to compliance with the distribution pricing principles and to the achievement of the network pricing objective.

Power and Water included 5 per cent of their annual repex forecast in their LRMC calculations. Specifically, they included 5 per cent of their annual repex forecast for all asset types.[89]

We consider Power and Water's approach to incorporating repex into LRMC calculations is very high level. Power and Water acknowledged it can improve its approach because different asset types affect marginal costs differently, and this impact would likely change over the forecast period. Power and Water flagged it is willing to discuss how it can develop this aspect of its LRMC estimation method.[90]

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

[89] Power and Water, *Response to information request 022 - Tariff structure statement - LRMC - Public*, 29 June 2018, p. 4.

[90] Power and Water, *Response to information request 022 - Tariff structure statement - LRMC - Public*, 29 June 2018, p. 4.

Given this is their first TSS, we consider Power and Water's approach is appropriate because:

- it is already 'ahead of the curve' by just including repex in their LRMC calculations. Other distributors did not include repex in the first TSS round
- as we described above, Power and Water did not directly rely on the LRMC estimates from their average incremental cost approach to derive their tariff levels.

However, we encourage Power and Water to consider the inclusion of repex in LRMC as an area for exploration and improvement in its next tariff structure statement. We discuss this further in appendix C.

18.4.4.2 Approach to setting tariffs and residual cost recovery

We consider the proposed tariff structure statement does not adequately describe the approach Power and Water will use to setting prices in each pricing proposal over the 2019–24 regulatory control period.[91]

In particular, we require Power and Water to describe in greater detail its proposed approach to allocating residual costs between customers and within the different charging parameters of each tariff.

Reflecting LRMC in tariffs

As we discussed in section 18.4.4.1, Power and Water based its proposed demand charges on LRMC estimates that it derived by comparing various sources.[92] Power and Water exercised judgement to derive these LRMC estimates, with the impact on consumers appearing to be a principal consideration.[93]

We encourage Power and Water to investigate setting its demand charges at levels closer to the LRMC estimates it derived using the average incremental cost approach (see Table 18.4).

As we discuss in the next section, Power and Water stated it intended to re-balance tariffs towards non-residential customers, who have historically paid less than the costs they contribute to the network. Setting demand charges closer to the LRMC estimates from the average incremental cost approach could be one avenue for Power and Water to achieve this.

This particularly applies to LV customers who consume more than 750 MWh per annum and all HV customers. As we discuss in section 18.4.5, Power and Water is significantly shortening the peak charging window for such customers (which we

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

92 One of these sources included the LRMC estimates it derived using the average incremental cost approach.

93 NER, cl. 6.18.5(h); Power and Water, *Response to information request 022 - Tariff structure statement - LRMC - Public*, 29 June 2018, pp. 2–3.

consider is reasonable). This could provide such customers greater scope to mitigate the impact of higher demand charges through their usage decisions.[94]

Approach to setting tariffs and residual cost recovery

We require Power and Water to describe in greater detail its proposed approach to allocating residual costs between customers and within the different charging parameters of each tariff.

Power and Water provided analysis that its proposed tariff levels would result in bill reductions.[95] In its submission, Jacana Energy welcomed Power and Water's proposed modest bill reductions for the majority of its customers in the 2019–24 regulatory control period.[96]

However, we consider Power and Water should more clearly set out its approach to setting tariffs as the rules require.[97] This would provide certainty to stakeholders how prices would likely move year-on-year should circumstances require departure from the indicative price schedule.[98] We consider Power and Water's description of its approach to setting tariffs is just too high level and would not provide certainty to stakeholders regarding annual price movements.[99]

Further, Power and Water previously indicated the revenues it recovers from residential customers exceed the cost to service them.[100] Power and Water stated it will rebalance tariffs to better align residential and large non-residential revenue shares with the corresponding allocated cost shares.[101]

However, there is inconsistency between this stated aim and the revenue and price movements in Power and Water's proposed tariff structure statement and indicative price schedule.

The Panel's analysis of Power and Water's tariff re-balancing revealed residential tariffs still recover 49 per cent of standard control services revenue throughout the 2019–24 regulatory control period.[102] Power and Water's indicative price schedule

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

95 Power and Water, *02.1 Tariff structure statement - Public*, 16 March 2018, pp. 31–33.

96 Jacana Energy, *Power and Water distribution determination*, 16 May 2018, p. 1.

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

98 Such circumstances may include operation of the unders and overs mechanism (see attachment 14), cost pass throughs, and variations between revenues in Power and Water's proposal and our final decision.

99 Power and Water, *02.1 Tariff structure statement - Public*, 16 March 2018, pp. 27–31; Power and Water, *02.2 - Tariff Structure Statement Overview - PUBLIC*, 16 March 2018, pp. 8–11.

100 Power and Water, *02.1 Tariff structure statement - Public*, 16 March 2018, p. 30; Newgate Research, *Power And Water's Future Service Delivery: Customer Deliberative Forums Final Research Report*, October 2017, slide 34.

101 Power and Water, *02.1 Tariff structure statement - Public*, 16 March 2018, p. 27.

102 CCP13, *Submission: Issues paper: Power and Water Corporation (PWC) electricity network revenue proposal 2019–24*, 16 May 2018, p. 42.
Further AER analysis suggests the proportion of revenue Power and Water would derive from residential customers rises to approximately 55 per cent during the 2019–24 regulatory control period (see Figure 18.17).

appears to reflect this pattern, in which the each tariff is escalated by the same factors in each year of the 2019–24 regulatory control period.[103]

Power and Water stated it applied 2019–20 revenue proportions to all years in the Reset Regulatory Information Notice and do not reflect its intended rebalancing for the 2019–24 regulatory control period.[104]

Power and Water further stated it would continue its tariff re-balancing throughout the 2019–24 regulatory control period if the required re-balancing is not completed by 2020, given our final determination.[105]

However, it does not appear that Power and Water's proposed tariff structure statement and indicative price schedule achieve any re-balancing of revenues away from residential customers in the first or subsequent years of the 2019–24 regulatory control period. As noted above, revenues from residential customers contribute 49 per cent of standard control services revenue in the 2019–20 regulatory year. This is still significantly above the costs they contribute to the network.[106]

Tariff structure statements are intended to provide greater certainty to stakeholders regarding tariff levels within a regulatory control period, among other things.[107] We consider Power and Water should set out in its revised proposal a clearer strategy for re-balancing tariffs to ensure the revenue shares from residential and non-residential customers reflect the costs they impose on the network.[108] We do not consider it is appropriate to achieve this re-balancing purely during the annual pricing proposal process without reference to an explicit strategy set out in the tariff structure statement.[109]

In its revised proposal, Power and Water may state an aim to re-balance tariffs such that the revenue share between residential and non-residential moves closer to the cost share. The revised proposal may aim to achieve a specific percentage allocation of revenue between residential and non-residential customers by the 2023–24 regulatory year (with percentage targets for each year to transition to this end point). The revised proposal can then describe the method and principles it will use to set the levels of individual tariffs and tariff components to achieve these revenue percentages.

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103 After the 2019–20 regulatory year, Power and Water derived its indicative price schedule by escalating each tariff component by CPI and the X factor. See Power and Water, *12.20 - Proposal Tables and Charts - Public*, 16 March 2018, 'TSS'!.

104 Power and Water, *Response to information request 033 - Unmetered tariffs, cross subsidies and individually calculated tariffs*, 31 July 2018, p. 4.

105 Power and Water, *Response to information request 033 - Unmetered tariffs, cross subsidies and individually calculated tariffs*, 31 July 2018, p. 4.

106 Power and Water, *12.3 - SCS Pricing Model - Public*, 16 March 2018, '3.1 Revenue'!; Power and Water, *11.11CP - Regulatory Determination Workbooks - Consolidated - Public*, 16 March 2018, 'Output_Cost_of_Supply'!.

107 We discuss the role and purpose of TSS in the introduction to this attachment and in section 18.3.

108 NER, cl. 6.18.1A(5).

109 NER, cl. 6.18.1A(a)(5). We acknowledge some departure from the indicative price schedule would be required during the 2019–24 regulatory control period due, for example, to the operation of the unders and overs mechanism of the revenue cap control mechanism (see attachment 14 of this draft decision for more detail).

This could include a principle to allocate more residual costs to the fixed charge of the large customer tariffs, depending on annual revenue movements. As discussed earlier, Power and Water may also move the demand charges of its large customers closer to the LRMC estimate from the average incremental cost approach.

As we discussed in sections 18.4.2.1 and 18.4.3, we also request that Power and Water further explore the tariff levels it has set for its excess kVAr charges. It is unclear at this stage whether the levels of these charges in the indicative price schedule provide incentives to improve poor power factors (the stated aim of the new charges) or that they are reflective of costs associated with poor power factor. For example Power and Water has provided no modelling to show that the additional costs imposed by customers with poor power factors is reflective of the indicative prices proposed.

It appears the primary purpose of the excess kVAr charge for the 2019–24 regulatory control period would be residual cost recovery rather than incentivising customers to improve poor power factors. We consider this is acceptable to some extent in a transition period. However, we consider Power and Water should set out a clear strategy in its revised proposal such that the excess kVAr charge is a cost reflective tariff. If confirmed, it will send appropriate signals for customers to correct power factors. That is, customers respond to the cost reflective tariff. Otherwise, the excess kVAr charge would simply add extra administration costs (for Power and Water and customers) for no real benefits.

Further, Power and Water indicated the technical requirements regarding power factors are included in clause 3.6.7 of the Network Technical Code and Network Planning Criteria.[110] However, we understand the primary document that imposes power factor obligations on customers is Power and Water's Service Rules.[111] We require Power and Water to clarify the technical requirement applicable to the connection of customer installations for the application of the excess kVAr charge in its revised proposal.

Power and Water can also provide further certainty by explicitly stating tariff levels where appropriate. A prime example would be a statement in the revised proposal to the effect of 'all demand charges will be set to $0/kVA per month throughout the 2019–24 regulatory control period'. While this was implied in the proposed tariff structure statement, such an explicit statement would remove any doubt, particularly if Power and Water adopts the "two document" approach (see section 18.4.6).[112]

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[110] Power and Water, *Response to information request 040 - Tariff structure statement - Excess kVAr charge - Public*, 6 September 2018, p. 4.

[111] Power and Water, *NP 007 Service Rules*, 1 August 2018, p. 15.

[112] By setting the off peak demand charge to zero in the indicative price schedule, Power and Water can still arguably set it to non-zero values during the 2019–24 regulatory control period in the absence of such an absolute statement.

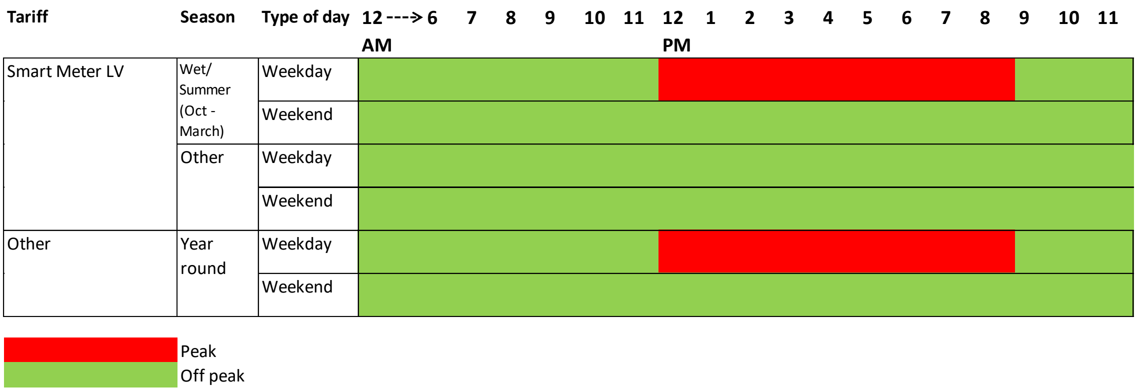
18.4.5 Charging windows

We are satisfied that Power and Water's proposed charging windows contribute to compliance with the distribution pricing principles and to the achievement of the network pricing objective.

Power and Water proposed a peak charging window from 12PM to 9PM on weekdays, including public holidays. Power and Water stated this reflects the peak system load profile.[113] Power and Water also proposed to apply seasonality to customers on the 'Smart Meter' tariff for customers on the LV network in which the peak charging window applies only during the wet season (1 October to 31 March).[114] Power and Water proposed off peak charging windows for all other times.

Figure 18.3 summarises Power and Water's proposed charging windows for the 2019–24 regulatory control period.

Figure 18.3 Power and Water's proposed charging windows



Source: Power and Water, 02.2 - Tariff Structure Statement Overview - PUBLIC, 16 March 2018, p. 9.

Power and Water's proposed charging windows is more complex than those in the 2014–19 regulatory control period, where the peak period applied from 6AM to 6PM year-round for all days. All other times in the 2014–19 regulatory control period were off peak (see Figure 18.4).

However, we are satisfied Power and Water's proposed charging windows achieve a reasonable balance between signalling times of network congestion and having regard to customer impact.[115]

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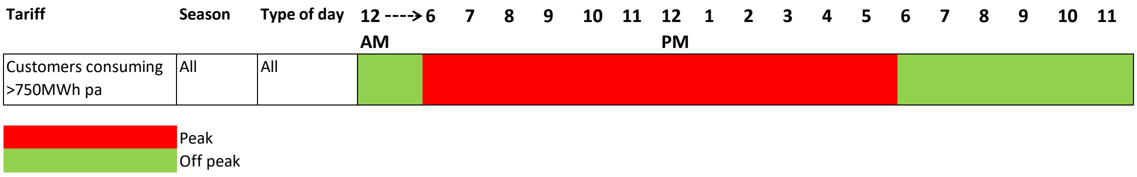
[113] Power and Water, *02.2 - Tariff Structure Statement Overview - PUBLIC*, 16 March 2018, p. 10.

[114] Power and Water, *02.2 - Tariff Structure Statement Overview - PUBLIC*, 16 March 2018, p. 13.

[115] NER, cll. 6.18.5(f)(2), (g)(1), and (h).

Figure 18.4 Power and Water's charging windows in the 2014–19 regulatory control period

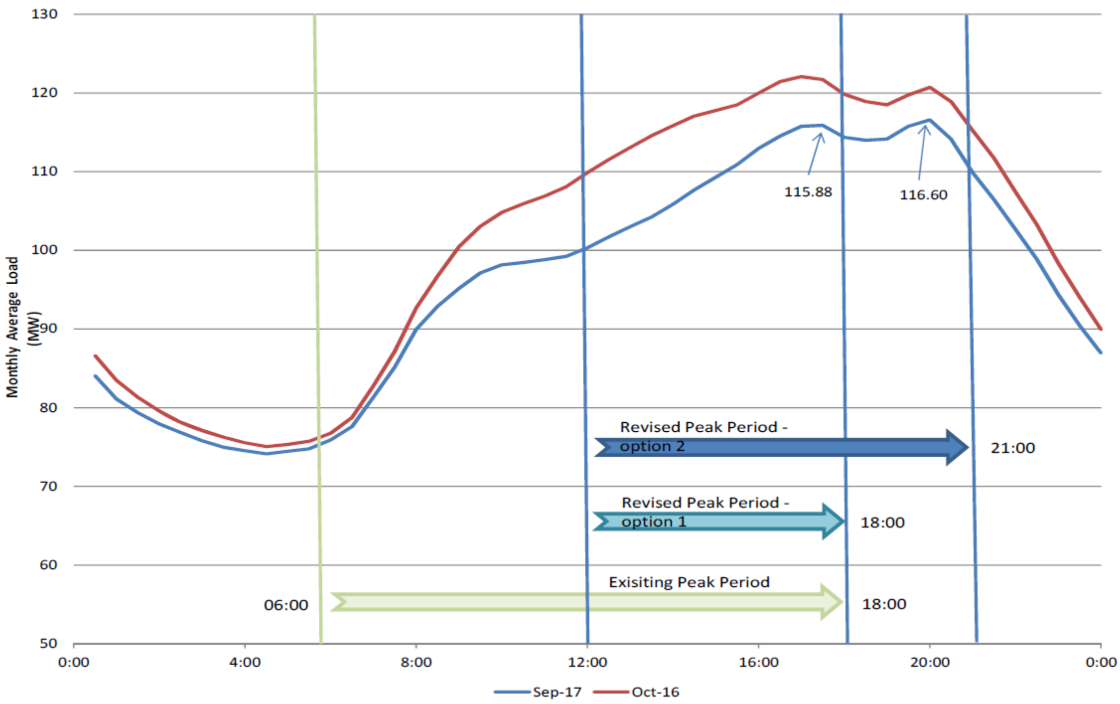


Source: Power and Water, *2018–19 Electricity Network Tariffs and Charges Network Price Determination Version*, June 2018, pp. 6-7.

Note: These charging windows applied only to Power and Water's large customers in the 2014–19 regulatory control period.

We consider the proposed charging windows in Figure 18.3 better reflect the potential timing of congestion on the network compared to the current period's charging windows. Figure 18.5 indicates Power and Water's network is developing a 'double peak' in the evening period.

Figure 18.5 Setting peak and off-peak periods



Source: Power and Water, *02.1 Tariff structure statement - Public*, 16 March 2018, p. 24.

Power and Water stated it consulted on options 1 and 2 in Figure 18.5 when it was developing its proposed tariff structure statement. We noted to Power and Water during our consultation for this draft decision that option 1 would have been better presented if it was later in the day (for example, 15:00 to 21:00). This time better coincides with the peak periods presented in Figure 18.5. We also asked if Power and Water is open to amending its peak charging window to such a time.[116]

Power and Water acknowledged that a 15:00 to 21:00 option would have been useful to discuss with stakeholders. This does however present some risk given the underlying load (excluding the impact of PV) has a strong afternoon peak, representing when air-conditioning load it is at its greatest.[117]

Power and Water also acknowledged a shorter window such as the 15:00 to 21:00 option could provide stronger signals of network congestion. However, Power and Water considers applying it in the 2019–24 regulatory control period could lead to bill shock as it would entail higher prices at peak times.

We note Power and Water has already made significant reductions to its peak charging windows compared to the 2014–19 regulatory control period (as Figure 18.3 and Figure 18.4 show). We agree with Power and Water that further reducing the number of peak period hours in the 2019–24 regulatory control period would necessitate further rises in the peak charge, which could have adverse bill impacts.

We also asked Power and Water why it proposed to apply seasonal peak windows only to customers on the Smart Meter tariff on the LV network, but year-round peak windows for other customers on demand tariffs.

We consider Power and Water's proposal to apply seasonal charging windows to Smart Meter tariff customers on the LV network only is reasonable. These customers are protected by the Electricity Pricing Order and changes in network tariffs due to the transition to seasonal charges will not directly affect their retail bills. Power and Water also provided analysis indicating that small customers will typically face lower bills under the proposed tariff structure statement (and considering the assumed revenue path in its regulatory proposal for 2019–24).[118]

Large customers, on the other hand, are not protected by the Electricity Pricing Order, so retail tariffs are more likely to reflect changes to network tariffs in the proposed tariff structure statement.

Power and Water noted the customers who face year-round peak windows under its proposed tariff structure statement are often large customers. Power and Water provided evidence showing such customers, individually, can contribute a significant proportion of the congestion to relevant network assets. In addition, such customers can have demand levels that are quite close to levels during the wet/summer season at

[116] AER, *Information request 014 - Tariff structure statement*, 16 May 2018, pp. 1–2.

[117] Power and Water, *Response to information request 014 - Tariff structure statement - Public version (Confidential material redacted)*, 23 May 2018, p. 3.

[118] Power and Water, *02.1 Tariff structure statement - Public*, 16 March 2018, pp. 31–33.

other times of the year. Hence, such customers may contribute to network congestion even outside the wet/summer season.[119]

Power and Water acknowledged seasonal charging windows can also provide stronger signals for large customers to reduce energy at peak times. Power and Water signalled it could gradually transition to seasonal charging windows in future periods, but proposed to apply the peak window year round to mitigate adverse customer impacts. In particular, Power and Water stated:[120]

- the Electricity Pricing Order does not apply to large customers. Seasonal peak charges could lead to significant variation in electricity bills for such customers between seasons, with consequent cash flow impact
- the wet season corresponds to a decline in economic activity, with many businesses choosing to reduce hours of operation, or not operate at all. Power and Water considers a strong peak signal in the wet season may lead to a further reduction in economic activity during these periods
- an incremental transition to peak charges will help businesses change their behaviour over time, without bill shocks. The proposed tariff strategy already represents a significant change with the move from declining block tariffs and the removal of an off-peak demand charge (see section 18.4.3).

18.4.6 Statement structure and completeness

Power and Water must include the following elements within its tariff structure statement:

- the tariff classes into which its customers will be grouped
- the policies and procedures Power and Water 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 Power and Water will take in setting each tariff in each annual pricing proposal during the regulatory control period.[121]

Power and Water 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

[119] Power and Water, *Response to information request 014 - Tariff structure statement*, 23 May 2018, pp. 2–3. CONFIDENTIAL.

[120] Power and Water, *Response to information request 014 - Tariff structure statement - Public version (Confidential material redacted)*, 23 May 2018, p. 1.

[121] NER, cl.6.18.1A(a).

regulatory control period, the indicative price levels determined in accordance with the tariff structure statement.[122]

Power and Water tariff statement proposal largely incorporates each of the elements required under the rules.

We do however consider that Power and Water requires more information on the following aspects before we can be satisfied that they contribute to compliance with the distribution pricing principles and to the achievement of the network pricing objective:

- unmetered tariffs, particularly with regard the assignment policy (see section 18.4.2.2 for further discussion)
- individually calculated tariffs such as criteria for assigning customers to such tariffs, and the method for determining structures and price levels (see section 18.4.3 for further discussion)
- the approach it will use to set prices in each pricing proposal over the 2019–24 regulatory control period (see section 18.4.4.2 for further discussion).[123]

Tariff structure statement form

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

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

Power and Water's tariff structure statement currently relies on a single tariff structure statement document which combines the NER requirements with broader explanatory material regarding its overall tariff strategy and reasoning.[124]

While not strictly a requirement, we request Power and Water adopt a “two document” approach to structuring the tariff structure statement as part of its revised proposal. The first document only including the elements of the tariff structure statement listed in the NER as the constituent elements with a further separate document contains Power and Water's reasons for each of these proposed elements (i.e. an explanatory document).

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

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

[123] NER, cl 6.18.1A(a)(5).

[124] Power and Water, *2.1 Tariff Structure Statement - Public*, 16 March 2018.

- it makes it much easier to identify if the tariff structure statement is complete and includes each of the required elements[125]
- if we do not approve an element of a revised proposal, it makes it much easier to revise
- it provides a shorter, clearer and more concise document for application during the regulatory control period. It also makes it easier for stakeholders to understand the tariff structures which apply over the regulatory control period. Further, this makes the AER's task of assessing compliance of annual pricing proposals against the tariff structure statement easier.

These two documents would be in addition to the tariff structure statement overview document and indicative pricing schedule, both of which Power and Water provided.[126] We consider that both Endeavour Energy and SA Power Networks proposals from the first round of tariff structure statements provide good examples to follow.[127]

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125 As listed in NER cl. 6.18.1A.

126 Power and Water, *2.2 Tariff Structure Statement Overview - Public*, 16 March 2018.

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

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

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

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

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

We must take into account these unique environmental conditions when assessing whether a tariff structure statement proposal complies with the distribution pricing principles set out in Chapter 6 of the NER.[128]

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

Key Characteristics of the Northern Territory Electricity Network

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[128] NER cl. 6.18.1A

Power and Water is a government-owned corporation that provides electricity network services in the Northern Territory. Power and Water also owns and operates large water storage dams as well as providing retail drinking water and wastewater treatment services.[129]

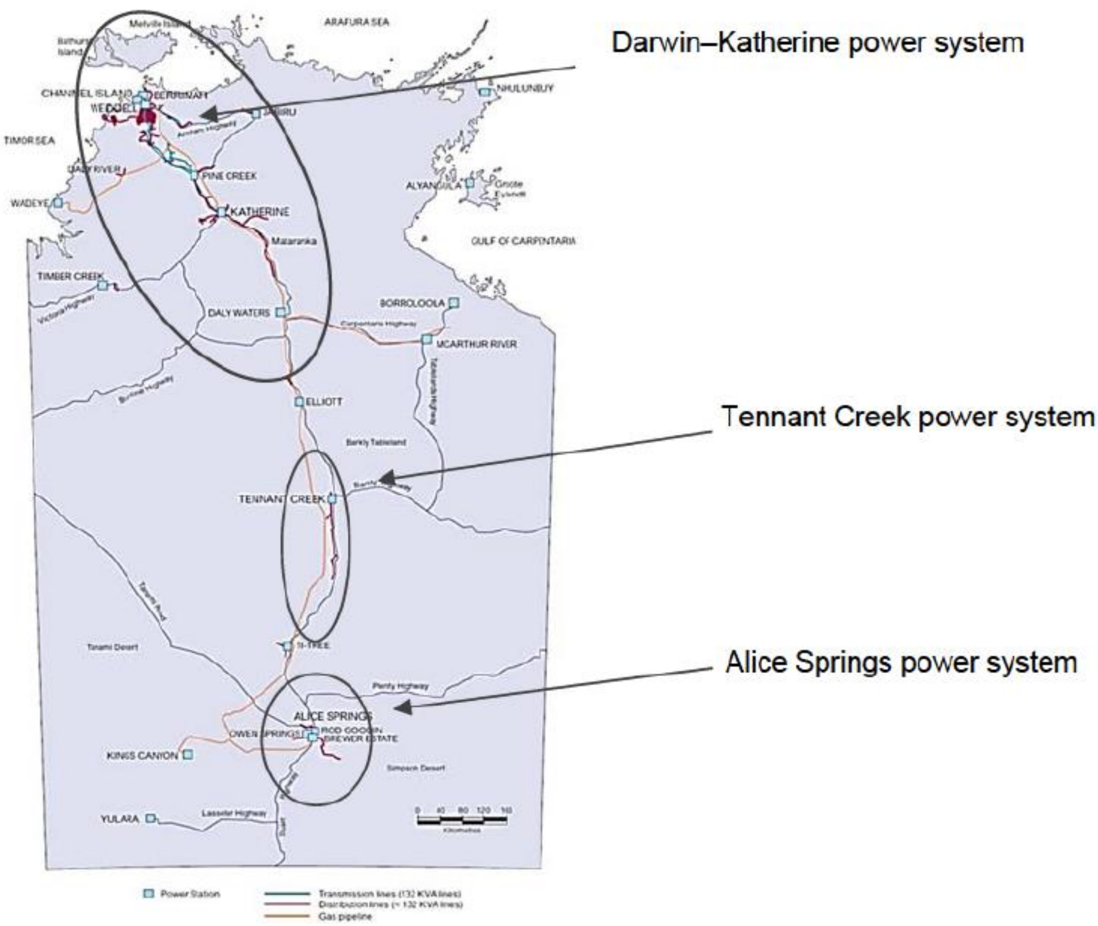
Power and Water's electricity network area stretches from the tropical savannah in the far north to the deserts of Central Australia. While Power and Water has one of the largest network area of any distributor in Australia, it provides electricity network services to a small and geographically diverse population.

In contrast to distributors in NEM, the electricity transmission assets owned and operated in the Northern Territory are not costed or priced from a transmission network's perspective. As a result, Power and Water's network use of system tariffs do not comprise a Transmission Use of System (TUOS) component.

Power and Water operates three major electricity systems in the Northern Territory, (see Figure 18.6).

[129] Power and Water also supplies electricity, drinking water and wastewater treatment services to remote towns and communities under the Indigenous Essential Service agreement with the Northern Territory Government.

Figure 18.6 Power and Water's electricity network



Source: Power and Water, *04.4 AEMO PWC Maximum Demand, Energy, Consumption and Connection Forecasts*, September 2017 p. 4.

Maximum Demand Growth

Given the mild winter temperatures in the Northern Territory, peak maximum demand in Power and Water’s electricity network occurs in the extended summer period between 1 October and 31 March of each year.

Power and Water commissioned the Australian Energy Market Operator (AEMO) to produce independent demand and volume forecasts for the 2019–24 regulatory control period.

AEMO is forecasting a decline in overall-system wide maximum demand in Power and Water's electricity network over the 2019–24 regulatory control period. This decline in demand is expected in spite of forecast growth in new customers over the medium term.

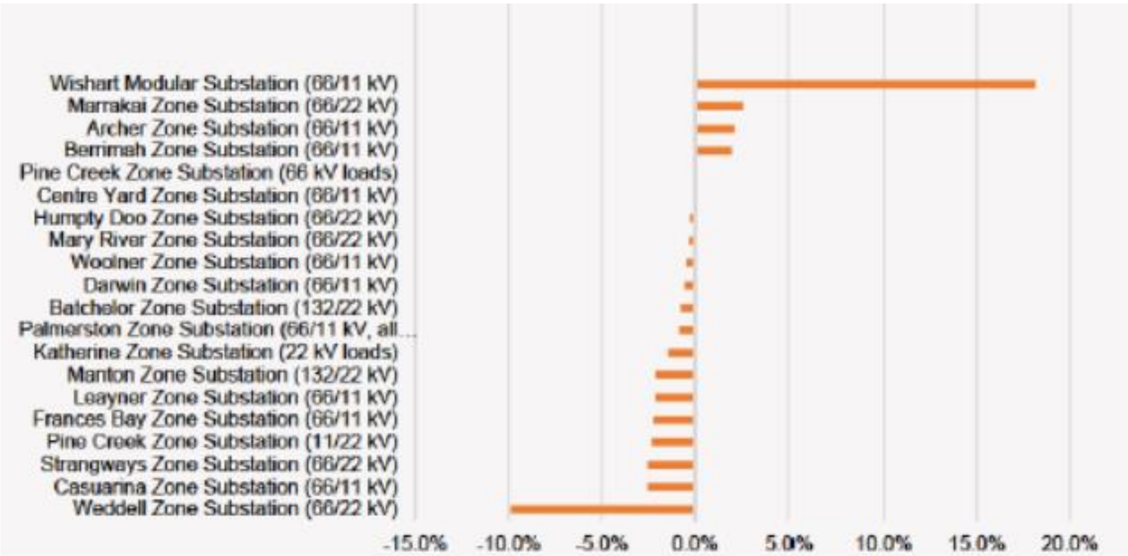
Figure 18.7 provides a comparison of the medium term forecast of peak demand and number of customers in Power and Water’s network area.

Figure 18.7 Forecast peak demand and customer numbers

Source: Power and Water, *02.1 - Tariff structure statement - Public*, 16 March 2018, p. 10.

While peak demand is forecast to decline at an overall system level, it is important to note some areas of Power and Water's network are forecast to experience growing peak demand over the medium term. Figure 18.8 demonstrates this in the Darwin-Katherine area.

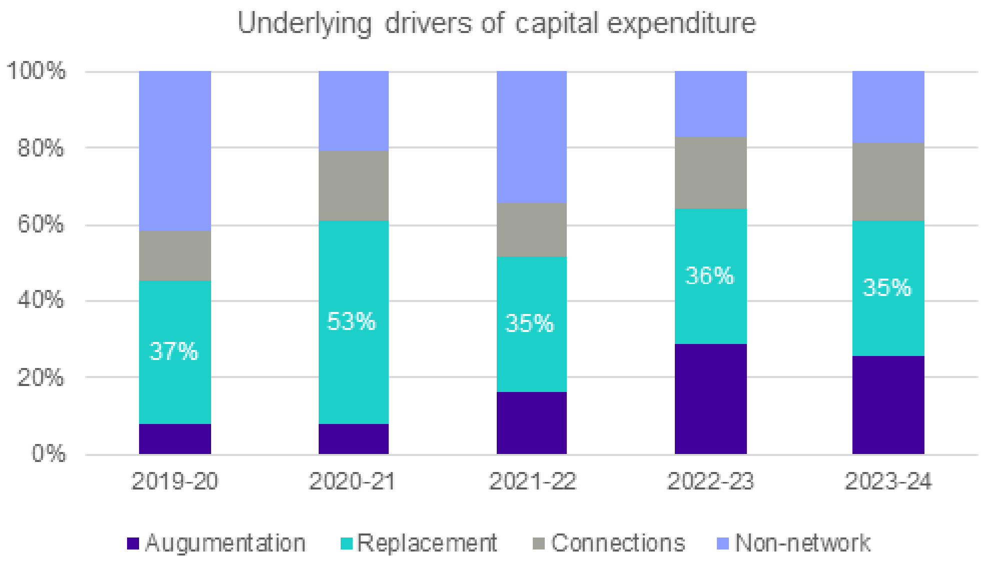
Figure 18.8 Forecast peak demand growth by substation – Darwin-Katherine area



Source: Power and Water, *04.4 AEMO PWC Maximum Demand, Energy, Consumption and Connection Forecasts*, September 2017, p. 9.

As with other jurisdictions, the forecast decline in peak demand is expected to result in growth-related capital expenditure no longer being a major driver of Power and Water's network costs over the medium term (see Figure 18.9).

Figure 18.9 Composition of Power and Water's capex forecast



Source: AER analysis.

It is relevant to note that the relatively high importance of replacement capital expenditure in the cost function of most distributors in Australia, together with declining overall peak demand for electricity network capacity, has important implications for the efficient design of cost reflective network tariffs.[130]

Energy consumption

Table 18.5 shows the current AEMO medium term forecast of annual electricity consumption, that is, kWh, by NEM region.[131]

Table 18.5 Forecast electricity consumption by NEM region

	NSW	QLD	SA	TAS	VIC	NT
2018–19	66,727	51,890	11,949	10,421	42,828	1,843
2019–20	66,303	51,924	12,355	10,379	42,525	1,829
2020–21	66,101	52,039	12,259	10,347	42,514	1,829

130 We discuss the incorporation of replacement capex into long run marginal cost estimates in appendix C of this draft decision.

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

2021–22	65,976	52,067	12,184	9,932	41,555	1,830
2022–23	65,703	52,416	12,120	9,907	40,639	1,831
2023–24	65,517	52,384	12,065	9,887	39,925	1,835
2024–25	65,588	52,372	12,023	9,901	39,060	1,839
2025–26	65,715	53,833	12,005	9,986	39,309	1,844
2026–27	65,918	53,961	11,989	10,072	39,514	1,848

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

We note the following from the table above:

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

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

Table 18.6 shows that the Darwin-Katherine region is the only region within Power and Water's electricity network that is forecast to experience growth in energy consumption over the medium term.

Table 18.6 Forecast electricity consumption by region

Year	Darwin-Katherine	Alice Springs	Tennant Creek	Total
2019	1,591	214	37	1,843
2020	1,580	212	37	1,829
2021	1,582	210	38	1,829
2022	1,584	208	38	1,830
2023	1,588	206	38	1,831
2024	1,593	205	38	1,835

Source: Power and Water, *04.4 AEMO PWC Maximum Demand, Energy, Consumption and Connection Forecasts*, September 2017.

An important underlying driver of trends in energy consumption is the adoption of Distributed Energy Resources. Table 18.7 provides a regional comparison of the cumulative installation of Solar Photo voltaic systems by state and territory over the decade to 2017 period.

Table 18.7 Solar PV system installations by jurisdiction

Year	ACT	NSW	NT	QLD	SA	TAS	VIC
2008	278	2,890	88	3,087	3,456	161	2,036
2009	803	14,008	215	18,283	8,569	1,452	8,429
2010	2,323	69,988	637	48,697	16,705	1,889	35,676
2011	6,860	80,272	401	95,303	63,553	2,475	60,214
2012	1,522	53,961	513	130,252	41,851	6,364	66,204
2013	2,411	33,998	1,024	71,197	29,187	7,658	33,332
2014	1,225	37,210	1,026	57,748	15,166	4,207	40,061
2015	1,066	33,477	1,197	39,507	12,081	2,020	31,343
2016	999	29,441	1,745	34,389	12,594	2,486	26,697
2017	1,340	32,871	1,532	37,467	11,926	1,849	23,452

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

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

AEMO is forecasting solar PV installed capacity to increase in Power and Water's network area over the medium term, particularly in the Darwin-Katherine region (see Table 18.8).

Table 18.8 Forecast Solar PV installed capacity (MW) by region

Year	Darwin-Katherine	Alice Springs	Tennant Creek	Total
2019	51	14	0	65
2020	58	15	1	74
2021	64	17	1	81
2022	69	18	1	87
2023	74	19	1	94

2024	79	20	1	99
2025	83	20	1	104
2026	87	21	1	108
2027	90	22	1	112

Source: Power and Water, *04.4 AEMO PWC Maximum Demand, Energy, Consumption and Connection Forecasts*, September 2017, p. 26.

The annual electricity consumption for a representative residential customer varies markedly across the NEM, as shown in Table 18.9.[132] We consider this variation reflects a broad range of factors including differences in temperature conditions, the mix of appliances and the market penetration of gas for heating and electric cooking.

Table 18.9 Comparison of annual electricity consumption per residential customer by NEM region

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

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

We note the following from the above table:

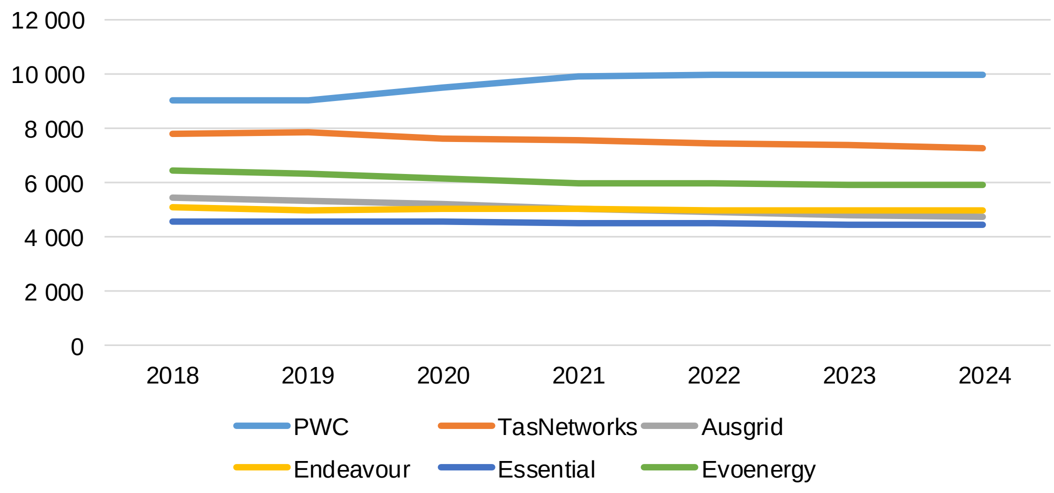
- the influence of colder temperatures have resulted in Tasmania and the Australian Capital Territory having the highest annual residential electricity consumption in Australia
- the Northern Territory has the third highest annual residential energy consumption in spite of minimal need for winter heating load

132 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

- Victoria and New South Wales have the lowest annual residential electricity consumption in Australia in part reflecting the higher penetration of gas for heating and cooking
- annual residential electricity consumption is similar in South Australia (5,000 kWh pa) and Queensland (5,240 kWh pa).

Figure 18.10 provides a comparison of the indicative energy consumption per residential customer by selected distributors over the next regulatory control period. TasNetworks and Power Water are the only distributors in the figure above that do not expect residential energy consumption per customer to decline in the next regulatory control period over the medium term.

Figure 18.10 Comparison of residential average consumption by distributor



Source: AER analysis

Note: 'PWC' refers to Power and Water in Figure 18.10.

Customer numbers

Power and Water is forecasting moderate growth in the number of total customers connected to its electricity distribution network over the next regulatory control period (see Table 18.10).

Table 18.10 Annual Customer numbers by type

	2019	2020	2021	2022	2023	2024
Residential	71,586	72,061	72,628	73,208	73,388	73,570
Business	12,834	13,011	13,220	13,433	13,640	13,849
Total	84,420	85,072	85,848	86,641	87,028	87,419

Source: Power and Water, *04.4 AEMO PWC Maximum Demand, Energy, Consumption and Connection Forecasts*, September 2017.

The forecast growth in the total number of connections is driven mainly by underlying growth in residential connections in the Darwin-Katherine region (see Table 18.11).

Table 18.11 Annual Residential Customer numbers by region

	2019	2020	2021	2022	2023	2024
Darwin-Katherine	60,028	60,485	61,016	61,556	61,756	61,957
Alice Springs	10,256	10,258	10,276	10,300	10,269	10,242
Tennant Creek	1,302	1,318	1,336	1,352	1,363	1,371

Source: Power and Water, *04.4 AEMO PWC Maximum Demand, Energy, Consumption and Connection Forecasts*, September 2017.

Table 18.12 shows that the number of business customers is forecast to increase over the next regulatory control period in all three regions of Power and Water's electricity network.

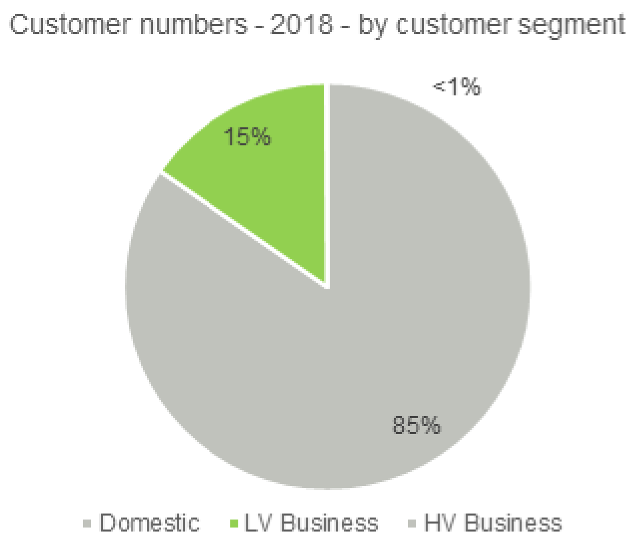
Table 18.12 Annual Business customer numbers by region

	2019	2020	2021	2022	2023	2024
Darwin-Katherine	10,571	10,734	10,921	11,112	11,298	11,485
Alice Springs	1,947	1,959	1,977	1,996	2,013	2,032
Tennant Creek	316	318	322	325	329	332

Source: Power and Water, *04.4 AEMO PWC Maximum Demand, Energy, Consumption and Connection Forecasts*, September 2017.

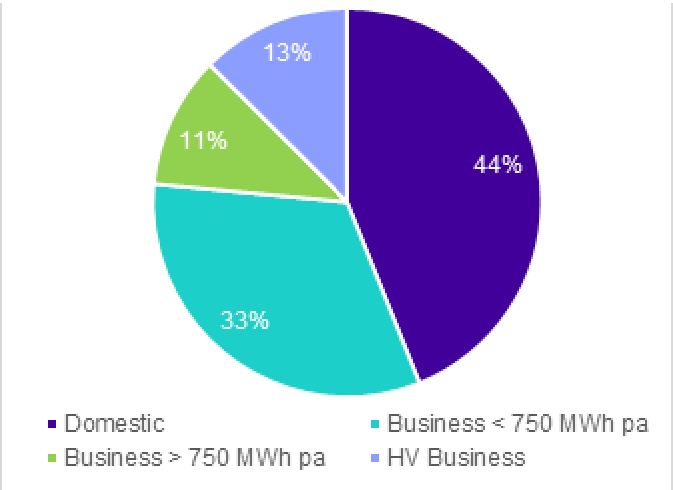
The residential and LV business segments in Power and Water's network area account for a high annual share of total energy consumption and total customers (see Figure 18.11 and Figure 18.12). While there is a small number of business customers that consume more than 750 MWh per annum in the Northern Territory, the large size of these customers means that they account for a material share of Power and Water's total energy consumption per annum, as shown in Figure 18.12.

Figure 18.11 Annual number by tariff class



Source: AER analysis.

Figure 18.12 Annual energy consumption by customer segment



Source: AER analysis.

Network costs, revenues and average network prices

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

Power and Water has proposed a reduction to their revenue requirement in the first year of the 2019–24 regulatory control period for standard control services. Power and Water then proposed modest real increases in the annual revenue requirement in the remaining four years (see Table 18.13).

Table 18.13 Power and Water proposed distribution revenue requirement

Smoothed Revenue Requirement	2018-19	2019-20	2020-21	2021-22	2022-23	2023-24
Distribution standard control revenue ($m)	177.84	165.00	174.71	184.98	195.86	207.39

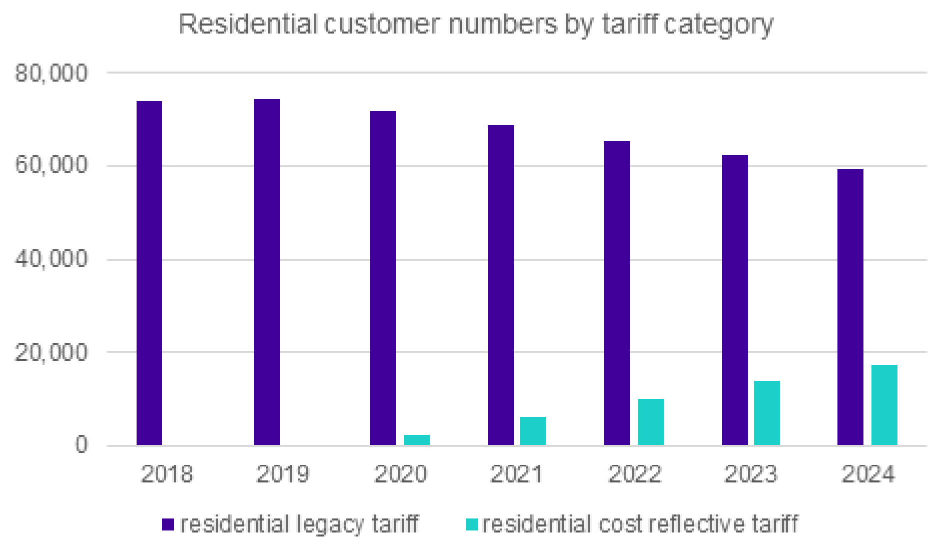
Source: Power and Water, *01.2 - Regulatory proposal - Public, 16 March 2018*, p. 127.

Interval metering penetration

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

Figure 18.13 below shows Power and Water's forecast for the number of residential customers with interval metering installed in their premise during the 2019–24 regulatory control period by cost reflective and legacy tariff groupings.

Figure 18.13 Residential customers with interval meter by tariff type



Source: AER analysis.

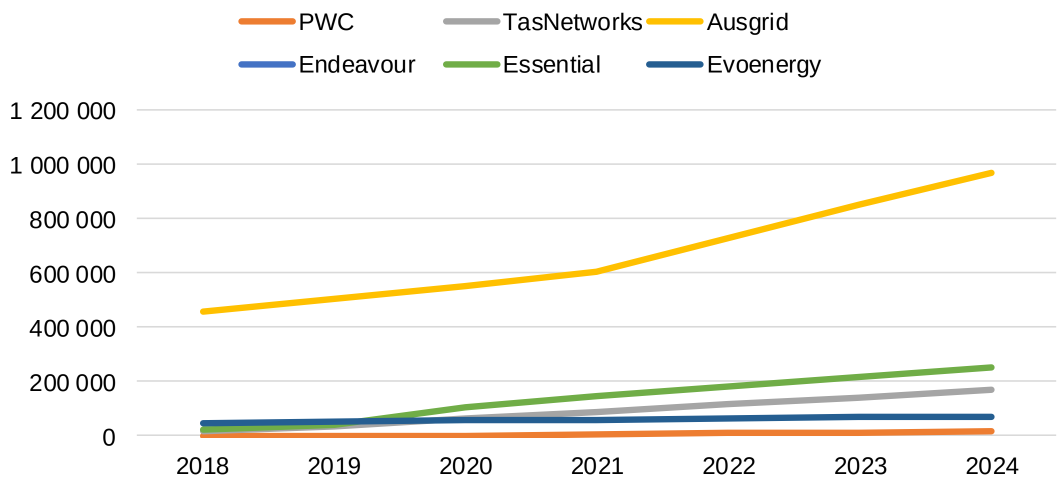
The key point from Figure 18.13 is Power and Water's proposed tariff assignment policy is expected to result in a marked increase in the number of residential customers on a network demand tariff by the end of the next regulatory control period, albeit from a low base.[133]

[133] We discuss Power and Water's proposed tariff assignment policy in section 18.4.1 of this draft decision.

It is also important to note that Power and Water does not propose to allow customers on a cost reflective demand tariff to opt-out to a flat tariff, as a consequence the number of customers on the non-cost reflective tariff is forecast to steadily decline over the next regulatory control period, mainly in line with the end of life replacement of basic accumulation metering.

The figure below compares the forecast number of interval metered customers by selected distributors 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.[134]

Figure 18.14 Historical and forecast number of interval metered customers by distributor



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

The key points from the figure above are summarised below:

- TasNetworks and Ausgrid are expected to have the highest per cent of residential customers with interval metering installed in their premise by the end of the next regulatory control period
- Evoenergy, Essential Energy and Endeavour energy are all expected to have interval metering installed in around one third of their residential customer base by the endo of the next regulatory control period
- Power and Water is expected to have the lowest penetration of interval metering in the residential customer segment with around a quarter of these customers having

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[134] 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.

interval metering by the end of the next regulatory control period. We note Power and Water are the responsible entity for metering over this period.

Overview of proposed network tariff assignment procedures

The extent that a build-up in the penetration of interval metering translates to an increase in the number of customers on more cost reflective tariffs is dependent on distributors' network tariff assignment and re-assignment policies. Table 18.14 provides a comparison of the proposed tariff assignment policies for each distributor.

Table 18.14 Comparison of tariff assignment policies – residential customers

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

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

Source: AER analysis.

We note the following key points from Table 18.14:

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

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 services (and for the purpose of supply alternative control services). Tariff classes are important because the efficiency bounds test and the side constraints are both applied at the tariff class level.

Table 18.15 provides a summary of the current tariff classes for each distributor. It is clear from this analysis that there is a considerable variation in the extent of tariff class disaggregation across distributors, particularly in respect to customers connected at the low voltage level of the electricity network.

Table 18.15 Current tariff classes by distributor

Ausgrid	Endeavour Energy	Essential Energy	TasNetworks	Evoenergy	Power and Water
	Low voltage energy	Low voltage energy	Residential	Residential	Less than 750 MWh per annum
Low voltage	Low Voltage Demand	Low voltage Demand	Small low voltage Large low voltage Uncontrolled energy Controlled energy	Commercial low voltage	More than 750 MWh per annum
High voltage	High voltage	High voltage	High voltage	High voltage	High voltage
Sub-transmission Voltage Transmission-connected	Inter-Distributor Transfer (IDT)	Sub-transmission Voltage	Individual Tariff Calculation Class		
Unmetered supply	Unmetered supply	Unmetered supply	Unmetered supply		

Source: AER analysis.

Table 18.15 shows Power and Water has a simple approach to classifying customers with relatively few tariff classes.

Network tariffs

NUOS tariffs in Australia typically comprise the following components:

- distribution use of system (DUoS) component – this component relates to the cost of providing standard control distribution services, plus an adjustment for the overs and unders account of the revenue cap control mechanism and any pass through amounts approved by the AER
- transmission use of system (TUoS) component – this component relates to the cost of providing standard control transmission services, plus an adjustment for the overs and unders account of the revenue cap control mechanism and any pass through amounts approved by the AER
- jurisdictional scheme amount component – this component only applies where a DNSP is required to contribute to a Jurisdictional scheme imposed by a state or territory government, plus an adjustment for the over/under recovery of the actual contribution amount payable.[135]

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

Importantly Power and Water's NUOS tariffs only comprise a DUOS component.

The following table provides a summary of the network tariff structures for residential and small business customers in the NEM. While all of these tariffs comprise a fixed charging parameter, the structure usage charging parameter varies considerably across tariffs.

Table 18.16 Network tariff structures by distributor

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

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

Key statistics for Network tariffs

Table 18.17 shows the number of customers and NUOS revenue for the major tariffs for residential and small business customers by selected distributors in Australia.

Table 18.17 Key statistics - current network tariffs

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

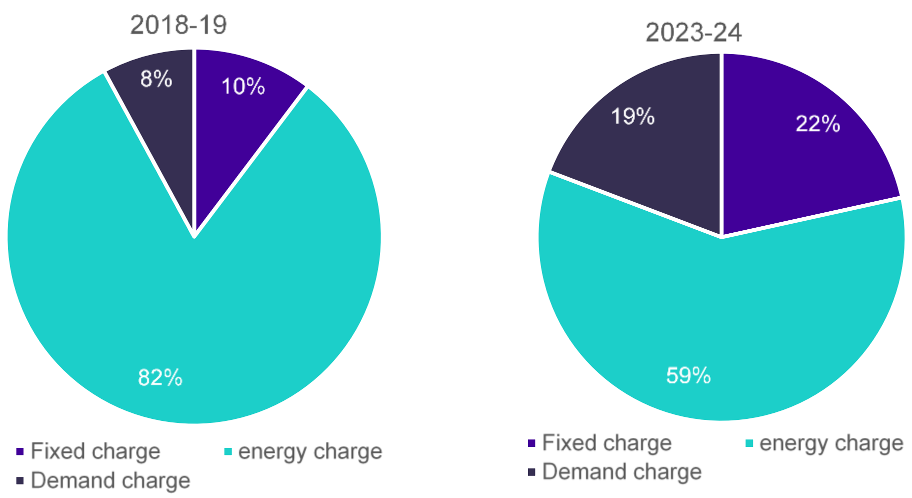
Source: AER analysis.

Power and Water network tariffs

Power and Water's NUOS tariffs are unique in an Australian context in the sense that there is no underlying component relating to the annual recovery of TUOS costs and jurisdictional scheme amounts. As a result, there is no need to separately explore Power and Water's DUOS tariffs.

Figure 18.15 shows the annual NUOS revenue share by charging parameter type for the main tariffs.

Figure 18.15 Power and Water NUOS revenue share by charging parameter – major tariffs

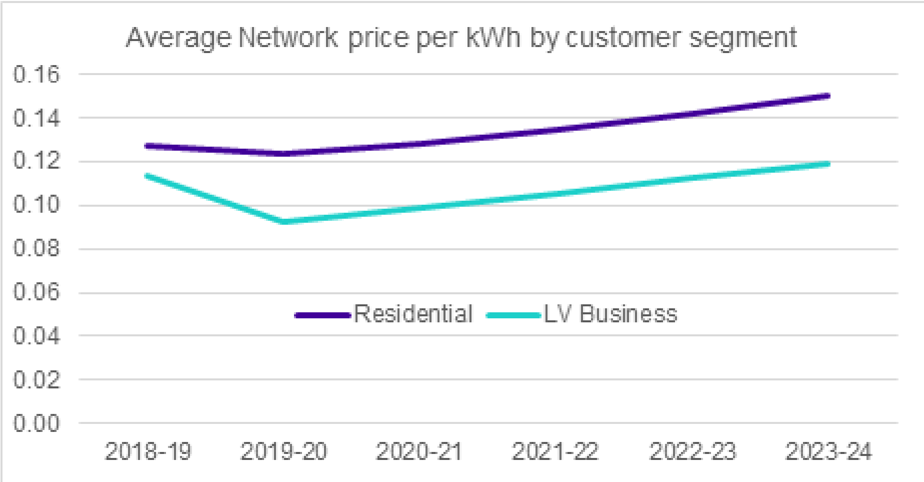


Source: AER analysis.

Figure 18.15 highlights that Power and Water proposed to make significant progress in rebalancing its network use of system tariffs in the 2019–24 regulatory control period. The substantial re-balancing of revenue away from energy consumption towards fixed charges will be achieved by a mandated increase in the penetration of demand tariffs and a proposal to increase fixed charges at a higher rate than energy consumption charges over this period.

It is relevant to note that the appropriateness of the proposed pace of network tariff reform must be assessed in the context of the customer impact principle in Chapter 6 of the NER. In this regard, we note that Power and Water proposed smoothing of its revenue requirement for the purpose of setting the proposed X factors applying under the revenue cap control mechanism is designed to reduce network prices in the first year of the next regulatory control period to create "headroom" to pursue its tariff reform objectives with minimal bill impacts on customers (see Figure 18.16).

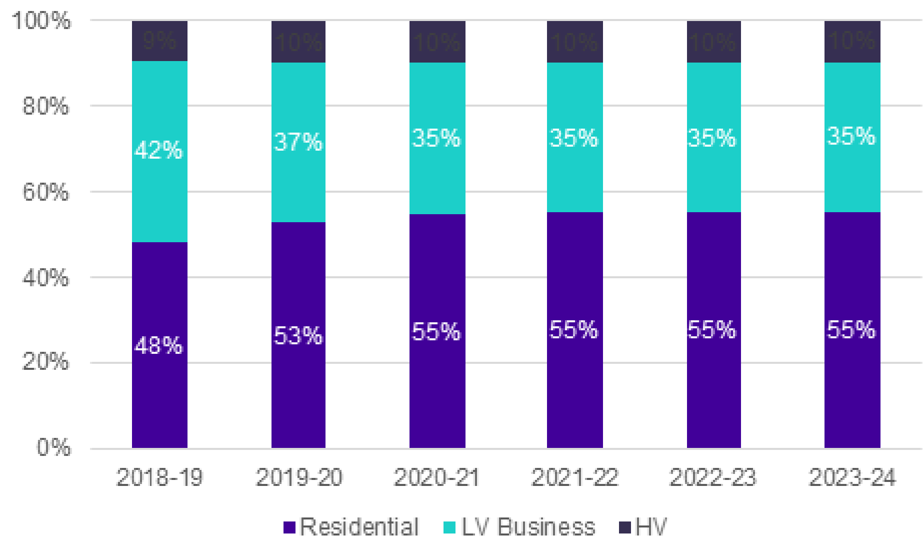
Figure 18.16 Indicative average network price movement



Source: AER analysis.

Figure 18.17 shows Power and Water is forecasting that the residential customer will account for just over half of its annual revenue entitlement in the 2019–24 regulatory control period. This level of reliance on the residential customer segment from a forecast network revenue perspective is high compared to most other distributors.

Figure 18.17 NUOS revenue share by customer segment



Source: AER analysis.

Insights into the economic efficiency implications of tariff reform proposals

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

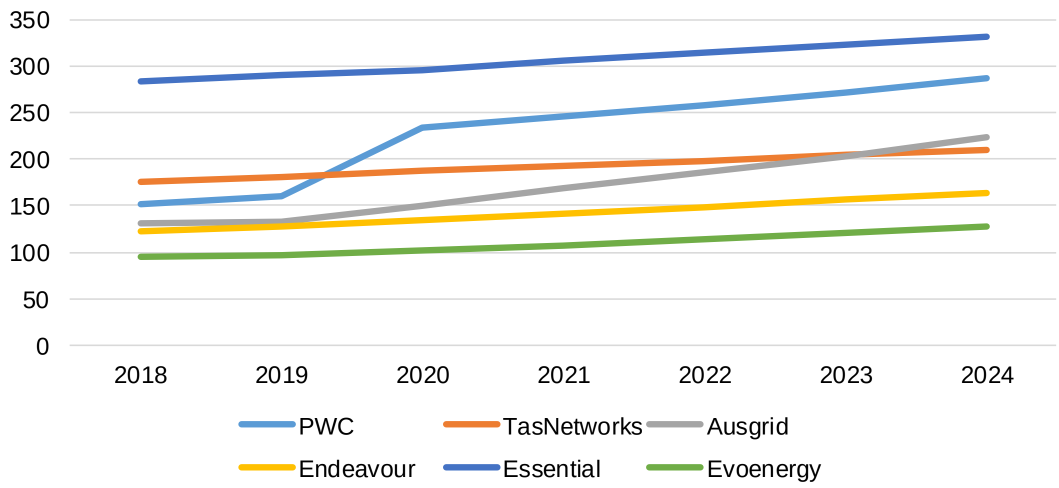
Progress towards efficient recovery of residual costs

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

The fixed charge has the potential to be an economically efficient way to recover these costs because changes in the level of the fixed charge do not typically influence the investment, network connection and consumption decisions of electricity distribution customers. Nevertheless it is important from a compliance perspective that the rate of fixed charge increases does not contravene the customer impact principle in the NER.[136]

Figure 18.18 provides insights into the extent that the distributors propose to increase the level of the fixed charge of their residential legacy tariff in the next regulatory control period.

Figure 18.18 Distributor comparison - Fixed charges residential legacy tariff ($ per annum)



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

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

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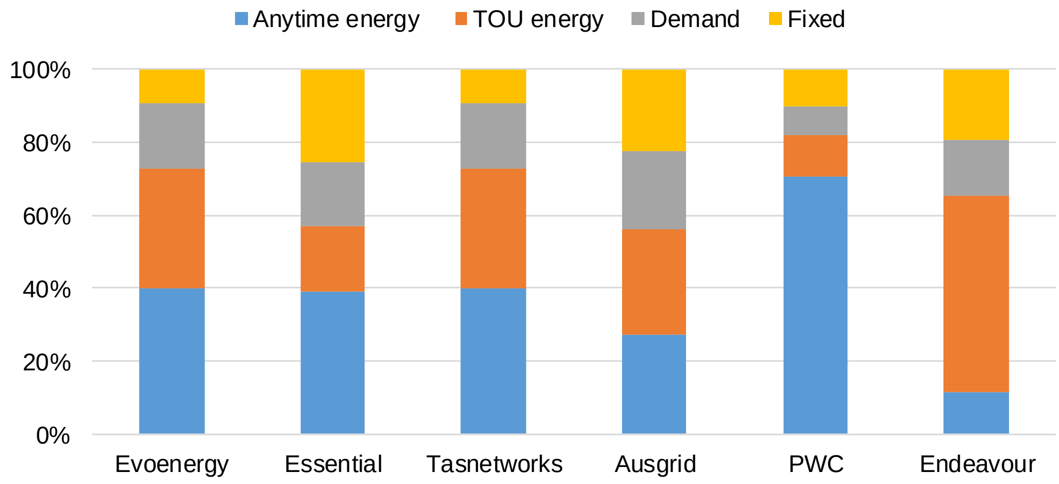
[136] NER, cl 6.18.5(h)

Figure 18.19 Distributor comparison network revenue share by charging parameter



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

Figure 18.19 above shows that the current reliance on anytime energy charges from a NUOS revenue perspective varies markedly across individual distributors.

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

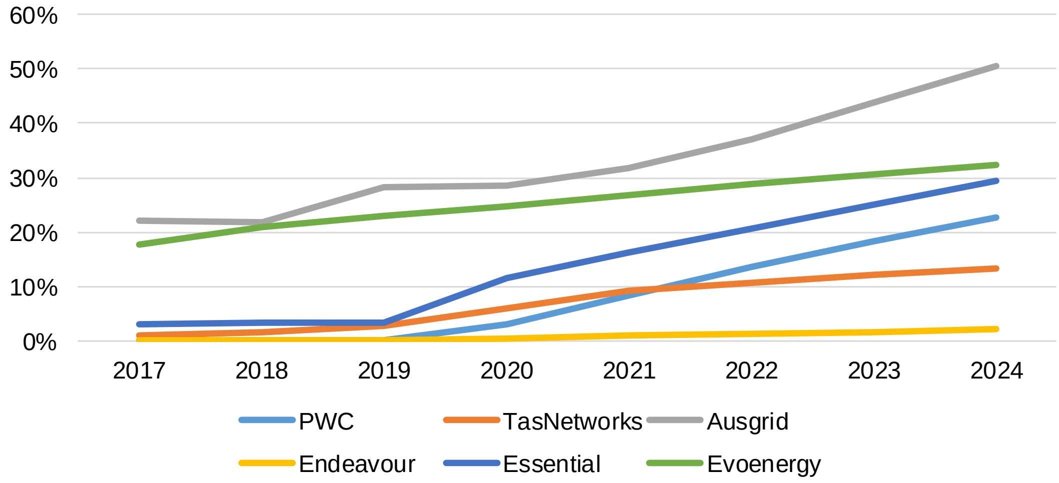
Progress towards LRMC-based pricing

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

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

Power and Water proposed to continue to mandate demand pricing for new energised connections and existing customers that have their basic accumulated meter upgraded or replaced in the residential and small business customer segment. As a result of this policy, the number of Power and Water's residential customers on a more cost reflective demand tariff will grow over the five years to 30 June 2024, as shown in Figure 18.20.

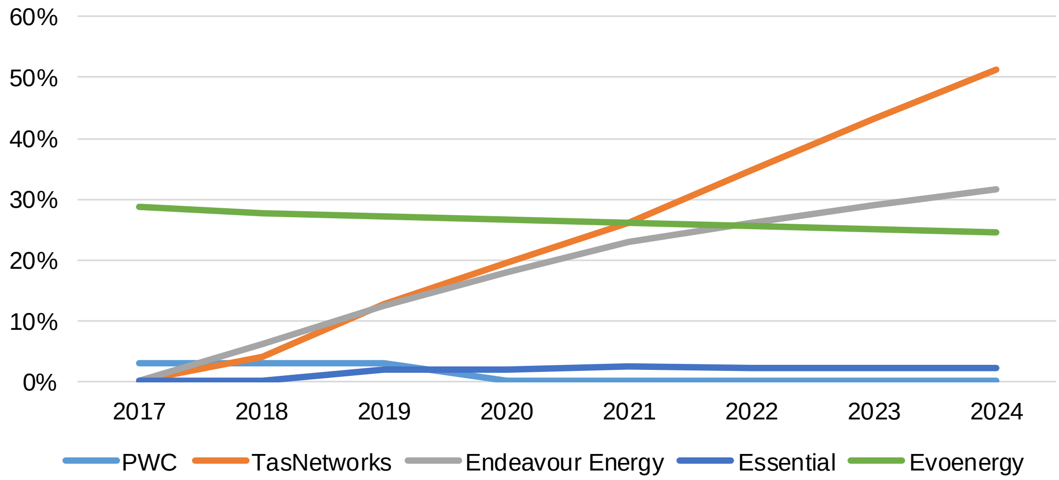
Figure 18.20 Annual penetration of cost reflective pricing in residential segment



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

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

Figure 18.21 Interval meter penetration on non-cost reflective tariff by distributor



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

Due to its proposal to prescribe customers with interval meters to demand tariffs, there will be no Power and Water customer with an interval meter on a non-cost reflective network tariff.

Retail electricity pricing in the Northern Territory

Retailers are not active in the Northern Territory market despite having introduced full retail contestability since 1 April 2010. As with Tasmania, retail price regulation and the small size of the market continue to be barriers to entering this market.

All residential and business customers in the Northern Territory have the choice of staying with the local retailer (Jacana Energy) and negotiating a market retail contract or negotiating a market retail contract with another authorised electricity retailer.

The retail electricity tariffs and charges in the Northern Territory are regulated via an Electricity Pricing Order (the Order) issued by the Northern Territory Government.[137] The Order applies to contestable customers using less than 750 MWh per annum. This encompasses all of Power and Water's 85,000 customers, except for its 200 largest customers.[138]

The Order prescribes particular tariff structures for certain customer types. It also caps the prices retailers can charge for each tariff component. The government issues a new Order annually, which regulates retail prices. Any changes to underlying network tariffs therefore do not affect Power and Water's small customers at the retail level as long as the Government has the Order in place.

This means that Power and Water's proposed network tariff reform will only directly impact the electricity retail tariffs of around 200 customers using 750 MWh per annum and above.

It is also relevant to note that the AEMC has estimated the annual difference between the residential retail tariff and the aggregate of the supply chain costs is around $161 per annum for a representative customer.[139]

Regulated Retail pricing behaviour in the NT

Jacana Energy's tariffs for small customers exactly reflect those set out in the Order. Although the Order sets out price caps (rather than mandated prices), Jacana Energy sets its retail tariff levels for small customers at exactly these price caps. This reflects Jacana Energy's dominant position in the Northern Territory electricity retail market.

A unique feature of the Order is that it does not necessarily follow the structure of the underlying network tariffs. For example, the Order includes both an anytime energy tariff and a time of use tariff for small customers. On the other hand, Power and Water only had a network anytime energy tariff during the 2014–19 regulatory control period.

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137 The Electricity Pricing Order for the 2018–19 year is available from: www.jacanaenergy.com.au/news_and_publications/publications/tariffs_and_pricing/Northern_Territory_Pricing_Order_gazette_g26.pdf

138 Power and Water, *02.1 - Tariff Structure Statement - Public*, 16 March 2018, pp. 9–10.

139 AEMC, *2017 Residential Electricity Price Trends*, p. 166.

B Tariff design and assignment policy principles

Under the NER, the objective of tariff reform is to introduce cost reflective pricing.[140] 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[141]
- contemplate whether customers are going to be able to understand the charges they are likely to see.[142]

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

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

When should tariff assignment happen?

[140] NER cl 6.18.5(a).

[141] NER cl. 6.18.5(h).

[142] NER cl. 6.18.5(i).

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

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

Tariff assignment is when, in accordance with its approved tariff structure statement, the distributor decides what tariff to apply to a new customer (i.e. a new connection).[143]

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

We consider that distributors should:

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

This approach balances the need to transition towards cost reflective tariffs with the impact a change in tariff structure might have on customers' ability to control their bills and engage in the electricity market for their long-term benefit. It recognises that customer support for distributors' tariff strategies is an important element of fostering and maintaining users' support for tariff reform generally.[144] If distributors adopt the same (re)assignment triggers there will be a more regular and consistent pace of tariff reform across distributors and jurisdictions.

New customers should face cost reflective tariffs

When new customers connect to the distribution network, the distributor should assign them a cost reflective tariff immediately. Each distributor, except TasNetworks, proposed to assign new customers to cost reflective tariffs in this manner.[145]

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

144 NER cl. 6.18.5.

145 Australian Energy Regulator, *TasNetworks Distribution and Transmission Determination 2019 to 2024*, Issues Paper, March 2018, p 38; Australian Energy Regulator, *Evoenergy Distribution Determination 2019 to 2024,* Issues

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

- such tariffs incentivise efficient use of the network[146] and investment in energy efficiency in the construction of a new building/premise[147]
- new connections have no prior tariff, therefore there is no risk of these customers seeing an increase in their network charges (because they never had any to begin with).

Upgrading customers should face cost reflective tariffs

Existing customers may decide to upgrade their electricity connection by:

- installing embedded generation, such as rooftop solar
- increasing the capacity of their connection, such as installing three-phase power.[148]

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

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

Table 18-18 Distributor's proposed reassignment triggers

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

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.

146 See D.4.1.

147 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

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

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

A 12-month delay is appropriate for meter replacements

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

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

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

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

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

Retail price regulation will influence tariff reassignment

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

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

Should customers choose their network tariffs?

In our 2017 Tariff Structure Statements final decision, we indicated that distributors should propose default assignment to cost reflective tariffs in 2019.[149]

Each distributor, except TasNetworks, proposed default assignment to cost reflective tariffs in the Tariff Structure Statements we received in the first half of 2018.[150]

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

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

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

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

Anytime tariffs are not cost reflective

Opt-out to anytime tariffs are popular with customers and retailers.[151] They give the retailer the ability to face flat energy charges. These charges are easy to understand and manage for customers.[152] However, they do not reflect the cost drivers of the distribution business. That is, they charge customers the same amount per unit of electricity transported during peak and off-peak periods. This signals too much usage during the peak, and insufficient amounts in off-peak, potentially requiring unnecessary investment that can drive up network costs. That's not in the long term interest of customers.

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

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

151 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.

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

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

We consider that distributors should no longer offer customers who are on a cost reflective tariff the ability to opt-out to anytime energy network tariffs. The risks of allowing continued access to anytime tariffs – inefficient use of, or investment in, the network – outweigh the benefits of customers understanding these simple tariff structures.[153] After all, this represents nothing more than continuation of the status quo, acknowledged by policy makers as inappropriate. We note retailers can continue to offer anytime energy retail tariffs when facing cost reflective network tariffs.

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

At the same time, the mismatch between revenue and costs could lead State and Territory regulators to permit retailers a higher retail margin to compensate retailers for the additional risks.[154] Where there is a significant risk of this happening, we consider that we have little option but to continue to allow customers to opt-out to flat network tariffs while the retail price regulation applies.

The ACCC supported prescribed tariffs

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

- a compulsory data sampling period for customers following smart meter installation
- a requirement for retailers to offer flat energy retail tariffs to customers that distributors charge more cost reflective network tariffs
- additional targeted assistance for vulnerable customers.

Stakeholders should consider the ACCC's final recommendations in its Retail Electricity Pricing Inquiry as a package of recommended changes to the existing

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153 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)).

154 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.

requirements of the NEL and the NER. In contrast, our current task is to apply the existing network regulatory framework (in chapter 6 of the NER) within which we are reviewing the current tariff structure statement proposals.

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

Firstly, removing customer's choice through prescribed tariff assignment risks the loss of customer support. This is particularly likely if retailers do not decide to offer customers flat energy tariffs or innovative tariff designs that are easy to understand and lower risk to end-users. In its work for the ACCC, the CSIRO found that most retailers pass on the structure of cost reflective tariffs to end-users, this would mean these customers have very little choice in the tariffs available to them.[155]

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

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

In spite of our concerns, we consider that coupled with complementary measures, prescribed tariff assignment can work. In the Northern Territory, Power and Water Corporation proposed a prescribed assignment policy for residential customers.[156] However, as noted earlier, the Northern Territory Government regulates and subsidises retail electricity prices.[157] This means that the move to prescribed assignment is highly unlikely to come at the cost of customer support for reform, to reduce customer choice or increase retail prices.

Customers should have choice in cost reflective tariffs

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

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

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

157 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.

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

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

> An alternative form of phased approach would be to introduce cost reflective tariffs at both the retail and network level to all customers on a trial basis so that they can gauge their appropriateness. Customers could then be given the opportunity to move to a less cost reflective retail and network tariff structure without penalty if desired (a delayed opt-out approach)…. The ACCC considers that such an approach would not be ideal as it would delay the benefits from greater cost reflectivity, but it may be a workable option if used only for a short time period.[158]

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

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

- tariffs they can understand
- transitional tariffs that reduce the immediate impact of tariff reassignment, allowing vulnerable households to adjust to new tariff structures
- more cost reflective tariffs that are not understandable to the wider customer base but nevertheless benefit customers with elastic and responsive demand, or facilitate innovative retail offers such as peak demand reduction rebates or retailer owned demand management technologies.

This approach has been utilised by Evoenergy since December 2017.[159] Essential Energy also proposed this approach for customers with new technology.[160]

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

What tariffs should distributors offer?

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

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

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

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

We recommend that distributors offer customers:

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

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

- optional location based critical peak prices – these are the most cost reflective tariffs, however can be difficult to understand. Allowing customers (or their retailers) to opt-in to these tariffs will allow customers that can understand these tariffs to use and benefit from them
- optional transitional tariffs – transitional tariffs can reduce the impacts of being assigned to cost reflective tariffs. They may be valuable to some vulnerable customers who need time to adjust how and when they use electricity.

In this section, we:

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

Efficient tariffs align with cost drivers

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

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

Distribution businesses can indeed face two types of issues:

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

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

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

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

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

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

Box A Cost reflectivity of demand and time of use tariffs

The NSW distributors provided us with one-year of smart meter data for a sample of their customers (ranging from 240 to 5,000 individual customers). Using this smart meter data, we calculated each individual customer's demand during the top 80 30-minute periods (that is the 40 hours of greatest system demand) (a proxy for an efficient tariff)[161]

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;

[161] 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.[162]

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

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

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

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

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

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

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

- the difficulties in constructing a cost reflective tariff (e.g. Essential Energy's system covers a wide range of climates and different substation zones will approach capacity constraints at different times of the year); and
- current levels of customer acceptance of time of use tariffs (e.g. Ausgrid currently has 330,000 customers with on time of use energy tariffs).[163]

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.

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

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

Demand tariffs can be cost reflective

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

- anytime demand – where the charge is the maximum 30-minute demand at any point in the day or month
- peak demand – where the charge is the maximum 30-minute demand during a pre-defined peak period during the day or month[164]
- 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.[165]

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

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

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

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

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[164] 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.

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

Table 18-20 Proposed demand charges

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

In our 2017 final decisions on tariff structure statements, we expressed concern with residential demand charges based on a customer's demand over a month or longer. We noted that it is not an individual customer's monthly peak demand that drives network costs, but to the extent which that customer's demand contributes to network congestion near capacity constraints.[166] As above, the ACCC also made this observation.

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

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

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

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

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

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

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

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

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

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

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

Distributors should design transitional tariffs for vulnerable customers

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

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

- reduce the efficiency of price signals to customers
- potentially lead to annual changes in price levels for retailers to explain
- are typically more expensive for around half of all customers.

Default tariff assignment should be to cost-reflective tariffs.

Location based pricing has significant advantages

In the current environment, we consider that time of use energy tariffs and demand tariffs best balance cost reflectivity[167] and customers' ability to understand tariffs[168] 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.[169] By comparison, Endeavour Energy's proposed demand charge would cover over 1,000 hours a year,[170] and Ausgrid's seasonal peak time of use energy tariff would cover over 800 hours a year[171]
- 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[172]
- the extent to which costs vary between different locations.[173]

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

The need for innovative tariffs depends on retailers

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

- demand subscription tariffs where customers select the maximum level of demand they will use during peak hours, but face extra charges for exceeding this limit, similar to a mobile phone plan.[174] Energex and Ergon Energy are both offering

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

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

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

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

[171] 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.

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

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

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

energy subscription 'lifestyle' tariffs, where customers subscribe to a maximum quantity of energy consumption during peak hours[175]

- 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.[176]

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

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

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

Accumulation meters require anytime charges

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

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175 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.

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

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

Table 18-21 Anytime charges for accumulation meters

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

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

Large business should face highly cost reflective tariffs

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

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

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

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

Table 18-22 Proposed large customer tariffs

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

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

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

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

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

Distributors should provide 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.[177]

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.[178] 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.[179] As we discuss below, this could also include replacement of fixed assets at the end of their economic life where changes in demand is a consideration.

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

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

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

Note on LRMC, residual costs and approach to tariff setting

The rules require network tariffs to be based on LRMC.[180] However, not all of a distributor's costs are forward looking and responsive to changes in electricity demand. For example, distributors may need to replace network assets when they are old and/or have deteriorating condition. Hence, if network tariffs only reflected LRMC, distributors would not recover all their costs. Costs not covered by a distributor's LRMC are called 'residual costs'. The rules require network tariffs to recover residual costs in

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177 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.

178 NER, chapter 10 Glossary.

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

180 NER, cl. 6.18.5(f).

a way that minimises distortions to the price signals for efficient usage that would result from tariffs reflecting only LRMC.[181] 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.[182] We consider this aspect in section 18.4.4.2.

Assessment approach

This is the second TSS round for the electricity distribution businesses undergoing a distribution determination.[183] In this round, we are assessing the extent to which a distributor made improvements to its methods for estimating LRMC compared to the first TSS round. In particular, we assessed whether a distributor:

- investigated the inclusion of replacement capex (repex) in their LRMC calculations[184]
- used a minimum of 10 years of forecast data in the calculation of LRMC[185]
- continued to refine their methods for estimating LRMC so their tariffs better reflect efficient costs.[186]

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

Importantly, we consider these criteria allow us to assess the extent to which a distributor has progressed tariff reform as envisioned in the rules, particularly the requirement that a distributor's method(s) of calculating LRMC has regard to:[187]

- the costs and benefits of implementing the method(s) of calculating LRMC
- the additional costs of meeting demand from customers at times of greatest utilisation of the relevant part of the distribution network
- the location of customers and the extent to which costs vary between different locations in the distribution network.[188]

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

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

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

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

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

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

187 NER, cl. 6.18.5(f).

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

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

We discuss each of our criteria in more detail below.

Inclusion of repex in LRMC estimates

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

Assessment criteria:

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

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

In our final decision for the first TSS round, we noted the rules define LRMC as the cost of an incremental change in demand over a period of time in which all factors of production can be varied.[189] In the long run, the level of capacity in a distribution network is a variable factor of production. When assets come to the end of their useful life, distributors have a choice of maintaining their current level of capacity, increasing capacity or decreasing capacity, depending on demand and use of the network. Distributors should not adopt a default position of maintaining existing capacity levels, especially where existing networks have spare capacity and where there are changing patterns of use. We considered LRMC estimates should include replacement capital expenditure and associated operating expenditure. This would promote network capacity in the long run to be at a level that consumers value.[190]

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188 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.

189 NER, chapter 10—Glossary.

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

We also noted not all types of repex should be included in LRMC estimates.[191] Marginal cost refers to the cost of an incremental change in demand.[192] Not all repex is associated with an incremental change in demand. For example, we consider repex driven purely by asset condition would not be included in LRMC estimates.

If a distributor includes repex that is consistent with the definition of marginal cost, the next step is assessing whether it has incorporated such expenditure appropriately into its LRMC estimation method. We assess a distributor's incorporation of repex into its estimation method on a case by case basis. This is because we acknowledge LRMC estimates have not traditionally included repex in the context of Australian network regulation. We consider this second TSS round provides distributors (and other stakeholders, including the AER) with the opportunity to explore and test this aspect of LRMC estimation. Indeed, distributors have proposed several viable methods for incorporating repex into their LRMC estimates in this second TSS round.[193]

Definition of 'long run'

In our final decision for the first TSS round, we noted distributors have typically used timeframes of between 10 and 40 years to estimate long run marginal costs. We considered this timeframe captures the essence of 'long run'.[194]

Assessment criteria:

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

The rules define long run marginal costs as the cost of an incremental change in demand over a period of time in which all factors of production can be varied.[195]

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

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

[192] NER, chapter 10 (definition of long run marginal cost).

[193] See attachment 19 of our respective draft decisions for those distributors with distribution determinations for the 2019–24 regulatory control period (Evoenergy, TasNetworks, Power and Water, Ausgrid, Endeavour Energy and Essential Energy).

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

[195] NER, chapter 10.

accurate forecasts over such a long horizon. The longer the estimation period, the more difficult it becomes to estimate and forecast long run costs.[196]

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

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

LRMC estimation methods

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

- made improvements to their application of the Average Incremental Cost approach;[197] and/or
- explored the use of other estimation methods, such as the Turvey approach.

Assessment criteria:

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

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

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

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

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

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

sophisticated approaches, such as the Turvey approach if they consider it appropriate.[198]

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.[199]

A key question in our assessment (and for distributors in making their TSS) is whether the benefits of more accurate estimates of LRMC outweigh the costs of deriving them.[200] This cost-benefit equation will depend on the circumstance of each business.

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

- **Penetration of interval meters—**There is currently low penetration of interval or more advanced (smart) meters in most jurisdictions. This implies distributors can assign a relatively low proportion of customers to cost reflective tariffs (which should signal LRMC).[201] 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.[202]

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

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

[199] 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.

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

[201] Such as demand charges or time of use charges.

[202] 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.

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

inefficient price signals to most, if not all, customers.[204]

Postage stamp pricing is less costly and simpler to administer for distributors and retailers than locational pricing.[205] It is also arguably more equitable for many end customers. It is therefore unclear the extent to which the industry would, or could, move away from postage stamp pricing in future tariff structure statements. We are not expecting any substantive move by distributors to move towards location-based pricing in this round of TSSs.

- **Transition to marginal cost pricing—**For many distributors, the levels of their cost reflective tariffs differ from their LRMC estimates. This is a legacy of previous practices, when the requirement to consider LRMC was much lower than the current version of the rules.[206] Distributors are transitioning their tariffs toward their LRMC estimates having regard to customer impacts.[207]

Future directions

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

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

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

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204 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.

205 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.

206 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)).

207 NER, cl 6.18.5(h).

As required by the NER, we will be mindful of the costs and benefits of improving LRMC estimation methods in our assessment of future TSS.[208] In the sections above, we acknowledged several factors in the current stage of tariff reform that may limit the benefits of using more sophisticated estimation methods such as the Turvey method.

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

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

  However, the AEMC's metering rule change took effect from 1 December 2017. This should promote increasing penetration of interval meters in the NEM.[209] Distributors should monitor the rate of interval meter penetration and consider the extent to which it can accelerate tariff reform in the third TSS round. This includes considering the benefits to distributors and its customers of deriving (and signalling) more accurate estimates of LRMC.

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

  The higher costs of more accurate methods to estimation LRMC may be justifiable where a distributor proposes tariffs that send locational signals of congestion. In future TSS rounds, a distributor may experiment with using such methods if it proposes to trial tariffs in particular areas of its network, for example.[210]

  Also, having regard to location when estimating LRMC does not require a distributor to actually apply location-based pricing. In this second TSS round, for example, Endeavour Energy produced two separate LRMC estimates: one for areas of stable or decreasing demand, and another for areas of increasing demand. However, Endeavour Energy still proposed to apply postage stamp pricing for the 2019–24 regulatory control period.[211]

  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

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

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

210 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.

211 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.

management outweigh the costs. Location-based LRMC estimates would assist in the assessment of project costs with and without demand management in constrained areas of the network.

We consider this is consistent with the rules requirement that LRMC estimates have regard to the extent to which costs differ between locations (without actually applying locational pricing).[212] It also provided Endeavour Energy with further information regarding the appropriate LRMC estimate on which to base its prices.[213]

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

Distributors may use different estimation methods to account for different types of marginal costs. Ausgrid did so in this second TSS round to measure the different contributions to LRMC of augmentation capex and replacement capex.[214] Distributors may use different estimation methods, where one method acts as the 'primary' estimation method, while a second method acts as a 'sanity check'. Or, distributors may use different estimation methods to derive a range for LRMC, rather than point estimates, as Ausgrid did in this second TSS round.[215]

On a final note, we propose consulting with distributors more regularly outside of the distribution determination process on progressing LRMC estimation methods. This is consistent with a suggestion from Energy Networks Australia in the first TSS round who stated the industry should devote resources to improve the estimation of LRMC.[216] 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.

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

213 NER, cl 6.18.5(f).

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

215 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.

216 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 Power and Water's retail customers for direct control services.[217]

Procedures for assigning and reassigning retail customers to tariff classes

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

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

1. Power and Water's customers will be taken to be "assigned" to the tariff class which Power and Water was charging that customer immediately prior to 1 July 2019 if:

   (a) they were a Power and Water customer prior to 1 July 2019, and

   (b) they continue to be a customer of Power and Water as at 1 July 2019.

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

2. If, from 1 July 2019, Power and Water becomes aware that a person will become a customer of Power and Water, then Power and Water will determine the tariff class to which the new customer will be assigned.
3. In determining the tariff class to which a customer or potential customer will be assigned, or reassigned, in accordance with paragraphs 2 or 5, Power and Water will take into account one or more of the following factors:

   (a) the nature and extent of the customer's usage

   (b) the nature of the customer's connection to the network

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

   (a) that customers with similar connection and usage profiles are treated on an equal basis

   (b) those customers who have micro–generation facilities are treated no less favourably than customers with similar load profiles but without such facilities.

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

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

5. Power and Water may reassign an existing customer to another tariff class in the following situations:

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

   (b) Power and Water believes that:

      i. an existing customer's load characteristics or connection characteristics (or both) have changed such that it is no longer appropriate for that customer to be assigned to the tariff class to which the customer is currently assigned, or

      ii. a customer no longer has the same or materially similar load or connection characteristics as other customers on the customer's existing tariff, then Power and Water may reassign that customer to another tariff class.

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

6. Power and Water must notify the customer's retailer in writing of the tariff class to which the customer has been assigned or reassigned, prior to the assignment or reassignment occurring.

7. A notice under paragraph 6 above must include advice informing the customer's retailer that they may request further information from Power and Water and that the customer or customer's retailer may object to the proposed reassignment. This notice must specifically include:

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

   (b) that if the objection is not resolved to the satisfaction of the customer or customer's retailer under Power and Water's internal review system within a reasonable timeframe, then, to the extent resolution of such disputes are with the jurisdiction of an ombudsman or like officer, the customer or customer's retailer is entitled to escalate the matter to such a body

   (c) that if the objection is not resolved to the satisfaction of the customer or customer's retailer under Power and Water's internal review system and the body noted in paragraph 7(b) above, then the customer or customer's retailer is entitled to seek a decision of the AER via the dispute resolution process available under Part 10 of the NEL.

8. If, in response to a notice issued in accordance with paragraph 6 above, Power and Water receives a request for further information from a customer or customer's retailer, then it must provide such information within a reasonable timeframe. If Power and Water reasonably claims confidentiality over any of the information requested by the customer or customer's retailer, then it is not required to provide

that information to the customer or customer's retailer. If the customer or customer's retailer disagrees with such confidentiality claims, he or she may have resort to the complaints and dispute resolution procedure, referred to in paragraph 7 above (as modified for a confidentiality dispute).

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

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

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

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

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

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

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

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

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

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