ADDENDUM TO OUR TARIFF STRUCTURE STATEMENT

EXPLANATIONS & REASONING

4 October 2016

TABLE OF CONTENTS

LIST OF TABLES

LIST OF FIGURES

LIST OF ATTACHMENTS

1. Overview of our TSS
2. Indicative NUOS Pricing Schedule
3. IPSOS Public Affairs stakeholder engagement report
4. Policies and procedures for assignment and reassignment of tariffs
5. Alternative Control Pricing Schedule
6. Compliance report from Farrier Swier
7. Updated Long Run Marginal Cost model

DISCLAIMER

GLOSSARY

Term	Meaning
2014-19 Determination	Our current regulatory control period running from 1 July 2014 through to 30 June 2019.
AEMC	Australian Energy Market Commission – the rule makers for Australian electricity and gas markets.
AER	Australian Energy Regulator – the national regulator that oversees the electricity industry.
Alternative Control Services	These are specific user requested services. They comprise: *Public Lighting*; *Type 5 & 6 Metering* (generally residential and small business customer meters); and *Ancillary Network Services*.
Charging parameters	The specific charge characteristics for a component within the tariff structure. For example, the energy charge component may vary with the time of day in which electricity is consumed.
CPI	Consumer Price Index.
DBT / Declining block tariff	A tariff whereby the network charge becomes progressively cheaper as customer consumption increases.
Direct control services	Services regulated by the AER under the National Electricity Rules. Direct control services comprise Standard Control Services and Alternative Control Services.
DNSP	Distribution Network Service Provider.
Financial year	The year running from 1 July in any year to 30 June the following year.
HV	High voltage.
IDT	Inter distributor transfer – a type of customer.
kVA	Kilovolt ampere.
kW	Kilowatt.
kWh	Kilowatt hour.
LRMC	Long run marginal cost – economic term for the cost of adding one more unit of demand to the network.
LV	Low voltage.
NEL	National Electricity Law.
NEO	National Electricity Objective.
NMI	National Meter Identifier – each meter installation has a unique NMI.
NUOS	Network Use of System – this is the charge for using Essential Energy's distribution network, as well as the pass through of transmission type costs and jurisdictional scheme amounts such as the climate Change Fund.
Peak demand / peak load	The maximum electricity demand customers place on the electricity network.
Solar PV	Solar Photovoltaic system.
Standard Control Services	Comprise Essential Energy's core activities from access to, and supply of, electricity to customers.
Tariff	A cost charged to network customers to recover the efficient costs of providing network services.
Tariff class	A group of customers that share a common set of characteristics that allows them to be grouped together to ensure that similar customers pay similar prices.
Tariff component	Tariffs comprise one to three tariff components that work together to reflect the efficient costs of providing network services to customers. The three components are: Fixed charge, Energy charge and Demand charge.
Tariff schedule	The list of prices and tariff structures for each of our tariffs, published annually. Also referred to as Network Price List and Explanatory Notes.
Tariff structure	How tariff components are combined to give the tariff structure.
The Rules	The National Electricity Rules.
TOU	Time of Use – a meter or tariff that varies with when electricity is consumed in either a: peak; shoulder; or off-peak period.
TSS	Tariff Structure Statement.
TUOS	Transmission Use of System – this is the cost Essential Energy pays for the use of transmission networks.

ABOUT OUR TARIFF STRUCTURE STATEMENT

Essential Energy's initial Tariff Structure Statement (TSS) for the period 1 July 2017 to 30 June 2019 was submitted to the Australian Energy Regulator (AER) on 27 November 2015.

In its draft decision, released on 2 August 2016, the AER did not approve this TSS as it was not considered to be fully compliant with the National Electricity Rules ('the Rules').

Essential Energy submitted this revised TSS, which addresses those areas of non-compliance and, in particular, demonstrates how we have adopted the new network pricing objective and complied with the associated pricing principles set out in Section 6.18 of the Rules, to the AER on 4 October 2016. It also incorporates feedback from our customers and stakeholders. The AER will assess this revised TSS and make a final decision before any tariff structures and associated pricing apply from on 1 July 2017.

Our revised TSS seeks to provide a clear explanation and facilitate a greater level of understanding of our network tariffs to enable customers to make more informed choices about how they use electricity.

As requested by the AER, the revised TSS specifically addresses only the requirements of section 6.18.1(A) of the Rules. This addendum to the TSS provides explanations and reasons for changes from our initial TSS. This addendum, Attachment 8 to the TSS, is to be read in conjunction with the TSS and contains:

- results of stakeholder consultation undertaken following the AER draft decision
- explanations of any changes made to our TSS following the AER's draft decision and our recent stakeholder consultation
- reasons why some changes to our TSS proposed by the AER in its draft decision have not been adopted
- a summary of the strategy and enhancements we are considering for our next TSS and future pricing directions.

Feedback on our TSS

A key objective of this TSS is to reflect the views of our customers and stakeholders. Essential Energy's customers and stakeholders can provide feedback and comments on Essential Energy's TSS either to the AER at www.aer.gov.au or through the following channels:

Channel	Contact details
Email	ourplans@essentialenergy.com.au
Post	Manager Network Regulation Essential Energy PO Box 5730 Port Macquarie NSW 2444
Phone	13 23 91
Twitter	twitter.com/essentialenergy

1. EXECUTIVE SUMMARY

On 27 November 2014, the Australian Energy Market Commission (AEMC) made a new Rule that requires distribution network service providers (DNSPs) to develop prices that better reflect the costs of providing network services to customers. This document accompanies our revised TSS, a requirement of the new Rule. It covers the two-year period commencing 1 July 2017.

The key objective of this Explanations and Reasoning document is to ensure our customers have a clear understanding of:

- stakeholder consultation we have undertaken following the AER's draft decision
- how that consultation has helped shape our revised TSS
- changes we have made to our initial TSS put forward to the AER on 27 November 2015 and the reasons for those changes
- reasons why we have not proceeded with some of the suggestions the AER put forward in its draft decision
- our future tariff setting methodology and the enhancements we plan to incorporate in our next TSS and future regulatory periods.

Network tariffs form a key component of our overall demand management strategy. In developing our tariffs, we aim to reduce long-term average prices by promoting efficient network investment and utilisation.

We have identified that some of our existing tariff components do not currently comply with our estimate of the long run marginal cost (LRMC) concept required by the Rules. In accordance with the Rules, we will progressively transition our customers to more efficient price structures and price levels over time, recognising that as an estimate –based on methodological and input choices – it is more of a guide than a fixed constraint.

As metering technology in our network area continues to improve – assisted by the introduction of metering contestability from 1 December 2017 – we will be better able to develop more cost reflective tariff structures for our customers. As such, this TSS should be seen as a stepping stone towards this goal.

We have developed our revised TSS utilising feedback from the AER in its draft decision and in conjunction with our stakeholders. Throughout August 2016, we held numerous face-to-face and one-on-one discussions based around topics raised in the AER's draft decision with members of our customer advocacy and other stakeholder groups, as well as Essential Energy's Customer Advocacy Group. These targeted sessions provided a direct means of gauging stakeholder views and allowed us to engage with all relevant groups in the limited amount of time allowed between publication of the AER's draft decision and our revised TSS. Written responses were also encouraged as a follow-up to each session.

IPSOS Public Affairs was also engaged to consult directly with those business customers who no longer meet eligibility requirements for the tariff to which they are currently assigned and need to move to a new tariff structure. The majority of these customers are likely to experience material increases in their bills and we are working with them to determine an appropriate transition pathway towards more cost reflective network pricing.

Managing suitable transition paths for all our customers has been a priority for this TSS. As such, many of our proposed tariff structures are largely identical to our existing tariff structures and will have no, or minimal, impact on the majority of our customers. However, in response to stakeholder feedback, we have made some refinements and additions to our initial TSS to provide the majority of customers with more tariff choices and facilitate transition towards cost reflective pricing in our network area.

Essential Energy operates under a revenue cap control mechanism which prevents us earning more over time than the revenue the AER has determined is reasonable and efficient.

We set our tariff prices based on estimated consumption and demand levels to recover our revenue allowance. However, since the level of revenue we receive is driven by actual demand levels, we tend to collect a level of revenue that differs to our regulated allowance in any year. To correct this, we adjust a following years' prices to either pay back any over-recovery, or collect any under-recovery.

Additionally, our tariff prices are aimed at ensuring that the revenue earned from each customer reflects how their consumption choices impact our actual network costs. While actual network tariffs for each year will be determined through the AER's annual pricing proposal process, they must comply with the structures set out in our approved TSS.

1.1 Changes from our initial TSS published in November 2015

- We will offer a flat rate tariff structure for our existing small residential and business customers instead of the current declining block tariff (DBT) structure.
- We will introduce more cost reflective charging windows and associated pricing to customers on time of use (TOU) and demand tariffs with an interval (or higher capability) meter. These charging windows replace the morning peak window with an extension of the daytime shoulder window.
- We will introduce a new TOU tariff structure for residential and small business customers with interval meters. These TOU tariffs will adopt the more cost reflective charging windows noted above, rather than the legacy charging windows that are available to our customers with basic accumulation meters with TOU capability or Type 5 meters.
- We will introduce opt-in residential and small business customer tariffs with a demand component.
- Assign all new connections, meter upgrades and solar PV installations for residential and small business customers to the TOU tariff appropriate to their metering technology in the first instance, with the option to opt-out to an alternative tariff.
- We will implement a specific transitional tariff for approximately 1,000 low voltage business customers currently assigned to an incorrect tariff who need to move to a demand based tariff and, in doing so, will experience an increase in their bills.

1.2 What has not changed following the AER's draft decision

- Given the cost imposition for customers and the introduction of meter contestability from 1 December 2017, we have not altered the proposed charging windows for existing TOU customers with basic accumulation meters.
- Since some areas of our network peak in winter, others in summer and many in both seasons, we have not implemented seasonal TOU windows. This decision is supported by most of our customers and stakeholders, who have stated that they favour simplicity in tariff design. On review, seasonal tariffs were seen as adding increased potential for significant seasonal price fluctuations to customer bills, and a layer of complexity that should be avoided if possible. Implementing seasonal tariffs for our accumulation meters with TOU capability would also involve a significant annual cost to customers that was not clearly outweighed by the benefits.

2. ENGAGING OUR CUSTOMERS AND STAKEHOLDERS

Essential Energy's network area spans regional cities, rural farmland and remote rural locations. Understanding the composition of our customer base is critical to meeting the diverse connection, consumption and billing needs of both individual customers and customer groups.

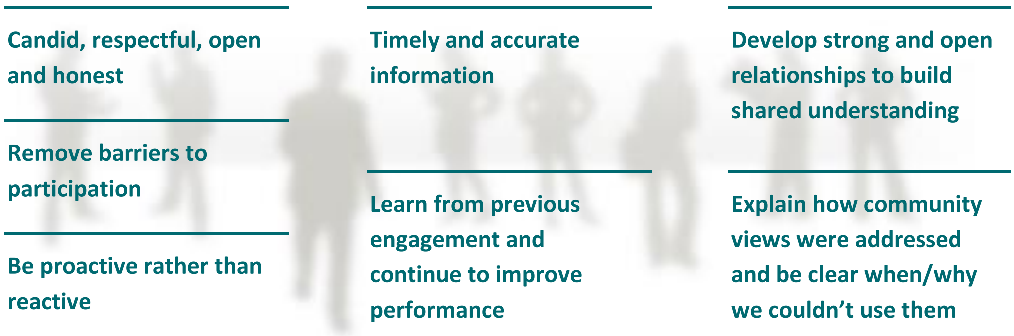
On the whole, our customers continue to want tariffs that encourage a low cost, reliable supply that does not discourage or create disincentives for customers to install alternative power sources, such as solar PV or battery storage. They also want tariffs to be designed to support energy conservation and efficiency; for example, by encouraging customers to turn off non-essential appliances or allowing them to shift use of less important appliances to off-peak times under a TOU tariff.

This section explains how we have engaged with customers and stakeholders following the AER's draft decision on our TSS and how we have taken their feedback into consideration in developing our revised tariff structures.

2.1 Engagement principles and approach

Essential Energy operations are funded by our customers. Customer engagement helps inform Essential Energy on how we operate our business. Our customer engagement principles are outlined below.

Figure 2-1: Our customer engagement principles



2.2 Our stakeholder engagement process

Since the AER delivered its draft decision on our TSS, we have undertaken numerous face-to-face and one-on-one stakeholder discussions with consumer advocacy groups and Essential Energy's existing Customer Advocacy Group. These discussions were based on topics raised in the AER's draft decision and provided the opportunity for stakeholder groups to give direct feedback in an intimate setting. This approach worked well, as it allowed us to meet with representatives of all relevant groups within a limited period of a time to understand their issues and hear their views. A full list of our stakeholder meetings is contained in Table 2-1 below.

Table 2-1: Stakeholder engagement schedule

Date	Stakeholder
28 April 2016	The Energy & Water Ombudsman NSW
28 April 2016	Energy Consumers Australia
17 May 2016	Public Interest Advocacy Centre
25 May 2016	Origin Energy and AGL
11 August 2016	Solar Citizens
11 August 2016	NSW Farmers Association
12 August 2016	St Vincent De Paul
15 August 2016	Ethnic Communities Council of NSW
15 August 2016	The Energy & Water Ombudsman NSW
16 August 2016	NSW Irrigators Council
16 August 2016	Cotton Australia
16 August 2016	Public Interest Advocacy Centre
16 August 2016	Energy Consumers Australia
19 August 2016	Origin Energy
19 August 2016	Energy Australia
26 August 2016	Alternative Technology Association
31 August 2016	NSW Council of Social Service
19 September 2016	Total Environment Centre

In addition to verbal feedback, stakeholders were able to provide written responses following each meeting. In developing this revised TSS, we have balanced all views obtained through these consultation processes with those of the AER and our obligations under the NER.

IPSOS Public Affairs was also engaged to specifically consult with the group of significantly impacted business customers who need to transition to TOU or demand based tariffs (see section 5 for more details).

A summary of the key messages from our stakeholder feedback is shown in Figure 2-2 below. Our stakeholder engagement strategy is discussed in more detail in *Attachment 9 – NNSW TSS Stakeholder Engagement Strategy* of our initial TSS.

Figure 2-2: Key messages from our stakeholder engagement

2.3 How we have considered customer and stakeholder feedback

Our customer and stakeholder feedback has informed our revised tariff structures, resulting in:

> A flat rate tariff structure instead of a DBT structure for our residential and small business customers (our stakeholders were very much against our DBT structure).

> New, more cost reflective charging windows for all customers with interval (or higher capability) meters:

- These charging windows replace the morning peak window with an extension of the daytime shoulder window – a clear request from our stakeholders.
- Common charging windows across winter and summer have been retained, based on customer preferences for tariff simplicity and reduced seasonal bill fluctuations.

> Residential and small business customer tariffs with a demand component – a consistent request from a small group of users throughout the TSS process.

> Assignment of appropriate TOU tariffs (depending on meter type) to customers with meter upgrades, solar PV installations and new residential and small business connections, with the option for customers to select an alternative tariff if they prefer. This will facilitate tariff reform across our customer base.

> Implementation of a specific transitional tariff for approximately 1,000 low voltage business customers currently on DBTs or TOU tariffs who need to move to a demand based tariff and, in doing so, will experience an increase in their bills.

More discussion on these themes, as well as the other areas of feedback we received, is detailed in section 3.

2.4 Future customer and stakeholder engagement

We will continue to engage and consult with our customers and stakeholders during 2017 and 2018 to inform development of our next TSS as part of our regulatory proposal process for the 2019-24 period.

In the meantime, we encourage customers and stakeholders to provide any comments on this TSS either to Essential Energy, or directly to the AER.

The Rules allow Essential Energy to seek amendments to an existing TSS only for events that occur beyond our reasonable control and that could not have reasonably been foreseen at the time of writing the TSS. However, we will only update our tariff structures after consultation with our customers.

It is important to note that Essential Energy operates under a revenue cap control mechanism which prevents us earning more than the revenue the AER has determined is reasonable and efficient.

Our tariff prices are aimed at ensuring that the revenue earned from each customer reflects how their consumption choices impact our actual network costs.

Our structures may change in future TSS periods to:

- account for capability changes in the metering population
- reflect customer preferences
- improve price signals to customers
- encompass changes within the electricity market that impact on our costs.

3. ADDRESSING AREAS OF AER CONCERN IN OUR INITIAL TSS

3.1 Flat rate tariff structure versus a declining block structure

Most of our stakeholders, including the AER, did not believe that our proposed DBTs for residential and small business customers provided efficient pricing signals for custoerms as an alternative to a flat rate tariff.

DBTs are likely to encourage electricity consumption and discourage investment in energy efficiency measures, and result in low-use users subsidising higher-use users. Some stakeholders preferred a TOU tariff to a flat rate tariff, but accepted that our current metering population made this option unviable.

While we believe that DBTs do represent a cost reflective option for the majority of customers in our network area, in response to stakeholder preferences we are now proposing a flat rate tariff structure for our residential and small business tariffs in place of the DBT.

The flat rate structure is easy for our customers to understand, will ensure that both high and low usage customers pay for residual costs in proportion to their use of electricity and is generally better aligned with Retailer offerings.

3.2 Charging windows

In the absence of ideal cost reflective pricing, DNSPs utilise charging windows that signal times when the whole network is likely to experience high levels of demand. Charging windows must be:

> wide enough to capture peak demand periods

> not so short as to make it easy to shift demand, simply moving the network peak from one-time period to another

> wide enough to ensure customers have an ability to respond to the price signal and manage their bills by spreading their load over the period.

Due to the limited data provided in our initial TSS to support our proposed charging windows, stakeholders questioned our proposed charging windows.

The AER queried the relevance of our TOU charging windows – in particular, the application of a weekday morning peak and the lengths of our weekday shoulder period and weekday evening peak. In the absence of new data being presented in our revised TSS to support these charging windows, the AER asked Essential Energy to present the costs of conducting either a special project, or a project undertaken in conjunction with another activity like meter reading, to reprogram the charging windows for the basic accumulation meters in our network area.

The charging windows put forward in the initial TSS are a legacy of our existing metering technology. The majority of our meters are basic accumulation meters. Some of these have TOU ability and are currently aligned to our existing TOU charging windows. We based the charging windows in our initial TSS on these and applied the same windows across all tariff types.

We have now conducted further analysis and revisited our demand data to determine whether more cost reflective charging windows can be applied to our network.

In determining our proposed charging windows we have taken into consideration:

> network demand and the profile of network congestion over the day

> cost versus benefit of any proposed changes

> stakeholder preferences.

The following section analyses these considerations and implications for Essential Energy's proposed charging windows.

3.2.1 Network demand and congestion

Network demand

The demand data shown in the initial TSS was for the 2014-15 year only. Since 2014-15 did not contain any major heatwaves or cold shocks, it may not be representative of peak network demand in an average year.

We have presented a fuller range of data in Figure 3-1 below that provides a clearer picture of demand on our network. Figure 3-1 compares the average daily network-wide demand for 2014-15 and 2015-16, split between summer and winter, as well as peak day data for the 2014-16 period against our legacy charging windows.

It demonstrates that:

> The evening peak and winter morning peak align with our legacy peak windows.

> The average winter evening peak is higher than the summer peak, but it is not materially so, particularly when actual peak demand days are considered.

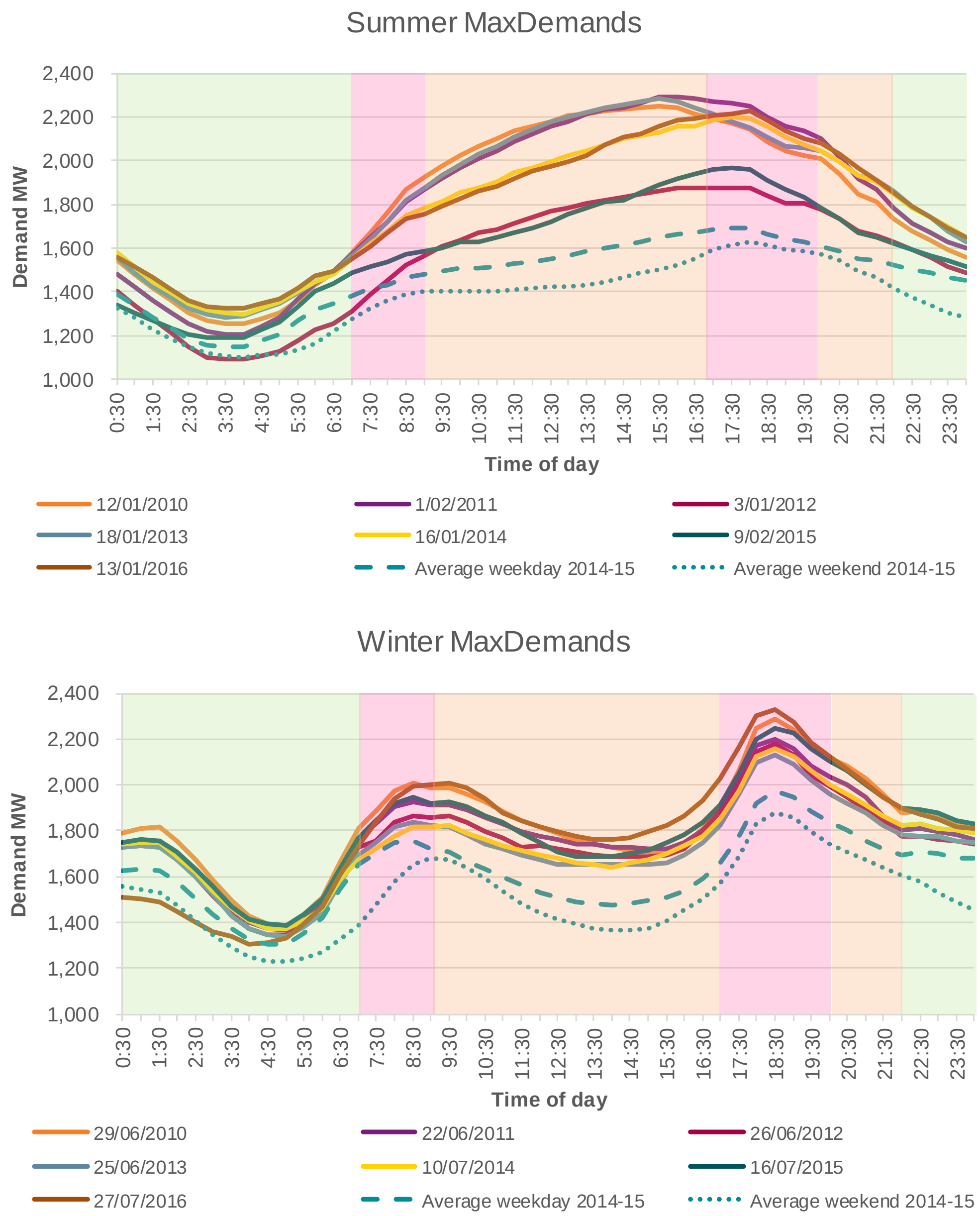
> Although our winter morning peak is quite distinct, it is not as high as the evening peak and covers a wider period than the existing morning peak window.

> Morning demand in summer is not substantial but forms part of the gradual increase in demand during the day heading to the evening peak.

> The winter evening peak window is narrower and slightly later than the summer equivalent.

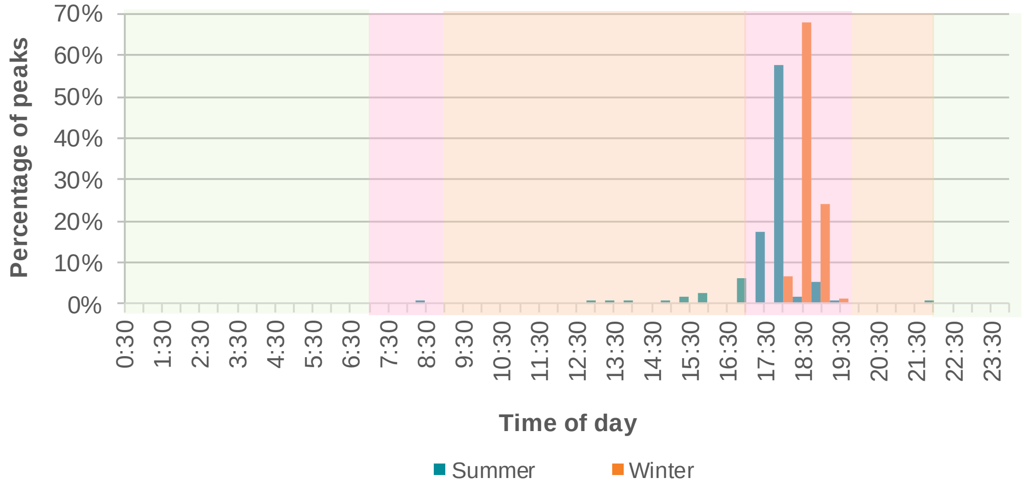
> There is sufficient evidence to support changing the morning peak to shoulder rates (but not off peak) with the increases in demand visible in both summer and winter in morning periods.

Figure 3-1: Summer and winter peak days and average daily demand profile against legacy charging windows



This split between summer and winter is also apparent when looking at the distribution of 2015-16 daily peaks, as shown in Figure 3-2. The underlying data shows that 89.9 per cent of daily summer peaks and 100 per cent of daily winter peaks fall within our proposed evening peak window, compared with only 0.9 per cent of daily summer peaks and zero per cent of daily winter peaks falling in our legacy morning peak window.

Figure 3-2: Comparison of summer and winter distribution of daily peaks (weekdays), 2015-16



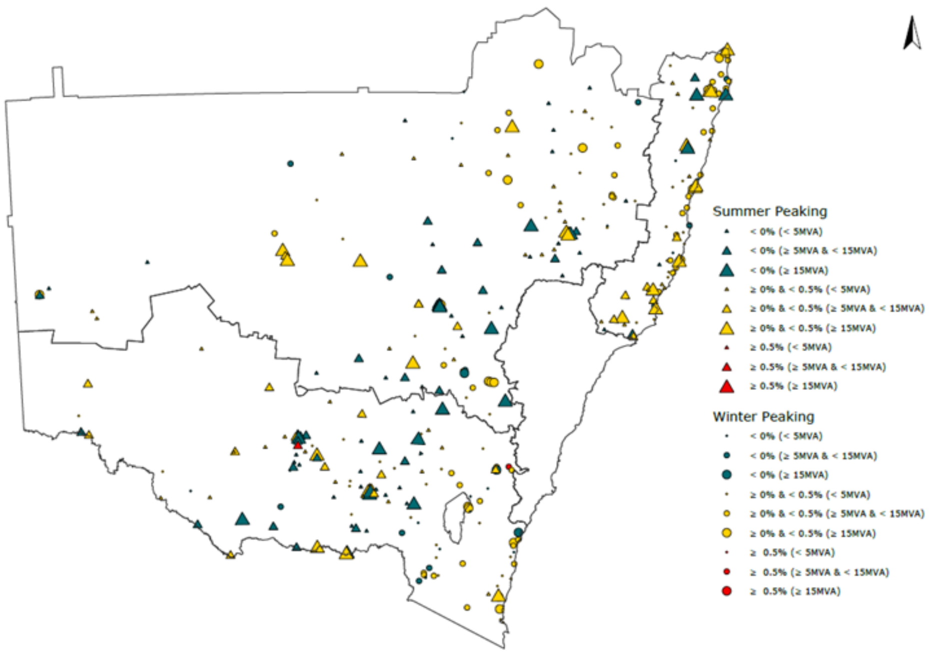
This data also shows that 96 per cent of overall weekday network peaks occur within our legacy morning and evening peak windows, with the remaining 4 per cent occurring in shoulder windows.

Localised network congestion

Network demand varies across areas within our network. As the AER observed in its draft decision, there appears to be some variation between the network-wide winter and summer demand profiles. However, this variation is not the same across Essential Energy's network. Some areas exhibit common winter and summer peak periods, while others do not.

Figure 3-3 highlights zone substation pressures across our network and demonstrates that some areas of our network peak in winter, others peak in summer and some peak in both. The red symbols indicate the zone substations experiencing the greatest demand pressure, through to the green symbols experiencing the least pressure. Triangles represent summer peaking and circles winter peaking. The larger the symbol the larger the capacity of the substation.

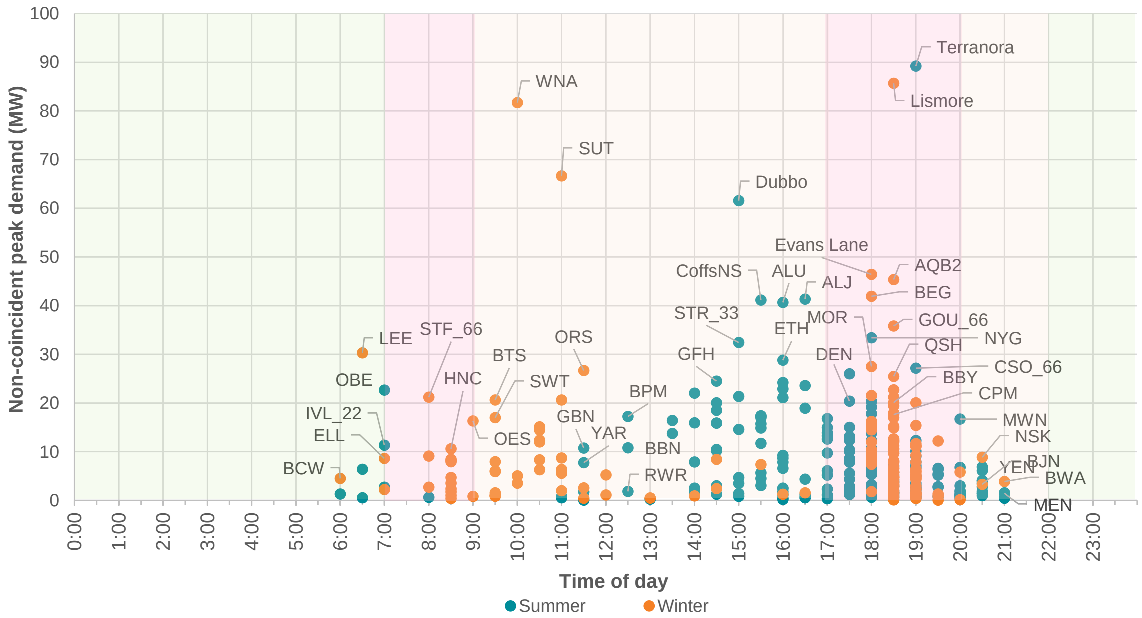
Figure 3-3: Zone substation peaks across our network



Although the network wide demand profile is important when determining network congestion, so too are the demand profiles for areas within it – that is, at the zone substation level. In practice, these localised congestion outcomes drive our investment.

Figure 3-4 shows the non-coincident peak demand for Essential Energy's zone-substations, split by the 2014-15 season. This shows that, although the peak demand period falls within the evening charging window for many of our zone-substations, there is a significant number that do not peak during that window. The figure also shows that the peaks are spread across summer and winter.

Figure 3-4: Non-coincident peak demand by season and zone-substation, 2014-15



Findings from network demand and congestion analysis

At a high level, the above analysis suggests that recent patterns of congestion on our network do support:

- potentially removing the summer morning peak window and extending the shoulder window to cover it
- adopting different windows for winter and summer seasons, but setting the tariffs at similar levels (given the daily peaks are similar).

However, there is also evidence:

- that the spread of peaks across the network when viewed at the zone substation level makes it difficult to determine the optimal windows for each season
- the windows for summer and winter are not that dissimilar
- that if a single evening peak window is to be adopted for both seasons, then the existing 5pm to 8pm window should be retained.

3.2.2 Assessment of costs versus benefits of reprogramming our basic accumulation meters with TOU capability and Type 5 meters

We have approximately 302,000 basic accumulation meters with TOU capability and 551 Type 5 meters spread across our network area. If we assume that each meter requires 30 minutes for upgrading, including travel time to the location, reprogramming the meter and updating the meter data and tariff rate in the billing system, the associated direct cost would be at least $67 per meter, based on our current approved fieldworker rates for our ancillary network services fees[1]. When this is multiplied by the estimated 302,000 applicable meters, this equates to over $20 million.

[1] Price Schedule for Ancillary Network Services – 1 July 2016, Essential Energy website, Table 2-1: Applicable Labour Rates https://www.essentialenergy.com.au/asset/cms/pdf/electricitynetwork/PriceScheduleForAncillaryNetworkServices1July2016.pdf

Even if the time to complete each reprogramming and data update was halved to a total of 15 mins (an extremely low estimate given the size of our network area) the associated cost still exceeds $10 million. It is difficult to see the benefit of the improved price signals to customers arising from this reprogramming outweighing such a cost. In addition, following the introduction of metering contestability it is likely that all meters will be replaced with smart meters, and this will further erode the potential benefits. If a seasonal charging window was also applied to these meters, this cost would be incurred twice every year.

Essential Energy's meter reading contractor has confirmed that its staff may not have the necessary accreditation to be able to reprogram a meter. Additionally, the contractor has optimised meter reading rounds to ensure that staff are fully engaged. Since reprogramming is estimated to require five minutes per meter and reprogramming 12 meters per day would add almost an hour of extra work, there is no capacity for meter upgrades to be undertaken during normal rounds.

The cost of contracting additional external staff undertake this work is likely to be similar to the cost for Essential Energy staff to complete the work – between $10 and $20 million dollars per cycle change.

Our meter reading contractor has investigated whether software could be used in conjunction with each meter reader's smartphone and meter reading probe to expedite reprogramming. However, the cost estimate for developing software needed to cover all the different meter brands, associated license fees and development and testing time was at least $1 million. When added to the cost of additional Essential Energy staff time to develop a script to upload the data into our billing systems, this option is estimated to total at least $2 million and take at least eight months to fully develop and test. While this compares favourably to the other two options outlined above, it would be unlikely to be operational until June 2017 – only six months prior to introduction of meter contestability on 1 December 2017.

We anticipate that many of our customers currently participating in the NSW Solar Bonus Scheme will upgrade their meters once the Scheme ends on 31 December 2016, and that a large number of our customers will upgrade to smarter meters following the introduction of metering contestability. Since market forces are likely to drive meter upgrades in the short term, the timeframe for achieving benefits arising from the costs of reprogramming many of these low technology meters will be cut short. As a result, we do not see the benefits of reprograming exceeding the associated costs to customers.

3.2.3 Stakeholder feedback

Our stakeholders supported charging windows that are reflective of network demand, but they generally did not support the work and costs that would be required for reprogramming our basic accumulation meters with TOU capability and our Type 5 meters. Reprogramming costs, regardless of whether the time and money was spent on a stand-alone project or one carried out in conjunction with existing meter reads, were seen as a waste of money given metering contestability begins next year.

In relation to seasonal charging windows, some stakeholders queried whether we had scope to introduce seasonal tariffs during consultation for our initial TSS. While there are some small engaged customer groups who are at ease with more complex tariff structures, the majority of our customers and stakeholders have made it clear that they favour simplicity in tariff design. On this front, seasonal tariffs were seen as adding increased potential for significant seasonal price fluctuations to customer bills, and a layer of complexity that should be avoided if possible.

In the absence of more uniform regional demand patterns, we see the introduction of seasonal charging windows at this stage as being akin to introducing locational tariffs. This was a concept that was wholeheartedly rejected by our stakeholders in our initial TSS consultation.

3.2.4 Our proposed charging windows

We have weighed up the evidence and stakeholder feedback in relation to changing our charging windows. Table 3-1 below summarises our conclusions against the AER's requests.

Table 3-1: Analysis against AER requests for Essential Energy's charging windows

AER request	Network congestion	Other considerations	Our decision
Review the applicability of the weekday morning peak window	> Summer loads do not support a morning peak window > However network pressures are on par with the shoulder period	> Customers support simplicity, one peak is simpler to understand than two > The cost of removing the morning peak window for basic meters with TOU capability and Type 5 meters is prohibitive	> Retain for existing TOU tariffs aligned to basic accumulation meters or Type 5 meters > Change the morning peak to a shoulder window for existing and new TOU tariffs and demand tariffs aligned with interval (or higher capability) meters.
Consider adopting different summer and winter windows to reflect the different levels of congestion in the seasons	> Supported based on network-wide congestion > There is locational evidence that supports retaining the existing windows	> Customers support the simplicity of having common windows across seasons > The cost of adopting this for basic meters with TOU capability and Type 5 meters is prohibitive	> Retain year round charging windows with no seasonal variability for all tariffs

As such, in this TSS we propose the following:

1. No change to the existing charging windows for our TOU tariffs associated with basic accumulation meters and Type 5 meters.
2. Introduction of more cost reflective charging windows for TOU and demand tariffs associated with interval (or higher capability) meters – the existing morning peak will be replaced with an extension of the day-time shoulder period.
3. Introduction of a new TOU tariff based on these new charging windows for residential and small business customers with interval (or higher capability) meters. In conjunction with our revised tariff assignment policy for these customers (see section 3.5) this tariff will further progress the speed of our tariff reform while also improving price signals for the bulk of our customers.
4. No seasonal windows for our TOU and demand tariffs.

Our proposed charging windows for different meter types are shown in Figure 3-5 and Figure 3-6 below.

Figure 3-5: Our proposed charging windows for TOU tariffs aligned with basic accumulation meters and Type 5 meters

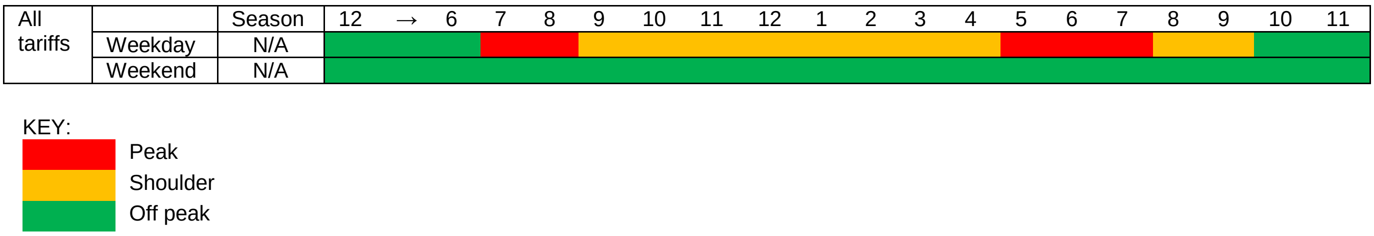
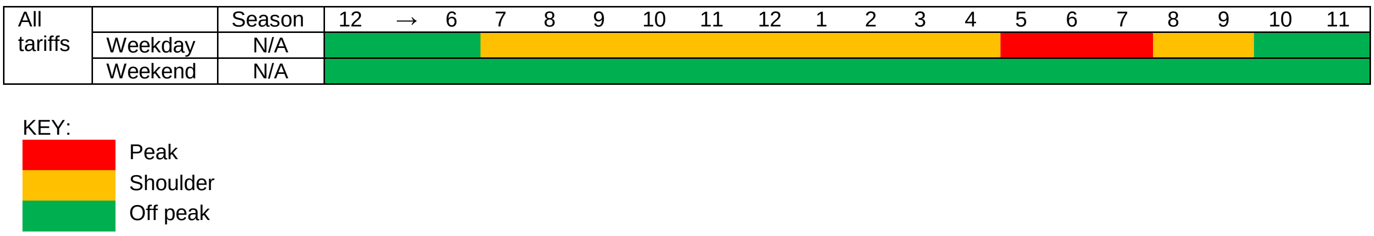


Figure 3-6: Our proposed charging windows for tariffs aligned with interval (or higher capability) meters



3.3 Different rates for shoulder and peak charging windows for large business customers

Applying more cost reflective windows and revisiting the spread of our residual costs across our tariffs on this basis has allowed us to begin introducing a wider range in our rates between shoulder, peak and off-peak windows, to better reflect our costs of supplying customers during those time periods.

Applying more distinct rates between the peak and shoulder periods, in particular, was a request from many of our stakeholders. We have taken this on board and started to increase the range between our tariff rates for our peak and shoulder periods in this revised TSS. We have been limited in our ability to drastically shift charging rates as we have had to balance the relative impact on customers. We expect, however, to continue increasing the range between charging window rates in future TSSs. This will make TOU pricing more attractive to our customers by sending improved price signals to increase the efficient use of the network.

When combined with our improved charging windows for customers with interval (or higher capability) meters (see section 3.2.4) and our revised tariff assignment and reassignment process (see section 3.5) this change should further progress the speed of tariff reform in our network area.

3.4 Introduction of residential and small business customer demand tariff

A demand tariff for residential and small business customers has been a constant request from a small group of stakeholders throughout the TSS process. In our initial TSS, we did not offer a demand tariff due to the existing high prevalence of low level metering technology for these customers. This means we have limited data on which to base any demand charge element. This approach was accepted by the AER in its draft decision.

Despite this agreement, we have chosen to make a first step towards a demand based tariff for the majority of our customers and have put forward an optional demand tariff in this revised TSS. We will continue to refine this tariff to improve cost reflectivity as our customers gain access to more advanced meter technology, and we obtain a greater data set, over the coming years.

3.4.1 Designing the demand tariff

We have designed these tariffs in a similar way to those approved by the AER for the Victorian electricity distribution businesses.[2] Specifically, we:

- Made these opt-in for customers that meet our eligibility criteria (as described in section 4 of our Revised TSS)
- Included fixed charge (c/day) and monthly maximum demand charge (c/kVA) components
- Adopted one peak window for demand charges that covers both peak and shoulder periods (7am to 10pm weekdays) and one off-peak window (every other time). Whilst this window is wider than that approved for Victoria, it does align with our network usage data and our other tariff components.
- For the small business demand tariff, set the demand charge for the peak window to align with our LRMC estimate – to ensure that it is cost reflective
- For residential demand tariff, we set the demand charge slightly below LRMC to encourage customer take up – with the intent to raise this up to LRMC over time to be more cost reflective.
- More on our residual cost allocation to these tariffs can be found in section 4.3.3.
- The customer impact of the opt-in demand tariffs is shown in section 4.4.1.

3.5 Tariff assignment policy

In our initial TSS, we put forward a policy that new connections, solar PV installations and meter upgrades for our residential and small business customers would be assigned to our DBT with the ability to opt-in to a TOU tariff. In its draft decision, the AER did not accept this position as being sufficient to encourage the take-up of more cost

[2] *AER, Final Decision: Tariff Structure Statement proposals | Victorian electricity distribution network service providers— CitiPower, Powercor, AusNet Services, Jemena Electricity Networks and United Energy, August 2016.*

reflective tariffs. Our other stakeholder groups were divided as to whether TOU tariffs should be offered on an opt-in or opt-out basis.

In this TSS we have proposed that new residential and small business connections, solar PV installations and meter upgrades will be assigned to the TOU tariff relevant to their metering technology in the first instance, with the choice for customers to opt out to an alternative tariff should they satisfy the necessary eligibility requirements and choose to do so. The ability to opt out was seen by most stakeholder groups as a satisfactory compromise to mandatory TOU tariff assignment.

In conjunction with our new TOU tariff for small and residential customers with an interval (or higher capability) meter, see section 3.2.4, this will ensure that the bulk of our customers will receive more efficient pricing signals through their tariff than would otherwise be the case. This policy change will also facilitate tariff reform for the bulk of our customers and, as such, is compliant with the Rules. This change has been reflected in our *Policies and procedures for assignment and reassignment of tariffs* which can be found at Attachment 4 to this TSS.

3.6 Specific transitional tariff for some LV business customers

As part of our TSS we have undertaken specific consultation with those parties who will be more significantly impacted by the requirement to move to more efficient pricing. These business customers who have been operating on an existing DBT or TOU tariff, but do not meet the associated eligibility requirements for the tariff going forward, will be required to move to either the appropriate TOU tariff or demand based tariff.

Those customers moving to a TOU tariff will experience minimal impact on their final bills. There is also a small number of customers who will experience bill decreases. We are not proposing a specific transitional period for these business customers.

However, for most customers, the move to a demand based tariff is likely to result in a significant billing increase. To assist customers in managing tariff impacts, we are proposing a specific five-year transitional tariff. This will enable affected customers to gradually adjust to the higher consumption cost and provide time for them to implement any technology and energy saving measures to mitigate the impact. This timeframe is consistent with feedback from our customer consultation.

More detail on this specific piece of work can be found in section 5.

4. DETERMINING OUR PROPOSED TARIFFS

This section provides an overview of efficient pricing, sets out the approach we have adopted in setting our proposed tariffs, and explains how we have complied with the Rule requirements.

4.1 What does efficient pricing look like?

The objective of the new Rule is that the network prices we charge each customer should reflect our business' efficient costs of providing network services to that customer. Specifically, each tariff must be based on the LRMC of providing the service to which it relates to the retail customers assigned to that tariff.

Efficient pricing preserves the LRMC (the cost of consuming or adding one more unit) while also allocating costs that have already been incurred (residual costs) in a way that will provide minimal demand distortion.

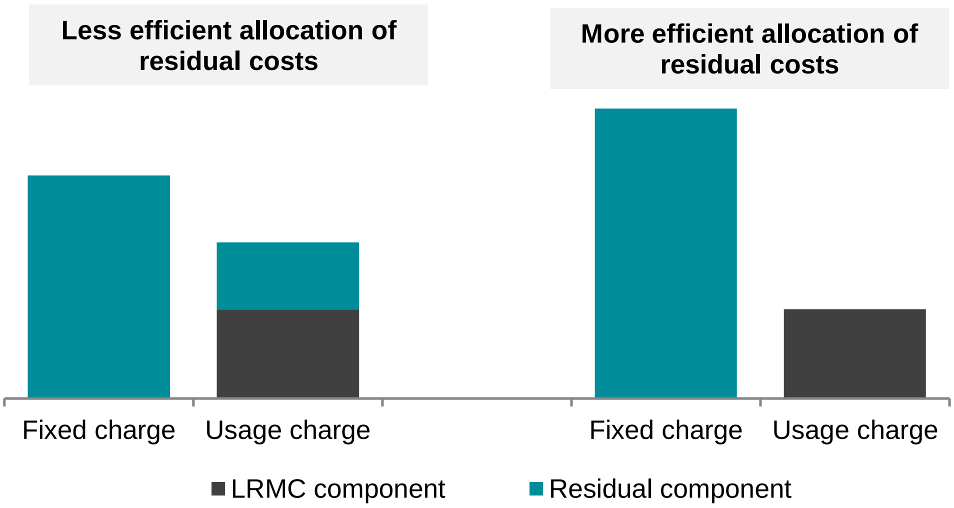
Efficient pricing needs to signal to customers the future network cost of consuming the next unit of electricity. Where there are no network constraints, such as in off-peak times, this cost will be very low. However, if the network is reaching capacity at peak times, the cost to the network of consumers using more energy/demand at that time will grow until it requires us to augment the network to continue to meet demand. These additional costs should, under the Rules, be reflected in the relevant variable usage charge of the tariff structure.

To encourage customers to make more efficient use of the network (that is, make better use of the spare capacity currently available), more efficient price structures would have:

- a larger fixed component, to better reflect the costs of building and maintaining the current network
- lower variable charges (reflecting the cost of future increases to the network from additional consumption).

The difference between inefficient and efficient network pricing is indicated in Figure 4-1 below:

Figure 4-1: Inefficient vs efficient allocation of residual costs



4.2 Overview of the network pricing objective and pricing principles

Clause 6.18.5(f) of the National Electricity Rules states that:

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

This objective seeks to ensure that network tariffs recover the efficient costs of providing distribution network services to customers. To achieve this objective, the Rules set out a number of pricing principles, which we must comply with when setting our tariffs.

Specifically, the pricing principles require compliance with the clauses shown in Table 4-1 below.

Table 4-1: NER pricing principles

Clause	Pricing principle
6.18.5(e)	The revenue expected to be recovered for each tariff class lies between an upper bound being stand-alone cost, and a lower bound being avoidable cost
6.18.5(f)	Each tariff must be based on the *long run marginal cost* of providing the service
6.18.5(g)	The revenue expected to be recovered from the tariff reflects the efficient cost of providing services to customers on that tariff, allows total revenue to be recovered, and does so in a manner that minimises distortions to the price signal for efficient use of the network
6.18.5(h)	In setting tariffs, distributors consider the impact on retail customers of changes in tariffs from the previous regulatory year
6.18.5(i)	Tariffs should be reasonably capable of being understood by customers
6.18.5(j)	Tariffs must comply with all applicable regulatory instruments

4.3 How we have addressed the pricing objective and pricing principles

4.3.1 Revenue for each tariff class lies between avoidable cost and stand-alone cost

Using only a LRMC calculation to set tariffs would not allow us to recover all of our network costs. There are residual costs that are not recovered when prices are set to equal marginal cost. How we recover these residual costs has implications for efficiency. Clause 6.18.5(e) of the Rules establishes limits on the residual costs that can be recovered from any one tariff class, with the revenue expected to be recovered for each tariff class lying between an upper bound – the stand-alone cost – and a lower bound – the avoidable cost.

The **stand-alone cost** of serving a group of customers is the total cost that would be required to serve those customers if we were to the build the network anew to meet their specific requirements. This upper bound ensures that customers in any given tariff class do not pay more as a result of the provision of services to *other* customers.

Avoidable cost is the reduction in cost from any (potentially large) decrease in output. This lower bound ensures that the revenue recovered from a tariff class exceeds the costs that could be avoided were the network not to supply these customers. That is, customers must face a price no lower than the average cost that could be avoided by not supplying them.

So, stand-alone and avoidable cost are important for determining how we recover the residual costs associated with our network. Our methodology for estimating the stand-alone and avoidable cost has not changed from our initial TSS. For completeness, it is reiterated below.

Methodology for estimating stand-alone and avoidable cost

We have used current expenditure as the basis for the estimates of stand-alone and avoidable cost. For example, to assess stand-alone costs for the high voltage tariff class, we have identified the existing assets and operating expenditure that would be necessary to provide services to high voltage customers.

Our approach classifies each of the network's cost categories on the basis of two dimensions, that is:

1. **Whether costs are direct or indirect** – the framework assumes that a cost category is either:
   - 'direct' – that is, the cost can be attributed to a specific group of users and would not be incurred but for those users, or
   - 'indirect' – that is, the cost is common to multiple groups of users.

   As an example, customer metering is directly attributable to individual customers. In contrast, operational expenditure costs are generally indirect, for example the cost of equity raising cannot be attributed to specific customers or customer groups.
2. **Whether costs are scalable or non-scalable** – the framework assumes that a cost category is either:
   - 'scalable' – that is, the cost tends to increase in proportion to the scale at which the service is provided, or
   - 'non-scalable' – that is, the cost is independent of the scale at which the service is provided.

For example, maintenance and repair costs are considered scalable as they are likely to be highly dependent on the physical size of the network. In contrast, equity raising costs are likely to be relatively independent of network characteristics such as the number of customers or maximum demand.

We have then calculated avoidable and stand-alone costs as follows:

> **Avoidable cost** for each tariff class is the sum of all direct costs multiplied by a weighting, which represents the proportion of direct costs that are attributable to that tariff class.

> **Stand-alone cost** for each tariff class is the sum of avoidable costs, non-scalable indirect costs and scalable indirect costs multiplied by a set of scaling factors that vary according to the particular costs in question.

For a more thorough and detailed explanation of the approach we have adopted, please refer to *Attachment 4* of our original TSS - Houston Kemp's *Estimation of Long Run Marginal Cost and Other Concepts Related to the Distribution Pricing Principles*.

We have escalated our stand-alone and avoidable cost calculations for inflation, to ensure they align with the nominal annual prices (and revenues) being proposed in our TSS.

Comparison of revenue and pricing bounds

Table 4-2 sets out our comparison of 2017-18 forecast revenue compared with our estimates of stand-alone and avoidable cost for each tariff class. The results demonstrate that our proposed tariffs satisfy the pricing bounds as required by the Rules.

Table 4-2: Proposed 2017-18 revenue ($M) by tariff class complies with the Rule

Tariff class	Avoidable (lower bound)	Stand-alone (upper bound)	Proposed	Proposed revenue lies between stand-alone and avoidable cost?
LV Residential and Small Business	107	904	692	Yes
Low Voltage Demand	13	811	197	Yes
High Voltage Demand	4	523	47	Yes
Sub Transmission Demand (incl IDTs)	13	133	14	Yes
Unmetered	1	400	9	Yes

4.3.2 Each tariff is based on long run marginal cost

Under the Rules our tariffs must be based on the LRMC – that is, the future cost of adding one more unit of demand or one more connection – ideally, this should comprise the variable component of a tariff. Our tariffs are based on LRMC. Our methodology for estimating the LRMC was accepted by the AER in its draft decision and has not changed from our initial TSS. We have, however, updated our LRMC estimates for inflation and improved data inputs relating to the likelihood of demand occurring in the peak period and our growth capex estimates.

We deemed the average incremental cost method of calculating LRMC as being the most suitable for Essential Energy. Our approach is consistent with that adopted by most distributors in Australia. For a more thorough and detailed explanation of the approach we have adopted, please refer to Attachment 4 - *Estimation of Long Run Marginal Cost and Other Concepts Related to the Distribution Pricing Principles from Houston-Kemp* of our original TSS.

Table 4-3 below indicates our LRMC estimates by voltage level, as well as our aggregated LRMC estimate. These differ from our initial TSS as they have been updated for inflation. Aggregated LRMC means it includes the LRMC from the lower voltages, so that low voltage (LV) includes the LRMC of both high voltage and sub-transmission.

Table 4-3: LRMC estimates

Voltage level	LRMC Estimate ($/kVA pa)	Aggregated LRMC ($/kVA pa)
Low voltage	156.40	328.14
High voltage	138.00	171.75
Sub-transmission	33.75	33.75

Table 4-4 sets out how our proposed tariffs for the 2018-19 year (final year of this period) compare with our estimate of the LRMC. The LRMC has been translated to the specific tariff component for comparison. However, our proposed tariff components for demand based tariffs still incorporate energy charges as well as demand charges. These need to be considered together when comparing to the LRMC.

Table 4-4: LRMC comparison to proposed tariff components by tariff type

Anytime (block) tariffs

Code	Name	LRMC	Proposed 2018-19 DUOS	
		Charge c/kWh	NAC $/year	Energy c/kWh
BLNN2AU	LV Residential Anytime	4.39	306.94	8.421
BLNN1AU	LV Business Anytime	4.39	306.94	11.452

TOU tariffs

Code	Name	LRMC			Proposed 2018-19 DUOS			
		Peak c/kWh	Shoulder c/kWh	Off-peak c/kWh	NAC $/year	Peak c/kWh	Shoulder c/kWh	Off-peak c/kWh
BLNT3AU	LV Residential TOU	16.78	6.87	0.00	306.94	11.112	9.096	2.664
BLNT2AU	LV Business TOU <100MWh	16.78	6.87	0.00	1,710.00	11.418	9.346	4.339
BLNT3AL	LV Residential TOU Interval	16.78	8.52	0.00	306.94	11.668	8.915	2.664
BLNT2AL	LV Business TOU <100MWh Interval	16.78	8.52	0.00	519.78	11.989	9.160	3.905

Demand tariffs

Code	Name	LRMC Demand charge $/kVA/M			Proposed 2018-19 DUOS						
					NAC $/year	Energy charge c/kWh			Demand charge $/kVA/M		
		Peak	Shoulder	Off Peak		Peak	Shoulder	Off-peak	Peak	Shoulder	Off Peak
BLND1AR	Small Residential-Opt in Demand	9.57	9.57	8.20	259.89	1.910	1.185	0.312	4.975		
BLND1AB	Small Business-Opt in Demand	9.57	9.57	8.20	519.78	2.101	1.304	0.343	9.571		
BLND3AO	LV TOU Demand 3 Rate	15.04	12.31	0.00	5,540.74	0.795	0.651	0.180	10.373	9.385	2.258
BLNDTRS	Transitional Demand	15.04	12.31	0.00	3,684.08	7.169	5.868	2.675	4.149	3.754	0.903
BHND3AO	HV TOU mthly Demand	7.87	6.44	0.00	7,219.67	0.579	0.523	0.283	8.948	8.076	2.544
BSSD3AO	Sub Trans 3 rate Demand	1.55	1.27	0.00	6,895.07	0.208	0.120	0.099	3.488	2.487	0.991

4.3.3 Tariffs reflect efficient costs and minimise price signal distortions

Setting our charges based on the long run marginal cost would result in Essential Energy not recovering all of our required revenue. The Rules require us to consider how best to recover these remaining costs – sometimes referred to as residual costs – in a manner that minimises distortions to price signals.

The ability of our tariffs to reflect efficient costs and minimise price signal distortions have been weighed against the ease with which our tariffs can be easily understood by our customers and the impact tariff changes will have on customer bills. We have also considered other applicable regulatory instruments in determining our proposed tariffs. How we have balanced all these requirements is discussed in more detail in Section 4.4 below.

Residual cost allocation

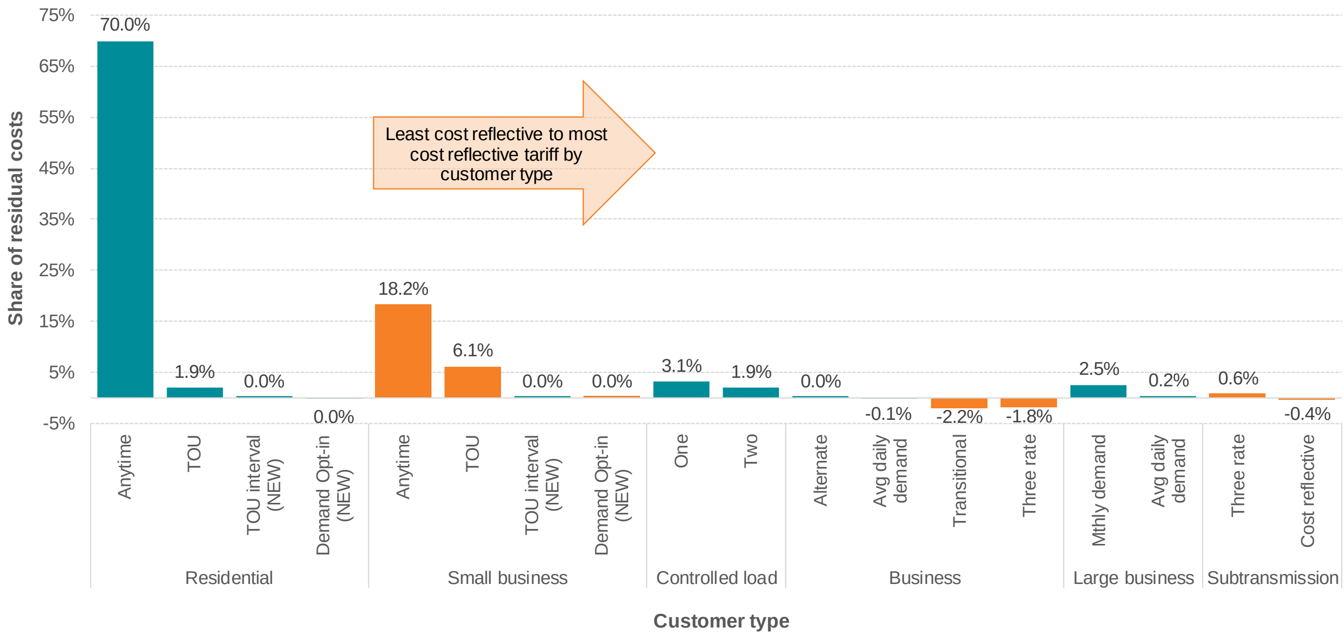
We have sought to allocate residual costs – the difference between LRMC-driven costs and our allowed revenues determined by the AER – in an approach that:

- minimises distortions to efficient price signals
- encourages opt-in uptake of our newly created cost reflective demand tariffs.

This approach means our most efficient tariffs – demand tariffs – most closely reflect their LRMC estimates, while our least efficient tariffs – anytime tariffs – attract a greater share of residual costs.

Figure 4-2 below shows that where the charging parameters are not closely linked to the drivers of Essential Energy's costs (that is, where time of use KVA demand is not the key driver), tariffs have been allocated a higher share of residual costs. This allocation across tariffs provides the least distortion to customers' efficient usage decisions and supports opt-in uptake.

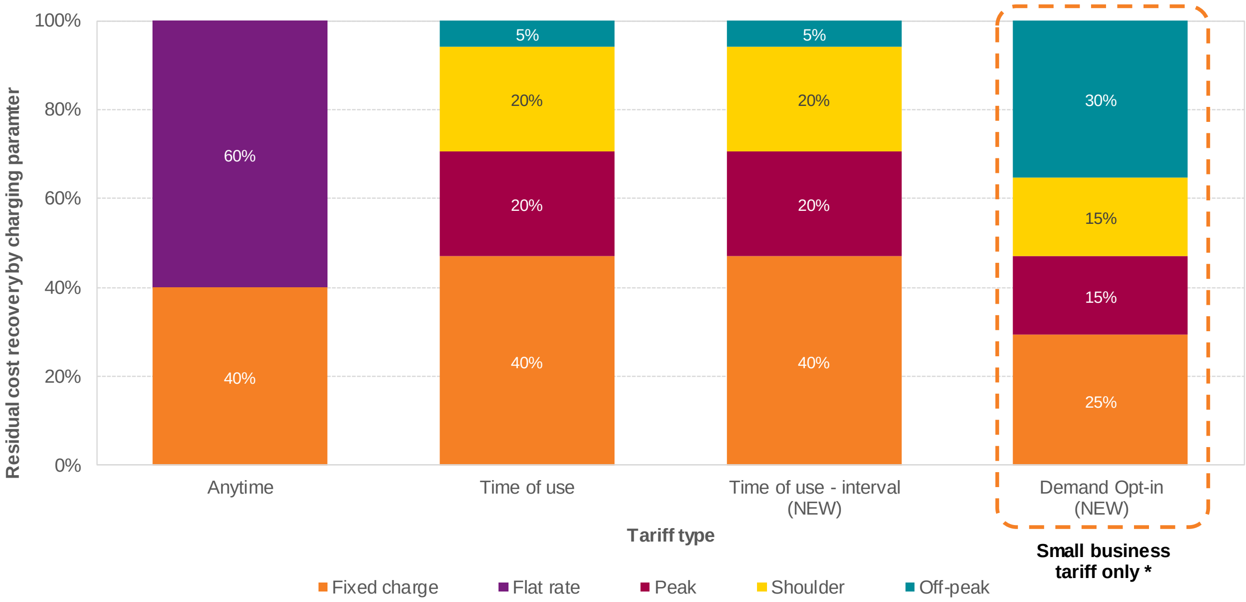
Figure 4-2: Allocation of residual costs between tariff types and customer types



The negative values in the figure above imply that the recovered revenue is less than the LRMC allocation for customers on those tariffs. This outcome is temporary and will be addressed as we transition these tariffs up to cost reflective levels over a period that allows customer impacts to be appropriately managed.

Figure 4-3 below shows that we have continued this principled approach to allocations of residual costs *within tariffs* based on the various charging parameters within each tariff. Charging parameters that are not closely linked to the drivers of Essential Energy's costs, such as fixed and usage charges, have been allocated a higher share of residual costs and the demand tariff does not attract any residual costs. This allocation within each tariff's charging parameters again provides the least distortion to customers' efficient usage decisions.

Figure 4-3: Allocation of residual costs by tariff component for residential and small business customers



It is important to read the allocation of residual costs shown in Figure 4-2 in conjunction with the actual residual dollars allocated to each tariff shown in Figure 4-3. This puts the share of residual costs for the Demand tariff in perspective. These graphs show that most customers are better on the new demand and / or TOU tariffs than the anytime and old TOU tariffs. This aligns with our aim of encouraging customers to take up these tariffs.

It is also important to note that the split of residual costs in the far right is for the opt-in small business demand tariff only. As shown in Figure 4-2, the residual costs are negative for the opt-in residential demand tariff as we are looking to encourage customer take up. Our intent is to transition the charges to more cost reflective tariffs over time.

4.3.4 Treatment of pass through costs

Our treatment of pass through costs has not changed from our initial TSS. For completeness it is reiterated below.

Pass through of jurisdictional scheme costs

Is setting its tariffs, Essential Energy takes into account jurisdictional scheme amounts for approved jurisdictional schemes and ensures that these costs are passed on to customers. Additional requirements such as only 25 per cent of the NSW Climate Change Fund being recovered from residential customers is also adhered to. Adjustments are made for any under or over recoveries made in the previous year.

Pass through of transmission costs

The AER allows Essential Energy to recover the transmission-related costs it pays. Transmission charges are a significant cost component for Essential Energy and are recovered as part of the total network charges levied on our customers.

Transmission related payments are known as TUOS charges and include:

- the cost of transmission-related costs for use of transmission networks owned by TransGrid, Ausgrid and Powerlink
- avoided TUOS payments to embedded generators calculated in accordance with the Rules
- payments for network services to other distributors for inter-distributor transfers.

Transmission charges are not in a form that readily translates into network price structures. Essential Energy translates historical energy and kilowatt demand charges from transmission authorities into equivalent peak, shoulder and off-peak energy rates in order to allocate those charges to the network services tariffs for most customers.

Essential Energy allocates transmission charges to network prices using the following principles:

- The total TUOS allocated to network prices aligns with total expected transmission-related payments to be made by Essential Energy.
- The pass through of transmission charges and the structure of network prices have been aligned wherever possible by Essential Energy.
- Site specific customers have transmission charges allocated in a way that preserves the location and time signals of transmission pricing as per Section 6 of the Rules. These charges are passed through as closely as possible to reflect the manner in which the charges are levied on Essential Energy.
- Network prices for all other customer classes (standard customers) have transmission charges allocated on an average basis, due to the difficulties associated with equitably allocating the general and common service fixed charge as a fixed network access charge, and passing through location price signals which cannot be preserved when the end price is applied to many customers within the network.

For large customers with individual prices, the individual cost of transmission is directly assigned to the customer. The balance is allocated to standard customer classes.

Direct mapping to network prices for standard customer classes has not been possible due to the large fixed transmission charges that cannot be directly included in network price structures for these customers, which typically have a small fixed charge. More importantly, the customer's metering generally does not readily permit it as many transmission charges are levied as demand kW charges. Due to these limitations, it is not possible to pass the same transmission cost drivers through to all customers in the same format as they are provided to Essential Energy.

While allocation of the large fixed charge component is reasonably discretionary, it has been apportioned between customer classes on the basis of their consumption. Allocation to customers in this way is a balance between equity and efficiency. Only the peak and shoulder energy component can be readily passed on to customers through distribution prices.

The transmission charges are allocated on their non-time of use energy, peak and shoulder energy consumption, and/or demand, and are added to the distribution network costs for each customer class. The intention of this mapping methodology is to preserve within the customer's price, to the extent possible, the cost drivers inherent in the transmission charge.

- Non-TOU price – the total transmission charge allocation for the class is divided by the total class consumption and added to the energy rate for the price. Average transmission charges would apply to smaller customers.
- TOU price – the transmission allocation relating to the transmission demand and energy components is divided by the peak, shoulder and off peak consumption and added to the peak, shoulder and off peak energy rates. The transmission allocation relating to the fixed transmission component is added to the TOU energy rates Demand TOU price – the transmission allocation relating to the transmission demand and energy components is divided by the peak, shoulder and off peak consumption and added to the peak, shoulder and off peak energy rates. The transmission allocation relating to the fixed transmission component is added to the TOU energy rates.

The fixed component of the transmission charge was originally largely determined from an 'anytime' energy allocation of costs. This component is apportioned between individual customers and customer classes on the basis of their anytime energy consumption. Allocation to customers in this way is a balance between equity and efficiency. The allocation of the transmission demand charge using peak and shoulder energy is justified on the basis that in the long run, the augmentation of the transmission network – and hence future costs – is related to peak and shoulder utilisation of the network.

4.4 Setting our proposed tariffs

In structuring our tariffs, we have aimed to:

- comply with the pricing objective and principles in the Rules
- ensure simplicity and transparency
- fairly allocate costs between customers based on their share of relevant network costs
- maintain predictable and relatively stable prices over time

> empower customers to make efficient electricity consumption choices

> provide pricing messages to customers that allow them to make appropriate decisions that will, in turn, drive the associated level of network expenditure required.

These goals reflect the requirements of the National Electricity Law (the NEL) and the Rules and reflect our understanding of what customers want from their electricity distributor.

Much of our focus for this TSS has been to build our capabilities to analyse LRMC, and consider how price signals might impact customer use of our network and potentially avoid future network costs. Our customer engagement highlighted that our current tariff structures were well understood, and so these have been largely retained for this TSS with only minor refinements plus some new, more cost reflective and innovative offerings in line with stakeholder feedback and the AER draft decision.

While improving price signals for efficient use of the network has been a major driver in this TSS, managing our customers' bill impact as we transition to more cost reflective tariffs has played a more significant role for our first TSS. Several existing tariffs – for example, those below LRMC and/or with residual costs that could be apportioned more efficiently to further minimise price distortions – will take some time to transition to more cost reflective levels. We cannot transition to true cost-reflectivity across all our tariffs in one step, as the magnitude of some of the required changes would not be consistent with our obligations under clause 6.18.5(h) of the Rules. Instead, as our tariffs become more cost reflective over time and the relative impact on customers' bills declines, emphasis on the customer impact requirement in setting our tariffs will diminish.

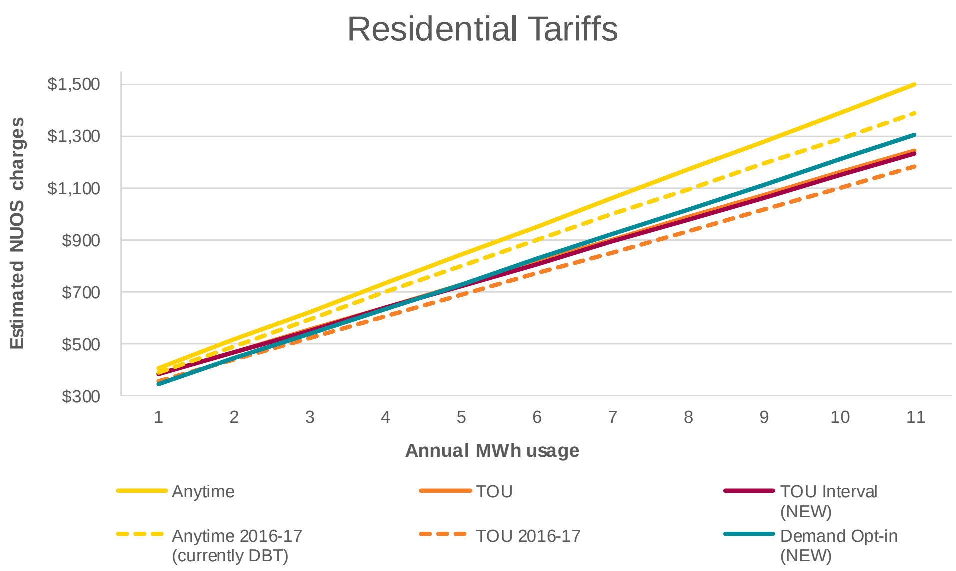
4.4.1 Customer bill impacts

We believe our proposed tariffs strike an appropriate balance between improving price signals for efficient use of the network while taking into account the bill implications for customers.

Residential and small business customers

The differences in 2017-18 residential and small business customer NUOS bills under our proposed tariffs are shown in Figure 4-4.

Figure 4-4: Comparison of proposed 2017-18 residential and small business NUOS bills by tariff



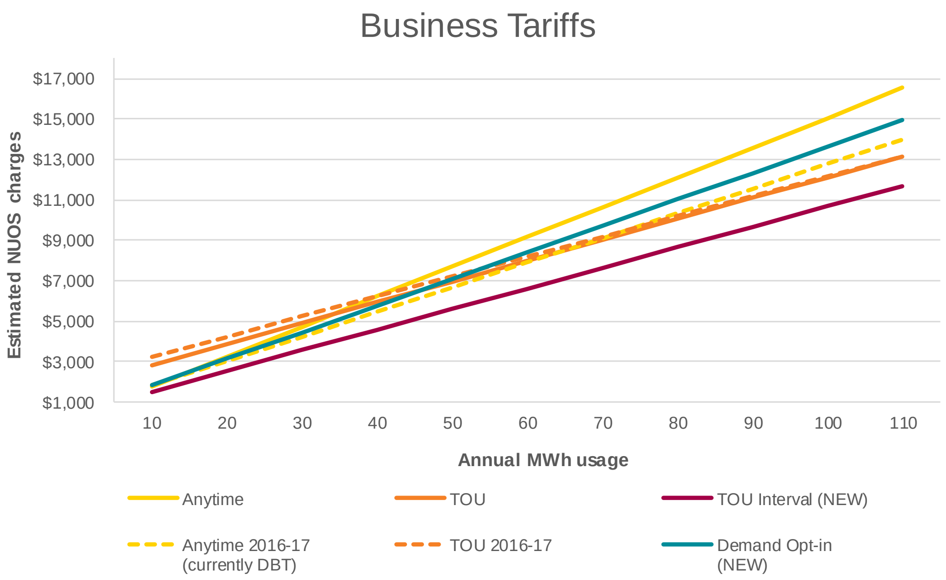
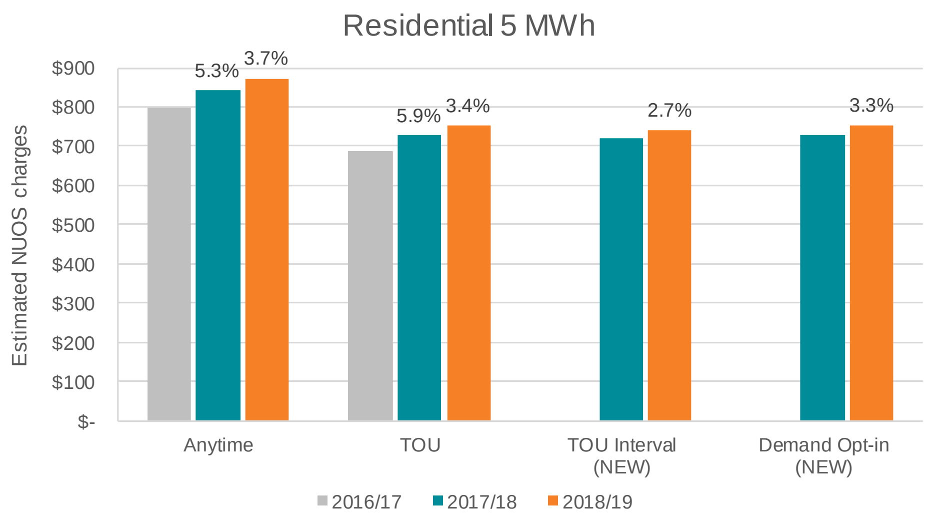
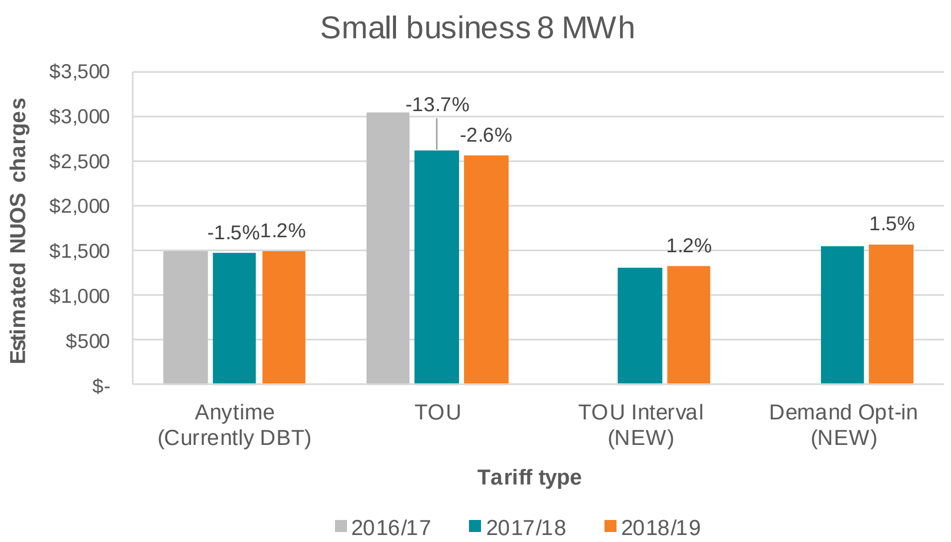
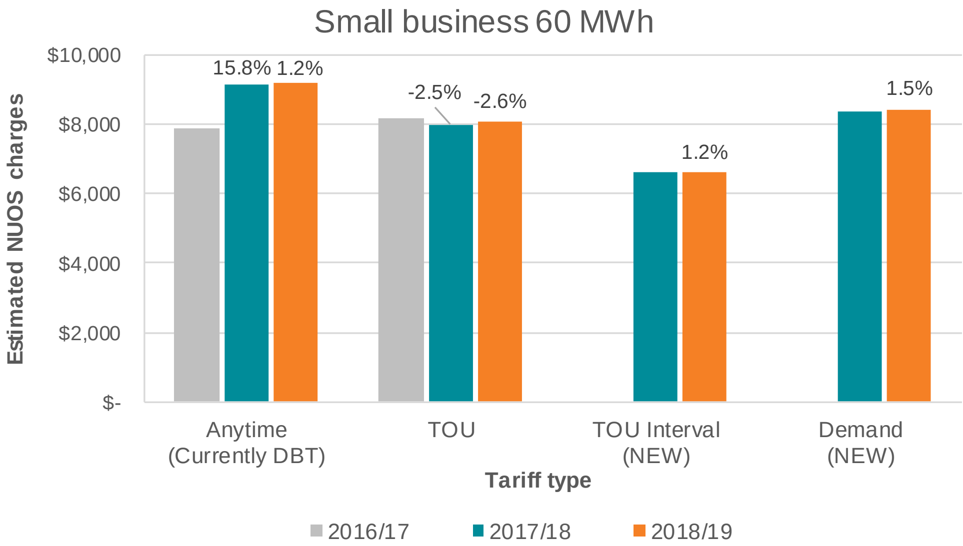


Figure 4-5 below sets out our analysis of NUOS bill impacts by tariff type for an average residential customer and two small business customers for the remainder of this regulatory period.

Figure 4-5: Average residential and small customer annual NUOS bill by tariff type (with year on year change)



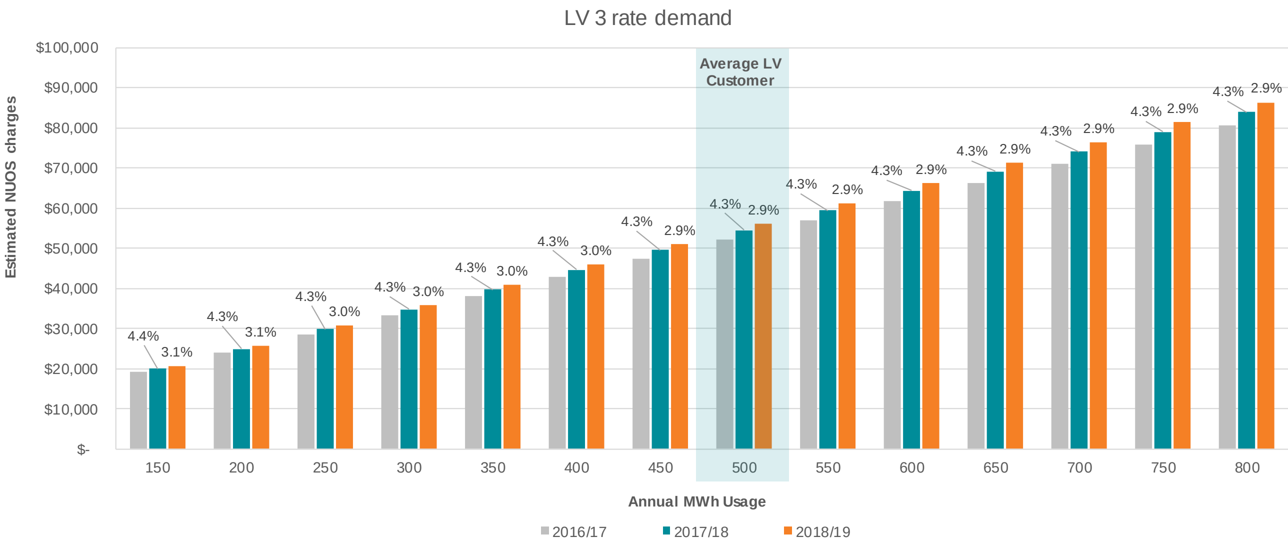


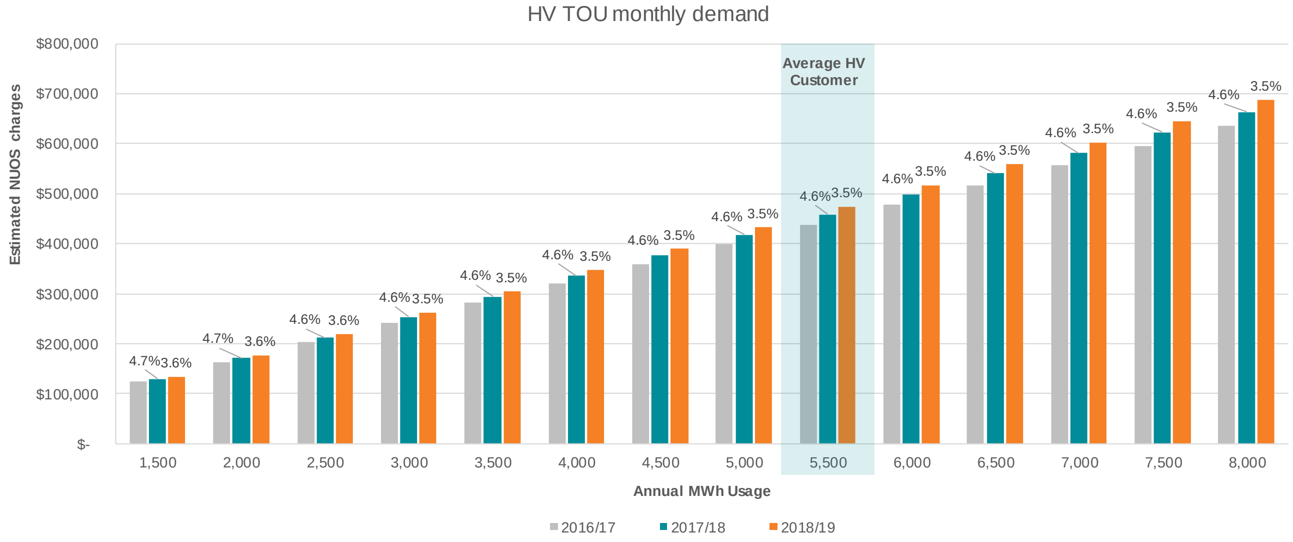


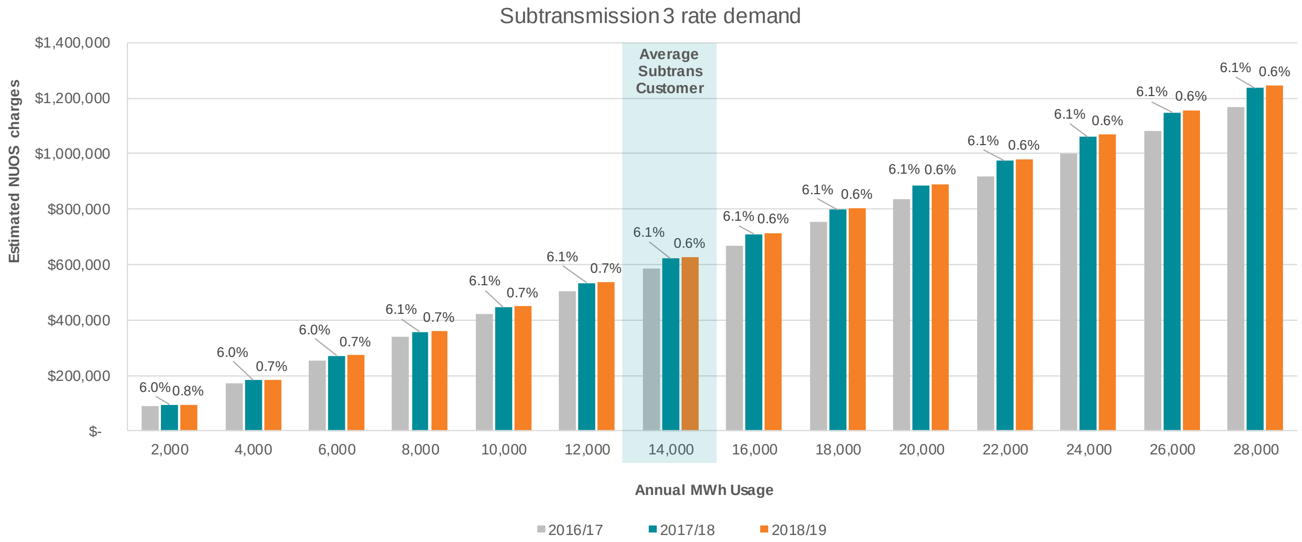
Business, Large Business and Sub-transmission customers

Bill impacts for Business, Large Business and Sub-transmission customer bill impacts are shown in Figure 4-6, though only for the main tariffs employed by those customer groups.

Figure 4-6: Business, large business and sub-transmission annual NUOS bill (with year on year change)







Using other methods of transitioning our tariffs and tariff structures to more closely align with our estimates of LRMC may have led to higher increases in bills for the average customer, particularly in 2017-18.

In summary, we believe that our proposed tariffs are consistent with the distribution pricing principles, as they provide improved price signals for efficient use of the network and balance the bill impact of the proposed changes for customers.

4.4.2 Our compliance with the pricing objective and principles

Our tariffs have been developed in accordance with the pricing objective and principles set out in clause 6.18.5 of the Rules. Table 4-5 below outlines our compliance.

Table 4-5: How we have addressed the pricing objective and pricing principles

	Pricing objective	How we have addressed the objective
	The tariff for direct control services for each of our customers should reflect the efficient costs of providing those services to those customers.	If the variable component of our tariffs is not above LRMC, we are transitioning them to LRMC. Residual costs are being allocated in a way that minimises impact on customer usage decisions.

	Pricing principles	How we have addressed the principle
1.	Revenue to be recovered must lie between the stand-alone costs of serving customers and the avoidable costs of not serving those customers.	> This has been proven in our LRMC model. > In addition, each year our annual pricing proposal will demonstrate that the revenue expected to be recovered from our customers, for each network tariff class, lies between the stand-alone costs of serving customers who belong to that class and the avoidable costs of not serving those customers. > Our expected revenue for each tariff class is estimated to lie between our estimates of stand-alone and avoidable cost.
2.	Each tariff is to be based on LRMC	> *Attachment 7* - Updated Long Run Marginal Cost model sets out the economic model for calculating our LRMC in this TSS and we are transitioning our tariffs towards LRMC. We will look to improve our LRMC approach in future TSS periods – as noted in section 7.3. > The approach which best suits our available inputs and network characteristics is the average incremental cost approach as described in *Attachment 4 - Estimation of Long Run Marginal Cost and Other Concepts Related to the Distribution Pricing Principles from Houston-Kemp* to our initial TSS.
3.	The revenue to be recovered from each network tariff must reflect the total efficient costs of providing services to the customers assigned to that tariff, and in a manner that minimises distortions to use of the network.	> Our proposed tariffs seek to more closely align tariffs to our estimates of the LRMC, taking into account bill impacts on our customers. > If the variable component of our tariffs is not above LRMC, we are transitioning them to LRMC as required in the Rules– in some cases this will take several years. > Residual costs are being allocated in a way that minimises customer impact and improves revenue stability.
4.	Consideration to be given to the impact on customers of changes in network tariffs and tariffs should be designed so that they are reasonably capable of being understood by customers.	> Our proposed tariff structures are largely unchanged from our current structures so they can be easily understood by customers. > The bulk of our customers are residential and small businesses and will move to a simple flat rate tariff. New connections and meter upgrades will see these customers assigned to an appropriate TOU tariff with the option to move to either a flat rate or demand based tariff. > We are publishing brochures to help customers better understand TOU, demand and controlled load tariffs.
5	Tariffs must be readily understood	> Our tariff structures are simple to understand and most have been in place for some time. This makes them easy for our customers to understand. > Our new tariffs have either opt-in or opt-out assignment, thereby supporting our ability to ensure customers understand these tariffs.
5.	Network tariffs must comply with any jurisdictional pricing obligations imposed by state or territory governments.	> Our proposed tariffs take into account adjustments associated with the recovery of jurisdictional scheme costs – see section 4.3.4.

4.5 Customer transition strategy

The tariffs (and tariff structures) proposed in this TSS more accurately reflect the forward looking costs our customers impose on the network. Although some variable components of our tariffs (energy and/or demand) are not covering the LRMC, we will transition them up to LRMC levels over a period of time to limit the immediate impact on customers. At this stage we are also proposing to increase the range between our peak and shoulder rates. As such, we believe our proposed tariffs will deliver efficient price signals to customers and are compliant with the Rules.

Stakeholder feedback received in preparing our initial TSS indicated a timeline transition preference of three to five years. However, we will take a longer period to transition to efficient pricing levels. This is partly a reflection of the compilation of our existing tariffs, but is also directly attributable to the available metering technology in our network area today. As more advanced meter technology is rolled out across our network our ability to reflect our network costs more accurately in the tariff structures we offer will improve.

As mentioned in section 3.6, we are undertaking a specific transitional program for our LV business customers who are currently on DBTs or TOU tariffs, but who do not meet the eligibility requirements for this tariff or its counterpart going forward. These customers require transition to either the appropriate TOU tariff or demand based tariff. We are not implementing a specific transitional period for those business customers that will experience a bill decrease, nor those who need to move to a TOU tariff, as they will experience only a minimal impact on their final bills.

However, to assist customers in managing adverse tariff impacts, we are proposing a specific five-year transitional demand tariff. This will enable affected customers to gradually adjust to the higher consumption cost and provide time for them to implement any technology and energy saving measures to mitigate the impact. This timeframe is consistent with feedback from our customer consultation.

More detail on this specific piece of work can be found in section 5.

4.6 Alternative Control Services

Our Alternative Control Services (Type 5 and 6 metering, public lighting and ancillary network services) are incurred by individual customers. Our approach to determining Alternative Control Service charges was detailed in our regulatory proposal for the 2014–19 regulatory control period.

Our AER-approved cost reflective prices for these services for the 2017–19 TSS period are set out in the indicative pricing schedule at Attachment 5 - *Alternative Control Pricing Schedule* to this TSS.

5. TARIFF CHANGE PROGRAM

In accordance with the requirements of the final Rule and in line with our Policy for Tariff Assignment and Reassignment, we carried out a review of customer electricity loads to ensure that they were assigned to the correct tariff. This review identified a number of LV business customers using greater than 100MWh of electricity per annum who are currently on an incorrect tariff and who need to be moved to either a demand or TOU based tariff. As a result of this review we have initiated a project to consult with affected customers and to develop a collaborative strategy to move them to tariffs that provide more efficient pricing signals from 1 July 2017.

5.1 Overview

As at 30 April 2016, we had around 2,300 business customers currently on a DBT or TOU tariff that do not meet the associated tariff eligibility criteria. Of these 2,300 businesses:

- 1,300 need to move to an appropriate TOU tariff – billing impact is negligible
- 102 need to move to a demand tariff, but will be better off
- 4 need to move to a demand tariff and will be worse off
- the remaining 225 customers need to move to a demand tariff, but do not currently have the interval metering required to assess the associated billing impact.

We will move the 1,300 customers who need to move to a TOU tariff and the 102 customers that will be better off under the correct demand tariff to the appropriate tariff on 1 July 2017, unless they elect to move earlier. Consultation with our stakeholders supports this approach.

For the remaining impacted customers, we are proposing the introduction of a specific transitional demand tariff that will allow for the transition to the full demand tariff over a five year period. The 224 customers who do not currently have adequate metering technology will move to the appropriate level of the transitional tariff in the year that they upgrade their meter. For example, if a customer upgrades their meter on 1 December 2018, they would forego the first year's transitional step and be assigned to the transitional tariff at the transitional rates applicable to the 2018-19 pricing period.

The number of customers transitioning to an appropriate tariff is likely to be lower by 1 July 2017, when the tariff changes required by the TSS come into operation, as:

- We expect customers for whom moving to the correct tariff will be favourable to elect to change tariffs earlier.
- Retailers are actively targeting these customers and encouraging them to install solar PV as a means of lowering their consumption below the threshold that would otherwise require them to move to the appropriate tariff.

We will recheck customer consumption levels before 1 July 2017 to determine the final number of customers who will require assignment to the new transitional tariff.

5.2 Initial customer notification

In July 2016, we wrote to around 1,100 customers consuming greater than 160MWh in the past 12 months but who are currently incorrectly on either a DBT or TOU tariff, to advise them that they need to move to a more appropriate demand based tariff from 1 July 2017. Similarly, we wrote to around 1,300 customers who consume greater than 100MWh but less than 160MWh per annum and who are currently incorrectly on a DBT to advise them that they will be moved to a TOU tariff.

For most customers, the move to more appropriate cost reflective tariffs will mean that they will see an increase in their annual bills. The letters outlined the reasons why customer tariffs need to be changed and also the consultative approach we planned to take to reduce impacts on customers.

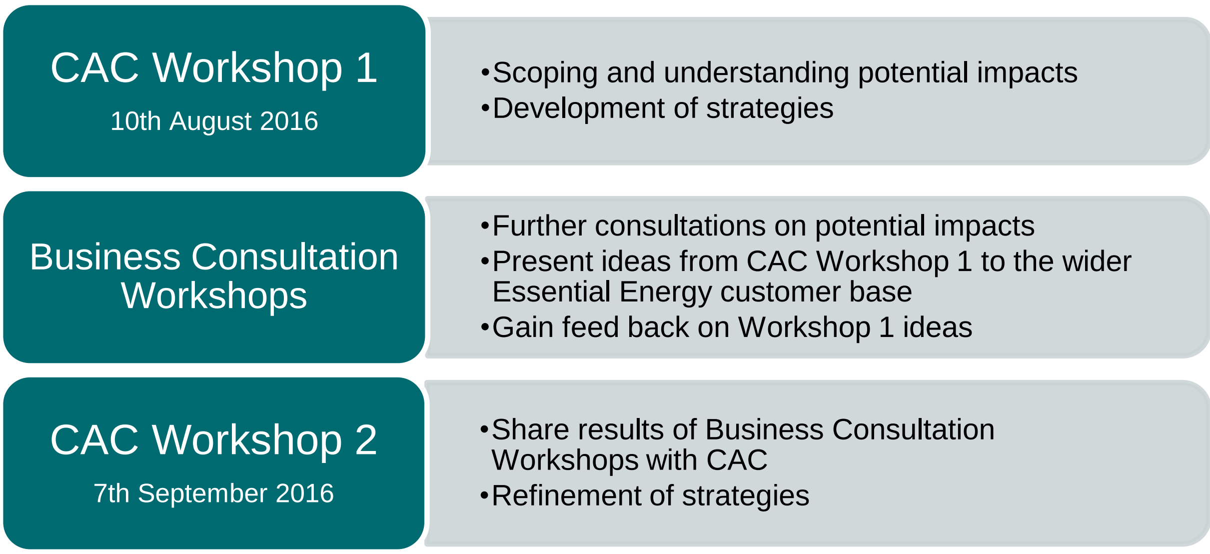
5.3 Consultation process

Essential Energy engaged the services of an independent market research company (IPSOS Australia) with expertise in customer consultation and focus group program management to facilitate the consultation process. They developed a consultation plan which we reviewed and approved. Figure 5-1 provides an overview of the process.

A Customer Advisory Committee (CAC) was formed to help develop the strategy for tariff change. It comprised members of the peak bodies and businesses that represent the industries and sectors impacted by the tariff changes. The role of the CAC was to advise on how changes could be implemented so that impacts to customers can be mitigated as far as possible.

After formulating a draft strategy in the first CAC workshop, a series of Business Consultation Workshops were held with customers in various locations, as well as a number of online workshops and one-on-one discussions. The CAC members then reconvened and feedback from these workshops was presented to them. The potential strategies were then refined and will be used to develop an implementation plan for the tariff changes. The feedback from customers and proposed solutions are discussed in section 5.4 below.

Figure 5-1: Overview of consultation process for the tariff change project



5.4 Customer feedback

Table 5-1 summarises the key issues and concerns raised by customers in the Business Consultation Workshops.

Table 5-1: Customer feedback from business consultation workshops

Issue		Details
Financial impacts	Inability to pass costs on to customers	> Most organisations will not be able to pass on costs > Many locked into long term fixed contracts with customers > Price increase could risk competitiveness of their business
	Costs associated with meter changes	> Unclear about requirements for changing meters > Unaware of cost associated with it > Frustration that they should have to pay for this on top of increased bills
	Costs of engaging energy consultants	> Interest in energy audit depends on cost to business > Concern that this is an opportunity for 'cowboy' operators > Support from Essential Energy would be well received
	Increased costs of peak use; and limited scope to change consumption patterns	> Most feel they have limited scope to change consumption patterns > More scope for change among those who have not previously had energy audits (mainly small businesses)
	Increased costs may result in staff reductions and other cost cutting	> May have to cut staff hours, staff numbers, reallocating budgets, cuts to services, operating at a deficit > Many unable to predict wider impacts until impact is known

Issue		Details
Communication and engagement	Some difficulty in understanding the detail and impact of the change	> No clear information about financial impact of new tariffs and action required > Lack of information to date is seen as "disrespectful"
	Letter is not sufficient to raise awareness of the changes	> Some customers do not recall receiving the letter > Letter alone is not enough to fully and effectively communicate the changes
	Does not highlight the scope of the impacts	> Unable to predict impacts or make plans as do not have enough information (especially financial) > Requested exact figures for their organisation
	Industry associations don't know extent of impacts	> Also unable to predict impacts or make plans as do not have enough information
Energy usage and efficiency	Demand tariff: Brief spikes in electricity to lead to peak rate for full month	> Demand tariff seen as particularly unfair > Do not understand why spikes in demand should incur such high costs
	Some industries have difficulty reducing usage	> Service providers (e.g. Councils) have little scope to change usage patterns. > High demand customers have no ability to reduce the peaks in usage, e.g. irrigators
	Concern reductions in usage won't be recognised for 12 months	> Interest in new tariffs being reassessed if they make changes to energy use before July 1st
Solar	Those with solar were unaware of tariff changes when it was installed	> Business case for solar power will now change, may not have installed if known
	Some unable to reduce consumption through solar power	> Many now see solar or diesel as more attractive > However, some businesses would not be able to use solar without battery solution
Metering	Unclear who is responsible for ensuring meters are changed over	> Lack of understanding of costs of new meters > Lack of understanding of requirements and role of retailer > Welcomed an explanation of requirements and costs from Essential Energy
Retailer	Unclear how retailers will be involved	> Most do not see the retailer playing a significant role. Request for consistent information from all parties. > Important for retailers to help explain the role of Essential Energy vs. the retailer
Timing	Concern that 1 July 2017 is not enough notice to prepare for the changes	> Some were satisfied with the notice period provided > However, concern among others about time left to fully understand the changes and make plans > Councils and Not for Profit organisations in particular found the timing problematic due to long term planning and funding cycles > Changes required may be significant and need a longer lead-in time

Table 5-2 sets out the solutions proposed by the CAC in the first workshop and summarises feedback on these from customers in the Business Consultation Workshops.

Table 5-2: Customer feedback to solutions proposed by the CAC

Proposed solutions by CAC	Customer reactions to proposed solutions
Information and engagement strategies	
> Follow up phone call > Additional letter/email with FAQs > Account Managers to be provided to each customer	> Want recognition of the significant impacts of the changes > Account managers a popular idea: want personal contact with Essential Energy, and tailored advice. > Online information and tariff calculator also welcomed > Historical consumption data could be useful, but only if it is in a useful format
Essential Energy to collaborate with Retailers	
> To help customers understand the changes > To clarify requirements for meter changes	> Customers did not see a significant role for their retailer (however, many did not understand that the retailer is responsible for providing them with their new meter)
Energy audits	
> To be subsidised by Essential Energy > Alternatively, energy consultants to be recommended to customers	> Very popular idea, especially among smaller businesses which had not had energy audits in the past and had limited resources for energy management > Many wanted guarantee that cost of audit would be recouped by reductions in bills (otherwise subsidy would be critical)
Industry specific tariffs	
> Industry specific tariffs	> Popular among those who cannot pass costs on to customers > Concern from others over fairness and 'playing favourites'
Additional tariffs	
> Additional tariffs for 100-160MWh customers	> Most lacked the knowledge to be able to comment > 160MWh too low for demand tariff, suggested additional tariff for 160MWh-400MWh customers
Changing trigger for demand tariff	>
> Demand tariff to be triggered by average of peaks instead of a single peak	> Positively received > Also suggested review system for unusual peaks (e.g. if it occurred as a result of a blackout), and warning when usage peaked
Transitional tariffs	>
> Gradual transition to a full demand tariff	> Popular idea and potentially very helpful to allow organisations time to implement plans to manage the changes > Many customers lack information needed to judge how effective this could be, and what the time period for the transition should be
Hardship programs	>
> Hardship support programs for certain customers	> Typically, not supported by customers, except those facing the prospect of going out of business as a result of the changes > Some support for public sector and Not for Profit organisations to be eligible for hardship support
Frequency of assessment of usage and tariffs	
> More frequent assessment of usage and tariffs (e.g. every 1-2 months rather than every 12 months)	> Supported by customers. > Idea of rewarding changes in energy use, and not having to wait 12 month for an assessment, is popular
Role of peak bodies in the process	
> Peak bodies to play a role in the process, after receiving more information from Essential Energy about the organisations impacted	> Many customers could not see how peak bodies could play a role. > Some saw any additional support as beneficial, and wanted Essential Energy to engage with their peak body

5.5 Essential Energy's response to customer feedback and solutions proposed by the CAC

Information and engagement strategies

We recognise the need for, and importance of, increased engagement and communication with customers about the changes. Specific Account Managers are not a feasible solution for us given how resource intensive this would be. We will however, ensure that there will be a small team of people in our call centre specifically trained to deal with this matter and who can discuss the technical details with customers. We will also aim for customers to deal with the same person each time they contact Essential Energy on the matter.

Essential Energy to collaborate with retailers throughout the change process

We cannot control how Retailers operate but we will make every effort to engage with Retailers and urge them to be consistent and fair regarding metering. We will encourage customers to negotiate with their Retailers to ensure they get the best outcome possible for their business.

Energy audits

Essential Energy does not have experience in energy audits. There may be potential for subsidised energy audits but funding would have to come from a source other than Essential Energy. There is a risk in providing lists of energy auditors to customers as we cannot verify their reputations. However, we could direct customers to the Office of Environment and Heritage (OEH)[3] or other relevant agency. We can also provide de-identified disaggregated interval data to peak bodies for their industries (in Excel/CSV format). However, it will not be aggregated.

Alternative tariffs and changing trigger for demand tariff

Industry specific tariffs will not necessarily be beneficial to some sectors such as primary industry. We are unable to subsidise some customers over others, so this option will not be progressed. Demand tariffs have been created for smaller users in our revised TSS.

Transitional tariff

A transitional tariff is included in the revised TSS for those customers who are being moved to a demand tariff and who will be worse off because of this. We asked our stakeholder groups for feedback on potential impacts and suggestions for an appropriate transition pathway. All groups believed a transition period was necessary for the 73 negatively impacted customers and the 22 unknown but potentially impacted customers to alleviate bill shock and allow customers time to adapt to the change in pricing. A minimum of five years was suggested by the most impacted stakeholder group.

More details on our proposed transitional tariff are given in section 5.7. A final decision by the AER on a transitional tariff will not be given until February 2017, but we will be advising customers what the transitional tariff may look like prior to this, with the caveat that it is subject to AER approval.

Hardship support programs

We will not pursue the possibility of running a hardship support program as there has been a consistent lack of support for this from the consultation groups. A similar program was also put forward under the guise of a social tariff by SA Power Networks in its 2015-16 annual pricing proposal. This tariff was rejected by the AER and the decision upheld on judicial review by the Federal Court of Australia. There are already several hardship programs available across the market and Retailers have hardship programs for small businesses.

More frequent assessment of usage and tariffs

If a customer can demonstrate that they have made necessary changes and decreased their electricity consumption below the relevant threshold, we can consider changing their tariff in accordance with our tariff reassignment conditions. We will also assess the potential for rebates for periods of time during which a customer is unfairly charged. This will be done on a case by case basis, in response to a customer requesting a review of their circumstances.

---

[3] http://www.environment.nsw.gov.au/business/energy-efficiency-expert.htm

Peak bodies to play more of a role

We have relationships with a number of peak bodies and are committed to developing better customer engagement.

5.6 Next steps

It is clear from the consultation process that we need to increase communication, education and support for affected customers. We will develop a plan to ensure that the proposed solutions arising from the consultation process are further investigated and implemented where possible. This TSS includes a proposal for a transitional tariff to limit the impacts for customers of moving to a demand tariff. We will continue to engage and communicate with customers throughout the process.

5.7 Transitional approach

Without our proposed transitional tariff, many of these customers would face immediate bill shock. As previously mentioned, we do not have data for all impacted customers, as 225 customers do not currently have the interval metering required to assess the associated billing impact. However, based on data for the 837 known impacted customers, 432 customers (52 per cent) would face bill increases of 20 per cent or more.

Figure 5-2 and Figure 5-3 below highlight the spread of estimated billing increases for these 837 customers without the implementation of a transitional tariff.

Figure 5-2: Expected annual bill increase in dollars without a transitional tariff

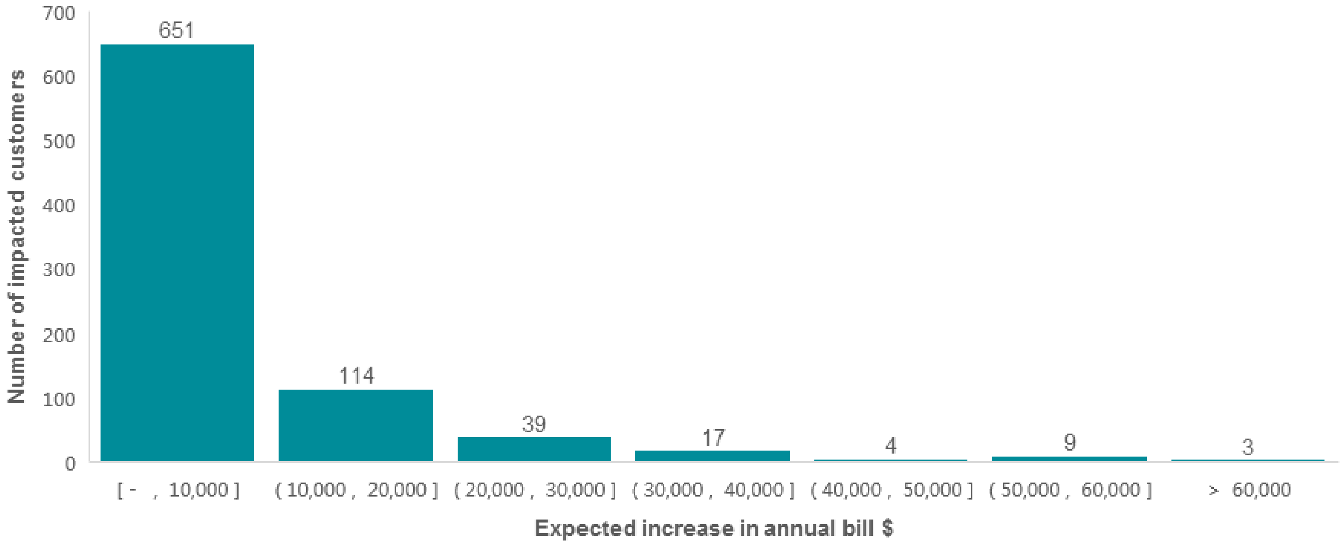
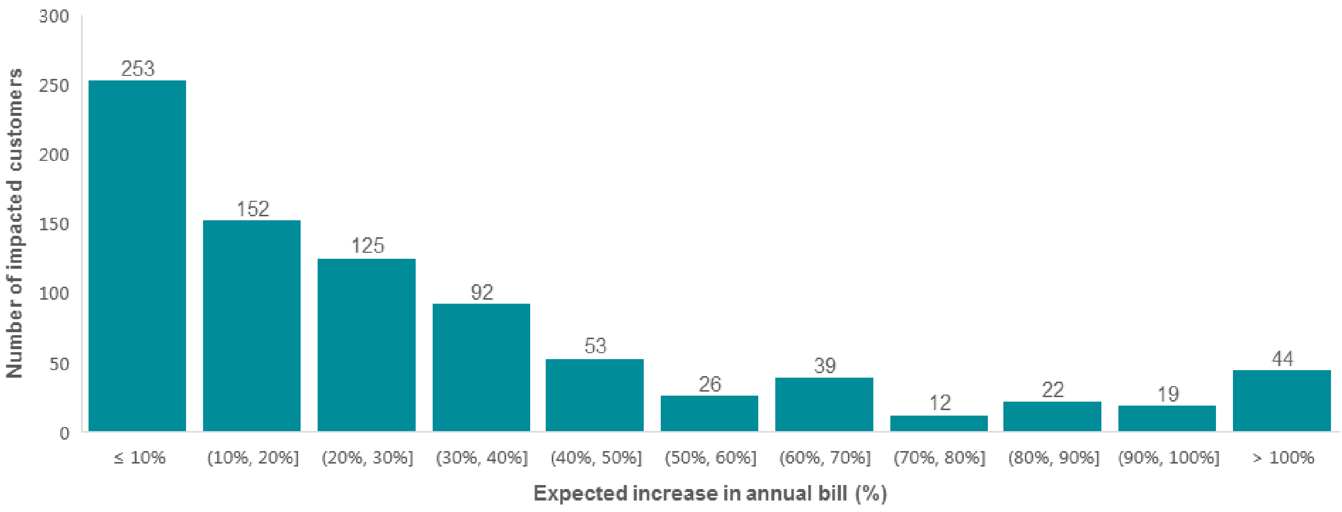


Figure 5-3: Expected annual bill increase in percentage terms without a transitional tariff



Our transitional tariff will phase the impact of these increases over a five year period. This means that in the first year of our transitional tariff, only 53 customers (six per cent) will experience a bill increase of more than 20 per cent, as shown in Figure 5-4 and Figure 5-5 below.

Figure 5-4: Expected first year bill increase in dollars for customers worse off under the transitional tariff

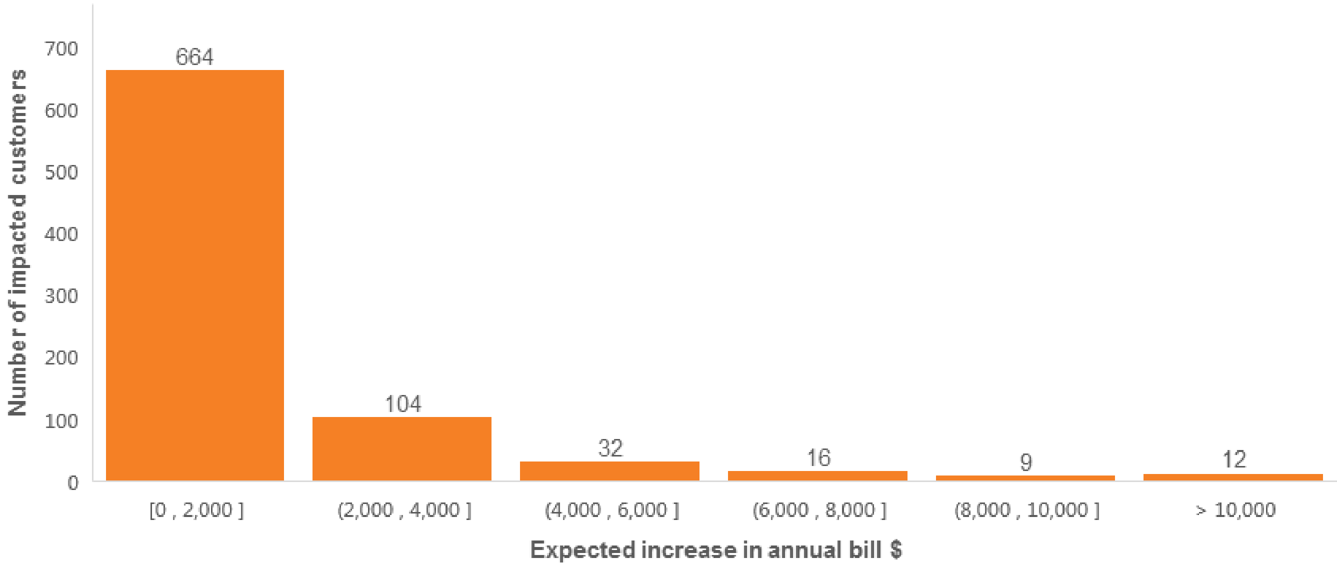
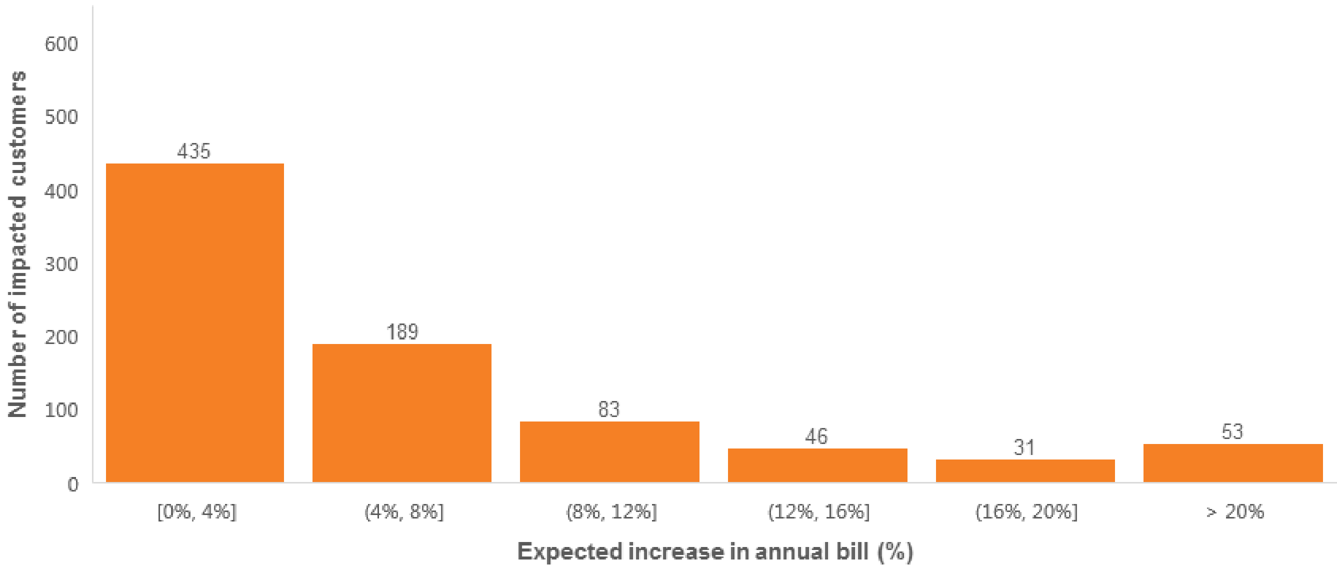


Figure 5-5: Expected first year bill increase in percentage terms under the transitional tariff

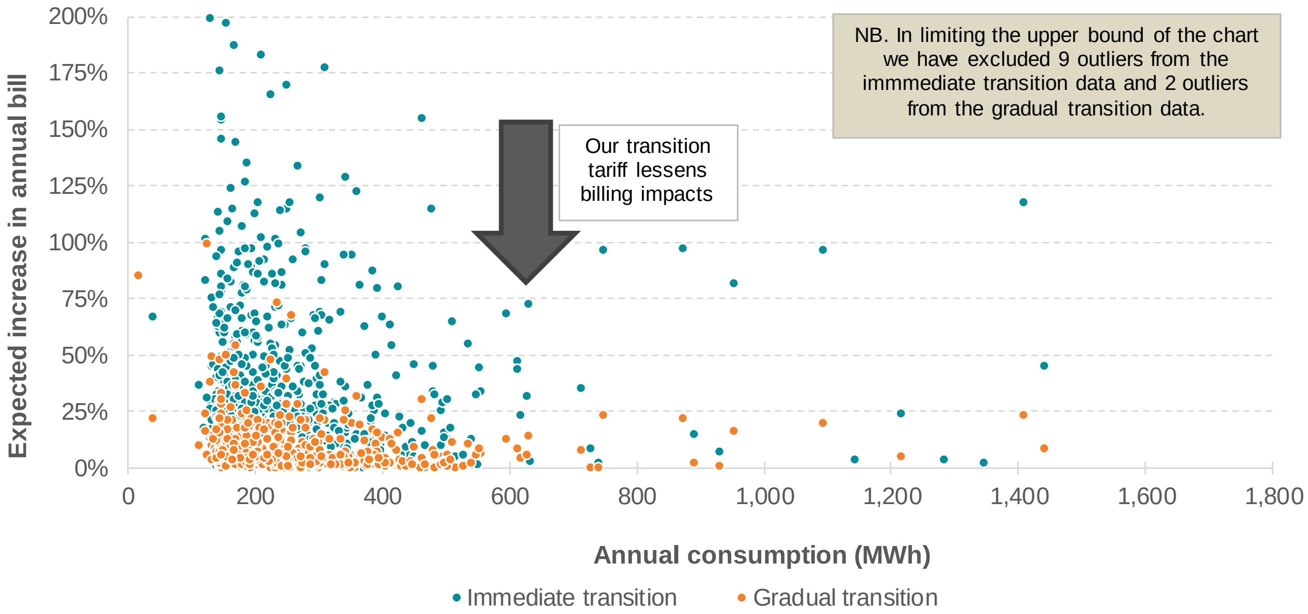


Our transitional tariff will slow the billing impacts on these business customers, allowing them time to adjust to the additional costs as well as potentially introduce efficiency measures or alternative solutions like solar PV or improving power factors.

As the tariff comprises several tariff components to be phased in over five years, the impact on each customer in each year will vary depending on their demand and usage profile. That is, one customer may experience a bill decrease in the first two years, but bill increases in the subsequent years, where another will experience consistent bill increases in each year. Every customer's profile is different and it is impossible to design one tariff that will work in the same manner for each customer.

Figure 5-6 below demonstrates the spread of worse-off customers by consumption level and increase in the first year's bill under both an immediate transition to the appropriate tariff and under our proposed transitional tariff. It is clear that our transitional tariff is lessening the billing impacts for these worse-off customers.

Figure 5-6: Worse-off customers based on first year billing

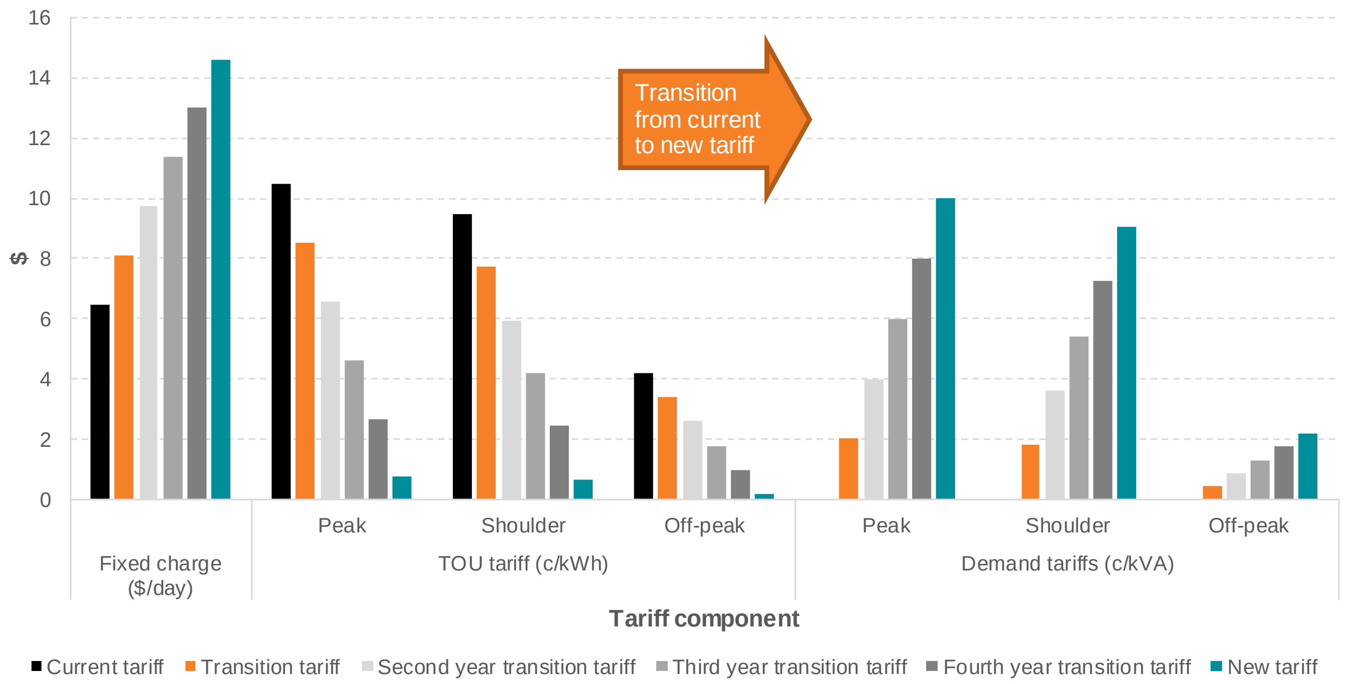


The proposed transitional tariff for these customers is identical in structure to the Time of Use demand three rate demand tariff available to other Business customers. However, the weighting of the components varies. The application of this tariff will ensure we adhere to the pricing principles in the Rules by transitioning these customers to a demand based tariff over five years to limit bill shock.

Establishing a specific tariff for these customers will also eliminate transitional pricing errors as there will be no reliance on manual intervention in the billing process.

An overview of the proposed tariff transition path over the five year period is shown below.

Figure 5-7: Transitional demand tariff proposed transition path



6. HOW OUR TARIFFS INTERACT WITH OUR DEMAND MANAGEMENT STRATEGY

6.1 How demand management works

The network's capacity to supply load or absorb generation at any point can be constrained either by the current rating of elements in the supply path or by unacceptable voltage conditions for customers. Traditional network solutions involve augmentation to increase the supply capacity through upgrading existing infrastructure or providing additional infrastructure to reduce the impedance of the supply path. Demand Management (DM) and Non-Network Alternatives (NNA) offer substantial potential to achieve the power quality and capacity levels required of the electricity network at reduced costs compared to traditional network augmentation.

Essential Energy continues to refine the application of demand management options and monitor emerging and innovative demand management applications to continue capturing benefits for both customers and stakeholders. This approach ensures we effectively utilise our resources and expenditure with the aim of delivering a safe and reliable energy supply now and into the future.

The need to better manage demand led to the network driven creation of a Controlled Load System for hot water storage systems. Conversion of hot water storage systems over to Controlled Load results in a net benefit to both customers (through access to much lower off-peak tariffs) and the network (the network controls the load so it can cap network demand as required). Hot water storage units on Controlled Load are affordable for customers and provide a much lower overall cost solution than the alternative of augmenting the network.

Essential Energy's Demand Management programs during the current regulatory period have included both the continuation of existing programs and the development of new initiatives.

Existing programs included:

- Ongoing optimisation of power electronic equipment control and application in field trials for energy storage, reactive power and embedded generation to further enhance the cost effectiveness of such technology in business as usual applications to addressing network constraints. Continued development in this technology may lead to mutually beneficial outcomes for both consumers and networks through increased penetration of renewables and mitigation of the adverse effects on network power quality currently experienced.
- Evaluation of conservation voltage reduction technologies, allowing a reduction in both consumers' energy and peak demand.
- Evaluation of mid-sized static synchronous compensator for use in power factor correction, as a relatively simple alternative to traditional network augmentation but with major improvements to power quality over existing power factor correction technologies.
- Development of optimisation techniques for existing and future field based power factor correction, ensuring Essential Energy is maximising the value of equipment currently being installed on the network and into the future.

While new Innovative Demand Management developments during the regulatory period included:

- Constraint and Growth mapping, which aims to promote non-network proposals from a variety of proponents.
- Creation of standards, guidelines and specifications for field based switched capacitors, which will be used to approach the market to source and guide the application of such cost effective technology for business as usual demand management applications.
- Based on the growing interest in battery storage technology behind the meter, trialling of connection standards, metering and tariffs, with the aim of guiding the uptake of battery storage while ensuring such technology does not negatively impact the network resulting in costly network expenditure. In addition, Essential Energy is currently exploring the possible value battery storage technology can provide through deferring or avoiding network expenditure and appropriate signals required to yield such potential.
- Exploring least cost options. Due to the varying customer density of Essential Energy's network across diverse terrain, there are areas of Essential Energy's network that result in a high cost to serve very

few customers, causing cross-subsidisation of network tariffs. These parts of the network (typically fringes of the current network) present potential viable areas to transfer customers to an off-grid solution and decommission network assets. Essential Energy is currently exploring the practicality of implementing such least cost solutions within these areas triggered by network investment. This would minimise network costs which is in the long term interest of all customers.

> Initiation of Load Control System Optimisation studies for problematic areas of the network, which aims to further improve the cost effectiveness of the load control system and identify least cost alternative load control technology compared to traditional load control equipment.

6.2 Interaction with our tariff strategy

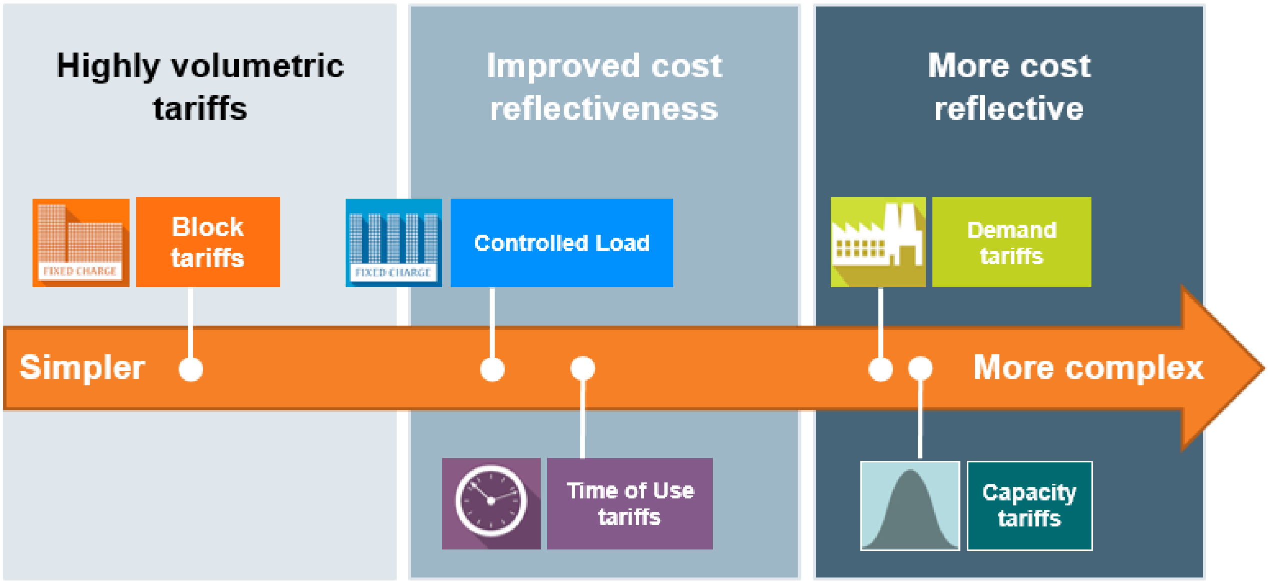
Demand management is closely linked to tariff structures. Clear price signals allow customers to make choices (price versus convenience) as to when to use electricity. In Figure 6-1 below, we attempt to show how different tariff structures align to customer price signals.

> On the left hand side, simple to understand block tariffs are highly correlated with customer usage but bear little correlation to cost-reflectivity. As a result, they send no price signal to customers.

> The middle ground is a trade-off between complexity and cost reflectivity. Customers have adequate price signals to make choices that are somewhat cost reflective.

> On the right hand side, capacity based tariffs are very cost reflective as they are highly correlated with network demand. They are, however, far more complex for customers to understand and appropriate technology is required if customers are to be able to adequately react to price signals.

Figure 6-1: Tariff complexity and price signals for customers



In terms of Essential Energy's current tariff offerings:

> The bulk of our customers, residential and small business customers, are currently on volumetric based tariffs – our current DBT and our proposed flat rate tariff. These tariffs are simple to understand, but not cost reflective against a LRMC methodology.

> We offer Controlled Load tariffs to our residential and small business customers. Controlled Load tariffs allow Essential Energy to control the use of certain household appliances and they are only operated at off-peak times. Customers pay lower tariff rates for appliances that operate under Controlled Load. These tariffs remain easy to understand and send a clearer price signal so are somewhat cost reflective.

> Our TOU tariffs are also fairly simple to understand and send a clearer price signal to customers as they are somewhat cost reflective.

- Our demand based tariffs are our most difficult tariffs to understand, but also are our most cost reflective tariffs as customer usage is highly correlated with network demand pressures.

Our proposed change to our residential and small business tariff assignment policy, whereby new connections solar PV installations and meter upgrades will be automatically assigned to the relevant TOU tariff with the ability to opt out to a flat rate tariff or demand tariff, will further improve the take-up of our more cost reflective tariffs while also sending clearer price signals to customers (see section 3.5).

Planned changes to our charging windows (see section 3.2), where a customer has the appropriate meter technology, will also enhance our ability to control network demand by better signalling to customers the network costs created by their demand pressure.

7. FUTURE TARIFF STRUCTURES AND PRICING DIRECTIONS

7.1 Changes to this TSS

We can seek amendments to an existing TSS for events that occur beyond our reasonable control and that could not have reasonably been foreseen at the time of writing the TSS. Such changes would be subject to consultation with our customers and stakeholders and would require AER approval.

7.2 Annual pricing proposal

We also submit an annual pricing proposal to the AER for assessment and approval. This proposal explains:

> how we propose to vary tariff levels from the start of the next financial year (1 July)

> any material differences between the prices proposed in the pricing proposal and the information on tariffs and tariff structures in our TSS

> reasons for any material differences between our annual pricing proposal and the indicative price schedule in our TSS.

7.3 Future TSS

Our next TSS will form part of our 2019-24 regulatory proposal and will cover the five year period from 1 July 2019 through to 30 June 2024. We hope to improve on our current TSS in a number of ways:

1. Better describe to our customers how our tariff reform program ties in with our planned network investment and demand management programs, including how our current demand management programs, for example Controlled Load, encourage more efficient use of the network.
2. Consider other non-price initiatives to address local network demand pressures, for example by encouraging more localised demand management.
3. Revisit our LRMC and LRMC calculation timeframe, including comparing our LRMC estimates with other distributors to understand the drivers for any differences and to ensure reasonableness.
4. Consider implementing a specific battery tariff.

As mentioned in section 2.4, we don't intend to update our tariff structures often, and will only do so after consultation with our stakeholders.

Our structures may change in future TSS periods to:

> account for capability changes in the metering population

> reflect customer preferences

> improve price signals to customers, or

> encompass changes within the electricity market that impact on our costs.

Consistent with the tariff setting approach outlined in section 4, in structuring our tariffs, Essential Energy will always aim to:

> ensure our tariffs are simple and transparent

> fairly allocate costs between customers based on their share of relevant network costs

> maintain predictable and relatively stable prices over time

> empower customers to make efficient electricity consumption choices

> provide pricing messages to customers that allow them to make appropriate usage decisions that will, in turn, drive the associated level of network expenditure required.

COMPLIANCE CHECKLIST

The table below contains the National Electricity Rules relevant to the TSS and where in the TSS Essential Energy has addressed each requirement.

Rule	Requirement	Addressed in
6.8.2 (a)	A Distribution Network Service Provider must, whenever required to do so under paragraph (b), submit to the AER a regulatory proposal and a proposed tariff structure statement related to the distribution services provided by means of, or in connection with, the Distribution Network Service Provider's distribution system.	TSS document, addendum and attachments
6.8.2 (b) (1) to (2)	A regulatory proposal and a proposed tariff structure statement must be submitted (1) At least 17 months before the expiry of a distribution determination that applies to the *Distribution Network Service Provider*; or (2) If no distribution determination applies to the *Distribution Network Service Provider*, within three months after being required to do so by the *AER*.	Transitional requirement for submission to be made on 27 November 2015
6.8.2 (c) (7)	A regulatory proposal must include (but need not be limited to) the following elements: > A description (with supporting materials) of how the proposed tariff structure statement complies with the pricing principles for direct control services including: > A description of where there has been any departure from the pricing principles set out in paragraphs 6.18.5 (e) to (g); and > An explanation of how that departure complies with clause 6.18.5(c).	Section 4.4 -*Setting our proposed tariffs*
6.8.2 (c1a)	The overview paper must also include a description of how the Distribution Network Service Provider has engaged with retail customers and retailers in developing the proposed tariff structure statement and has sought to address any relevant concerns identified as a result of that engagement.	Attachments 1 - *Overview of our TSS*
6.8.2 (d1)	The proposed tariff structure statement must be accompanied by an indicative pricing schedule.	Attachment 2 - *Indicative NUOS Pricing Schedule* Attachment 5 - *Alternative Control Pricing Schedule*
6.8.2 (d2)	The proposed tariff structure statement must comply with the pricing principles for direct control services.	This entire TSS document and Attachments
6.8.2 (e) and (f)	If more than one distribution system is owned, controlled or operated by a Distribution Network Service Provider, then, unless the AER otherwise determines, a separate regulatory proposal and a separate tariff structure statement are to be submitted for each distribution system. If, at the commencement of this Section, different parts of the same distribution system were separately regulated, then, unless the AER otherwise determines, a separate regulatory proposal and a separate tariff structure statement are to be submitted for each part as if it were a separate distribution system.	Not applicable
6.18.1A (a) 6.18.1A (a)(1)	A tariff structure statement of a Distribution Network Service Provider must include the following elements: (1) The tariff classes into which retail customers for direct control services will be divided during the relevant regulatory control period;	Section 3 - *Our proposed tariff classes* of the TSS document
6.18.1A (a)(2)	(2) The policies and procedures the Distribution Network Service Provider will apply for assigning retail customers to tariffs or reassigning retail customers from one tariff to another (including any applicable restrictions);	Section 4 - *Our proposed tariff structures* of the TSS document & Attachment 4 - *Policies and procedures for assignment and reassignment of tariffs*
6.18.1A (a)(3)	(3) The structures for each proposed tariff;	Section 4 - *Our proposed tariff structures* of the TSS document

Rule	Requirement	Addressed in
6.18.1A (a)(4)	(4) The charging parameters for each proposed tariff; and	
6.18.1A (a)(5)	A description of the approach that the Distribution Network Service Provider will take in setting each tariff in each pricing proposal of the Distribution Network Service Provider during the relevant regulatory control period in accordance with clause 6.18.5.	Section 5.2 - *Approach to setting tariffs* of the TSS document & section 4 - *Determining our proposed tariffs* of this document
6.18.1A (b)	A tariff structure statement must comply with the pricing principles for direct control services.	Section 5 - *Our Tariff Setting Methodology* of the TSS document & Section 4 - *Determining our proposed tariffs* of this document
6.18.1A (e)	A tariff structure statement must be accompanied by an indicative pricing schedule which sets out, for each tariff for each regulatory year of the regulatory control period, the indicative price levels determined in accordance with the tariff structure statement.	Attachment 2 - *Indicative NUOS Pricing Schedule* & Attachment *5 - Alternative Control Pricing Schedule*
6.18.3 (b)	Each customer for direct control services must be a member of one or more tariff classes.	Section 3 - *Our proposed tariff classes* of the TSS document
6.18.3 (c)	Separate tariff classes must be constituted for retail customers to whom standard control services are supplied and retail customers to whom alternative control services are supplied (but a customer for both standard control services and alternative control services may be a member of 2 or more tariff classes).	Section 3 - *Our proposed tariff classes* & Section 4 - *Our proposed tariff structures* of the TSS document. Also section 4.6 - *Alternative Control Services* of this document
6.18.3 (d) (1) to (2)	A tariff class must be constituted with regard to: (1) The need to group retail customers together on an economically efficient basis; and (2) The need to avoid unnecessary transaction costs.	Section 3 - *Our proposed tariff classes* of the TSS document
6.18.4 (a)	In formulating provisions of a distribution determination governing the assignment of retail customers to tariff classes or the re-assignment of retail customers from one tariff class to another, the AER must have regard to the following principles: (1) Retail customers should be assigned to tariff classes on the basis of one or more of the following factors: (i) The nature and extent of their usage; (ii) The nature of their connection to the network; (iii) Whether remotely-read interval metering or other similar metering technology has been installed at the retail customer's premises as a result of a regulatory obligation or requirement; (2) Retail customers with a similar connection and usage profile should be treated on an equal basis; (3) However, retail customers with micro-generation facilities should be treated no less favourably than retail customers without such facilities but with a similar load profile; (4) A Distribution Network Service Provider's decision to assign a customer to a particular tariff class or to re-assign a customer from one tariff class to another should be subject to an effective system of assessment and review.	Section 3 - *Our proposed tariff classes* of the TSS document & Attachment 4 - *Policies and procedures for assignment and reassignment of tariffs*
6.18.4 (b)	If the charging parameters for a particular tariff result in a basis of charge that varies according to the usage or load profile of the customer, a distribution determination must contain provisions for an effective system of assessment and review of the basis on which a customer is charged.	Section 4 - *Determining our proposed tariffs* & section 7 - *Future tariff structures and pricing directions*

Rule	Requirement	Addressed in
6.18.5 (a)	The network pricing objective is that the tariffs that a Distribution Network Service Provider charges in respect of its provision of direct control services to a retail customer should reflect the Distribution Network Service Provider's efficient costs of providing those services to the retail customer.	Section 4 - *Determining our proposed tariffs* of this document Section 5 - *Our Tariff Setting Methodology* of the TSS document Also Attachment 4 - *Estimation of Long Run Marginal Cost and Other Concepts Related to the Distribution Pricing Principles from Houston-Kemp* & 5 - *Economic model from Houston-Kemp* from our original TSS
6.18.5 (b)	Subject to paragraph (c), a Distribution Network Service Provider's tariffs must comply with the pricing principles set out in paragraphs (e) to (j).	
6.18.5 (c) (1) to (2)	A Distribution Network Service Provider's tariffs may vary from tariffs which would result from complying with the pricing principles set out in paragraphs (e) to (g) only: (1) To the extent permitted under paragraph (h); and (2) To the extent necessary to give effect to the pricing principles set out in paragraphs (i) to (j).	
6.18.5 (d)	A Distribution Network Service Provider must comply with paragraph (b) in a manner that will contribute to the achievement of the network pricing objective.	
6.18.5 (e) (1) to (2)	For each tariff class, the revenue expected to be recovered must lie on or between: (1) An upper bound representing the stand-alone cost of serving the retail customers who belong to that class; and (2) A lower bound representing the avoidable cost of not serving those retail customers.	
6.18.5 (f) (1) to (3)	Each tariff must be based on the long run marginal cost of providing the service to which it relates to the retail customers assigned to that tariff with the method of calculating such cost and the manner in which that method is applied to be determined having regard to: (1) The costs and benefits associated with calculating, implementing and applying that method as proposed; (2) The additional costs likely to be associated with meeting demand from retail customers that are assigned to that tariff at times of greatest utilisation of the relevant part of the distribution network; and (3) The location of retail customers that are assigned to that tariff and the extent to which costs vary between different locations in the distribution network	
6.18.5 (g) (1) to (3)	The revenue expected to be recovered from each tariff must: (1) Reflect the Distribution Network Service Provider's total efficient costs of serving the retail customers that are assigned to that tariff; (2) When summed with the revenue expected to be received from all other tariffs, permit the Distribution Network Service Provider to recover the expected revenue for the relevant services in accordance with the applicable distribution determination for the Distribution Network Service Provider; and (3) Comply with sub-paragraphs (1) and (2) in a way that minimises distortions to the price signals for efficient usage that would result from tariffs that comply with the pricing principle set out in paragraph (f).	

Rule	Requirement	Addressed in
6.18.5 (h) (1) to (3)	A Distribution Network Service Provider must consider the impact on retail customers of changes in tariffs from the previous regulatory year and may vary tariffs from those that comply with paragraphs (e) to (g) to the extent the Distribution Network Service Provider considers reasonably necessary having regard to: (1) The desirability for tariffs to comply with the pricing principles referred to in paragraphs (f) and (g), albeit after a reasonable period of transition (which may extend over more than one regulatory control period); (2) The extent to which retail customers can choose the tariff to which they are assigned; and (3) The extent to which retail customers are able to mitigate the impact of changes in tariffs through their usage decisions.	Section 5 - *Our Tariff Setting Methodology* of the TSS document Section 4.4 -*Setting our proposed tariffs* of this document
6.18.5 (i) (1) to (2)	The structure of each tariff must be reasonably capable of being understood by retail customers that are assigned to that tariff, having regard to: (1) The type and nature of those retail customers; and (2) The information provided to, and the consultation undertaken with, those retail customers.	Section 4.4 -*Setting our proposed tariffs* of this document Section 5.1.5 - *Our tariffs can be easily understood by customers* of the TSS document
6.18.5 (j)	A tariff must comply with the Rules and all applicable regulatory instruments.	Section 5 – *Our tariff setting methodology* of the TSS document Section 4.4.2 - *Our compliance with the pricing objective and* principles of this document
6.18.6 (a)	This clause applies only to tariff classes related to the provision of standard control services.	
6.18.6 (b)	The expected weighted average revenue to be raised from a tariff class for a particular regulatory year of a regulatory control period must not exceed the corresponding expected weighted average revenue for the preceding regulatory year in that regulatory control period by more than the permissible percentage.	Attachment 2 - *Indicative NUOS Pricing Schedule*
6.18.6 (c) (1) to (2)	The permissible percentage is the greater of the following: (1) The CPI-X limitation on any increase in the Distribution Network Service Provider's expected weighted average revenue between the two regulatory years plus 2%; Note: The calculation is of the form (1 + CPI)(1 – X)(1 + 2%) (2) CPI plus 2%. Note: The calculation is of the form (1 + CPI)(1 + 2%)	
6.18.6 (d) (1) to (4)	In deciding whether the permissible percentage has been exceeded in a particular regulatory year, the following are to be disregarded: (1) The recovery of revenue to accommodate a variation to the distribution determination under rule 6.6 or 6.13; (2) The recovery of revenue to accommodate pass through of designated pricing proposal charges to retail customers; (3) The recovery of revenue to accommodate pass through of jurisdictional scheme amounts for approved jurisdictional schemes; and (4) The recovery of revenue to accommodate any increase in the Distribution Network Service Provider's annual revenue requirement by virtue of an application of a formula referred to in clause 6.5.2(l).	Attachment 2 - *Indicative NUOS Pricing Schedule*
6.18.7 (a)	A pricing proposal must provide for tariffs designed to pass on to retail customers the designated pricing proposal charges to be incurred by the Distribution Network Service Provider.	Section 4.4 - *Setting our proposed tariffs* of this document

Rule	Requirement	Addressed in
6.18.7 (b)	The amount to be passed on to retail customers for a particular regulatory year must not exceed the estimated amount of the designated pricing proposal charges adjusted for over or under recovery in accordance with paragraph (c).	& Attachment 2 - *Indicative NUOS Pricing Schedule*
6.18.7 (c) (1) to (3)	The over and under recovery amount must be calculated in a way that: (1) Subject to subparagraphs (2) and (3) below, is consistent with the method determined by the AER in the relevant distribution determination for the Distribution Network Service Provider; (2) Ensures a Distribution Network Service Provider is able to recover from retail customers no more and no less than the designated pricing proposal charges it incurs; and (3) Adjusts for an appropriate cost of capital that is consistent with the allowed rate of return used in the relevant distribution determination for the relevant regulatory year.	Attachment 2 - *Indicative NUOS Pricing Schedule*
6.18.7 (d) (1) to (3)	Notwithstanding anything else in this clause 6.18.7, a Distribution Network Service Provider may not recover charges under this clause to the extent these are: (1) Recovered through the Distribution Network Service Provider's annual revenue requirement; (2) Recovered under clause 6.18.7A; or (3) Recovered from another Distribution Network Service Provider.	
6.18.7A (a)	A pricing proposal must provide for tariffs designed to pass on to customers a Distribution Network Service Provider's jurisdictional scheme amounts for approved jurisdictional schemes.	Section 4.3.4 - *Treatment of pass through costs* & Attachment 2 - *Indicative NUOS Pricing Schedule*
6.18.7A (b)	The amount to be passed on to customers for a particular regulatory year must not exceed the estimated amount of jurisdictional scheme amounts for a Distribution Network Service Provider's approved jurisdictional schemes adjusted for over or under recovery in accordance with paragraph (c).	
6.18.7A (c) (1) to (3)	The over and under recovery amount must be calculated in a way that: (1) Subject to subparagraphs (2) and (3) below, is consistent with the method determined by the AER for jurisdictional scheme amounts in the relevant distribution determination for the Distribution Network Service Provider, or where no such method has been determined, with the method determined by the AER in the relevant distribution determination in respect of designated pricing proposal charges; (2) Ensures a Distribution Network Service Provider is able to recover from customers no more and no less than the jurisdictional scheme amounts it incurs; and (3) Adjusts for an appropriate cost of capital that is consistent with the allowed rate of return used in the relevant distribution determination for the relevant regulatory year.	
6.18.7A (d) (1) to (2)	A scheme is a jurisdictional scheme if: (1) The scheme is specified in paragraph (e); or (2) The AER has determined under clause paragraph (l) that the scheme is a jurisdictional scheme, and The AER has not determined under paragraph (u) that the scheme has ceased to be a jurisdictional scheme.	
6.18.7A (e) (1) to (3)	For the purposes of paragraph (d)(1), the following schemes are jurisdictional schemes: (1) Schemes established under the following laws of participating jurisdictions: (i) Electricity Feed-in (Renewable Energy Premium) Act 2008 (ACT); (ii) Division 3AB of the Electricity Act 1996 (SA);	

Rule	Requirement	Addressed in
	(iii) Section 44A of the Electricity Act 1994 (Qld); (iv) Electricity Industry Amendment (Premium Solar Feed-in Tariff) Act 2009 (Vic); (2) The Solar Bonus Scheme established under the Electricity Supply Act 1995 (NSW); and (3) The Climate Change Fund established under the Energy and Utilities Administration Act 1987 (NSW).	
6.19.2 (a)	Subject to the Law and the Rules, all information about a Service Applicant or Distribution Network User used by Distribution Network Service Providers for the purposes of distribution service pricing is confidential information.	Requirement adhered to throughout entire TSS
6.19.2 (b)	No requirement in this Chapter 6 to publish information about a tariff class is to be construed as requiring publication of information about an individual retail customer.	
No applicable Rule	Essential should make claims for confidentiality in accordance with the AER's Confidentiality Guideline.	