Attachment 1
Tariff Structure Explanatory Statement

January 2019

Contents

1 Executive Summary

Customer and stakeholder engagement

We consulted widely prior to submitting our Proposed Tariff Structure Statement (TSS). The overriding message was for Essential Energy to move to more cost-reflective charges using a slow and careful transition and for customers to be given options.

Since the release of the Australian Energy Regulator's (AER's) Draft Determination on 1 November 2018. we have undertaken further consultation with customers, stakeholders, retailers and other New South Wales (NSW) distribution networks. We sought input into our Revised TSS and feedback on issues raised by the AER in not approving our Proposed TSS.

We received a wide range of responses and this feedback has informed our Revised TSS.

Highlights of our Revised TSS

Our Revised TSS contains the following changes:

> We have removed replacement capital expenditure (repex) not related to incremental demand from our long run marginal cost (LRMC) as recommended by the AER.

> We have shortened the time period of the demand charge for residential and small business customers as recommended by the AER. Instead of operating in both the peak and shoulder period (7am to 10pm), the demand charge will only operate in the peak period (5pm to 8pm weekdays).

> All residential and small business customers will be automatically assigned to a time-of-use (ToU) default network charge (tariff) when they install a smart meter, regardless of whether they are connecting new technologies like solar PV.

However, we have maintained the ability for Residential and Small Business customers to opt out to a flat network charge.

What happens next?

The AER will assess our Revised Proposal, including the Revised TSS, and make its final determination on 30 April 2019. The associated network charges and structures will come into operation on 1 July 2019.

Customers are invited to read our Revised TSS and provide feedback to the AER through their website at aer.gov.au or to us directly using one of the communication channels detailed below.

Website: www.essentialenergy.com.au/yoursay
Email: yoursay@essentialenergy.com.au
Post: Head of Stakeholder Engagement, Essential Energy,
PO Box 5730, Port Macquarie NSW 2444
Phone: 13 23 91

Social media: Facebook YouTube Twitter LinkedIn

2 Background

What is the Tariff Structure Explanatory Statement?

This Tariff Structure Explanatory Statement (TSES) supports Essential Energy's Revised TSS. Our Proposed TSS was lodged with the AER in April 2018 as part of our Regulatory Proposal (Proposal). The AER made a Draft Determination on our Proposed TSS on 1 November 2018. Whilst the AER agreed with some aspects of our Proposed TSS, it was not fully accepted.

This TSES explains how we have addressed the issues raised by the AER in its Draft Determination, as well as issues raised by stakeholders in relation to our Proposed TSS. It outlines how the feedback from recent consultations with customers and stakeholders has informed the pricing strategy for the 2019–24 regulatory period outlined in our Revised TSS.

Our Revised TSS and this TSES document will inform the AER's assessment of our compliance with relevant provisions of the National Electricity Rules (NER). Once our TSS is approved, we must ensure our annual pricing approval applications within the 2019-24 regulatory period accord with it.

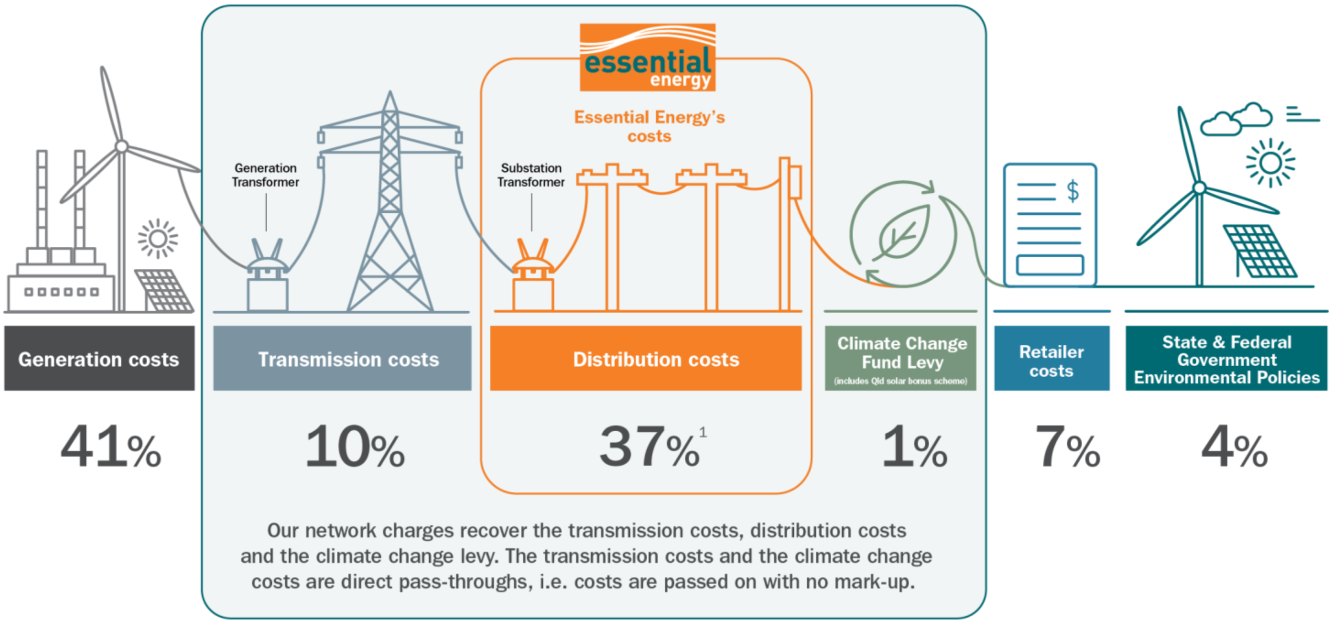
Essential Energy's role in the electricity process

Essential Energy is an electricity distributor, so our TSS and TSES only addresses distribution costs, which are just one part of the total retail bill that customers pay.

Our network charges represent our costs to operate and maintain the distribution network and are the subject of the Proposal of which this TSS is a part. On a customer's bill, our charges are bundled with:

> Transmission costs, which are also regulated by the AER. These costs from TransGrid and Powerlink, the operators of the transmission networks that our distribution network connects to, are passed on to customers.

> Government imposed levies to pay for the Climate Change Fund and contributions to the Queensland Solar Bonus Scheme.



Characteristics that inform our pricing

The electricity industry is in a period of unprecedented change, driven by changes in the way our customers source and use energy, the push to decarbonise our energy supply, and increased decentralisation of the energy supply chain.

As these changes occur, we expect to have both active customers who invest in new technologies and change their energy sourcing and usage behaviours, and passive customers who continue to use energy in much the same way as they do today.

We need to ensure our price structures fits both customer types, so we can best support all our customers' long-term interests. Doing this means designing network charges that recognise the characteristics of our network and our customers now and for the foreseeable future.

Our tariff strategy is based on the pricing principles we developed to provide a framework for Essential Energy's long-term transition to cost-reflective pricing. These principles are:

[1]Based on the 2017–18 forecast, Australian Energy Market Commission, 2017 Residential Electricity Price Trends, 18 December 2017 p. 100

2 Background

We will see network charges design as successful when:

- > customers want to use the network and are willing to pay for how they use it;
- > our charges support the long-term commercial sustainability of our business;
- > transition is sensitive to understanding impacts and implications for our customers;
- > we deliver customer and stakeholder education and engagement to both design and implement changes to our network charges; and
- > the long-term interest of customers is served by looking at options and providing solutions.

We will see our service provision as successful when:

- > we understand which customers, feeders and locations we can efficiently support and which may have alternative (cheaper or more reliable) solutions; and
- > we support alternative connections and usage of the network through clear network charges, policies and processes.

Our approach to encourage the adoption of more cost-reflective network charges

During the 2019-24 period we propose that the transition to cost-reflective pricing for our customers is based on a blend of network charges that encourage voluntary uptake of options. Outcomes and learnings from the 2019-24 period will inform the 2024-2029 TSS.

		Trials	We will conduct customer trials to test other pricing options such as capacity based network charges, peak rebate and other techniques that may encourage customer response. These trials will inform future TSS's.
Incentives	We have prepared this TSS so financial incentives built into our individual network charges will encourage Residential and Small Business customers to opt-in to more cost-reflective network prices.	**Technology**	As a key enabler, smart metering and home energy management systems will help facilitate the transition to cost-reflective pricing. We will adapt and design our network charges to ensure maximum benefits.
Education	We will increase education about our network charges to advocate the benefits of cost-reflective pricing.	**Network Economics**	We are working hard to understand the cost drivers at localised areas within our network, so we can better target and provide solutions that will deliver long term benefit for all customers.
Collaboration	We will work closely with retailers to encourage adoption of more cost-reflective network charges options.	**Systems**	We are upgrading our systems which will provide more options and scope to increase innovation in tariff design.

3 Feedback On Our Proposed TSS

Stakeholder issues considered in shaping our Revised TSS

The table below summarises the issues raised by the AER in not approving our proposed TSS and our response to each of those issues. It also addresses other questions and issues raised by stakeholders, retailers and customers in their submissions to our Proposal.

	Draft Determination item/ stakeholder issue	Our response	Reasoning	Chapter
1.	Tariffs should be technology neutral (small customers should be on same network charge regardless of what technology they connect)	We will assign all small customers to the same ToU network charge, regardless of any new technology.	> Demand charges are hard for small customers to understand > Analysis by the AER shows no clear advantage in demand pricing compared to ToU pricing on our network > Generally supported by customers and stakeholders	6 - Technology-neutral Network Charging Assignment
2.	Time period for demand charge for small customers is too wide	We will reduce the time period to cover the peak period (5-8pm weekdays) only.	> We agree that it provides a better signal to reduce demand during the peak period > Analysis shows significant impact to Small Business customers and a transition approach is required > Customers and stakeholders generally supported a narrower time period	7 - Peak Demand Charging Window
3.	Allow customers a 12-month sampling period before moving to cost reflective tariffs	We propose to continue to assign a cost reflective network charge to customers when they receive a smart meter upgrade	> Delays move to cost reflectivity > Delays potential savings > Procedurally difficult > Unclear where sampling analysis would come from > May lead to confusion with customers – no clear trigger for change > Mixed response from customers and stakeholders	8 - Timing of Network Charge Assignment
4.	Don't allow customers to opt out to flat rate tariff	We propose to continue to allow customers to opt-out of time-of-use network charges to flat rate	> Supported by customers and stakeholders as provides customer choice > Flat rate network charge is priced less favourably than more cost-reflective charges to discourage customers moving to it	9 - Ability to Opt Out
5.	Describe how tariffs are based on LRMC and how residuals are recovered	We provide further explanation in this document	> Clarity and transparency of the network charge setting process is important to customers and stakeholders	5 - Our Pricing Proposal Methodology
6.	LRMC shouldn't include repex not related to incremental demand	We have removed repex not related to increase in demand from our LRMC calculations	> We agree that this expenditure is not an indicator of forward-looking growth-related costs	5 - Our Pricing Proposal Methodology
7.	Explain why there are higher tariff levels for small business customers – they have a higher fixed charge, and why their charges have different rates	We provide further explanation in this document	> Rates have varied historically > We have provided a transitional path for these rates both historically and into the future	5 - Our Pricing Proposal Methodology
8.	Outline the approach to setting individually calculated tariffs (site-specific) and how they differ to sub-transmission tariffs	We have outlined the methodology in this document	> Reasonable to provide an explanation of this process	10 - Other Issues

	Draft Determination item/ stakeholder issue	Our response	Reasoning	Chapter
9.	Provide greater certainty and clarity on the approach as to how any over/under recovery under the revenue cap will be managed when setting prices in the annual pricing proposals	> We have outlined the approach within this document	> Certainty and clarity in the annual pricing setting approach is important to customers and stakeholders	10 - Other Issues
10.	Can there be consistency in network charges between NSW distributors?	> We have aligned where possible but are unable to provide consistent network charge structures across NSW distributors	> Our networks have varying levels of peak demand	10 - Other Issues
11.	What education is planned for transitional tariff customers, demand-based tariffs and Distributed Energy Resource (DER) owners?	> Our education initiatives are summarised in this document and will evolve over time	> Education is a critical element of the transition to cost reflective prices	10 - Other Issues
12.	Innovation – what are we trialling in terms of: > demand response and network price signals > "solar" network charge as a form of controlled load > battery exports as a demand management or network support?	> We have outlined some trial initiatives in this document > We remain committed to testing many options over the next regulatory period	> Pilots and trials are fundamental to the network of the future	11 - The Future
13.	What is the long-term network charge strategy?	> We will continue a slow and steady transition	> Our pricing principles shape our strategy. Our transition path will avoid price shocks for customers and ensure the long-term transition is sensitive to customers	2 - Background 10 - Other Issues 11 - The Future
14.	Expand the customer bill impact analysis where possible	> Provided additional customer bill impact where possible	> Customer impact analysis updated > We have included further analysis of the impacts of our revised TSS on our customers throughout this document	5 – Our Pricing Proposal Methodology
15.	The renaming of controlled load charges as 'Energy Saver' is misleading as customers' are saving money (not energy), but with higher carbon emissions	> Maintain 'Energy Saver' title	> This can save customers money and affordability is one of Essential Energy's customers' top values > When preparing our Proposal, Essential Energy tested various names for "controlled load" and Energy Saver was the preferred option	N/A
16.	What is the rationale for including a weekday morning peak period for households with type 5 (interval) meters, but not for households with type 4 (smart) meters?	> Explanation is included in this document	> It is important to explain why we have a morning peak period on some network charges	10 - Other Issues
17.	How does the $5 increase in fixed charges relate to the fixed charge shown in the Indicative Network Use of System (NUOS) Pricing Schedule?	> Explanation is included in this document	> Certainty and clarity in the annual pricing setting approach is important to customers and stakeholders	10 - Other Issues

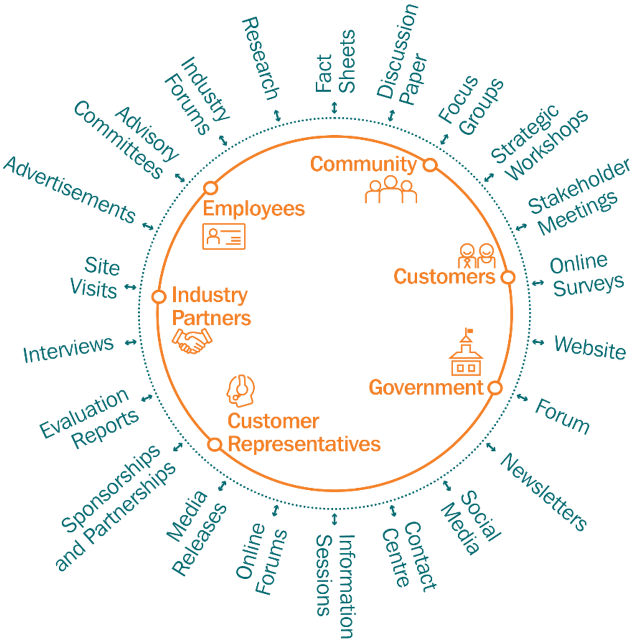
4 How We Engaged to Develop Our Revised TSS

'Outside in' customer engagement

Given the AER had largely accepted our 2019-24 Proposal, network charges formed the main area where we wanted to get further customer feedback before submitting our Revised Proposal and TSS.

We had already completed almost two years of customer engagement and received the Energy Consumers Australia and Energy Networks Australia 2018 Consumer Engagement Award for our efforts, so we decided to continue with the same approach. This had seen our business move away from the tradition of 'surveying' our customers, to making sure we are truly engaging, listening to and involving our customers in our decisions.

Customer and stakeholder workshops, forums, surveys, interviews, digital micro-sites and a range of other channels were used to work closely with customers and communities across regional, rural and remote NSW for an 'outside in' result that delivers the services customers value most.



To maintain independence, we re-engaged Woolcott Research and Engagement to facilitate these activities.

Putting engagement into practice

When developing our Proposal and Revised Proposal, our engagement programs fell into four broad phases that built from initial understanding of customer priorities to refining key elements in our Revised Proposal:

1. Understanding our customers

This phase helped us understand what parts of the energy equation were most important to our customers and stakeholders. We published a Discussion Paper to provide background information about our business, with an open invitation seeking customer opinions, and launched Essential Engagement (an online forum for people to have their say on key initiatives in the Proposal to promote digital dialogue).

We conducted interviews, surveys and seven deliberative forums with 513 customers, where sitting alongside Essential Energy executives and field workers -they identified the values that mattered most to them.

Safety, affordability and reliability were customers' top priorities, followed by customer service, renewable energy, bill transparency and innovation.

Our customers' top priorities

SAFETY LEADER

Safety is essential for doing business

Affordability

Reliability

Good customer service and communication

Encourage renewables

Bill itemisation

Innovative technologies

2. Stakeholder 'Deep Dive' workshops

This phase delved further into the top customer priorities to help identify areas where we could do better while setting the business up for a new world of decarbonised, decentralised, digitised energy solutions.

The engagement activities included (but were not limited to) online surveys, seven further deliberative forums with 518 attendees (54 per cent repeat participants), and workshops dedicated to understanding stakeholder views on how network charges should be set to improve network efficiency and help reduce distribution customer costs.

3. 'Testing and submission'

This phase checked what we had heard and allowed us to close the loop. This meant comparing what our customers had told us during earlier consultation with the corresponding items in our Proposal, including how we should structure our network charges. We could then be confident that customer and stakeholder views were reflected in our Proposal. The Proposal was also accompanied by customer and stakeholder fact sheets that provided a plain language summary of how we responded to the important matters they raised.

By this stage, Essential Energy had experienced over 3,000 individual interactions, with some customers investing over 10 hours in different forums to help us understand and capture their energy priorities and perspectives.

We were comfortable we had captured the customer and stakeholder perspectives in our Proposal, this was confirmed when the AER largely supported our Proposal in its Draft Determination released on 1 November 2018.

4. Refining

This phase of engagement followed the AER's Draft Determination. It enabled us to share and debate the AER's feedback with customers and stakeholders, and to seek further feedback on key areas to be addressed in our Revised Proposal.

We wanted to make sure customers understood the AER's Draft Determination and how it related back to the original customer and stakeholder discussions that started almost two years earlier. Further customer forums, stakeholder deep dives and one-on-one interviews enabled us to refine the Revised Proposal further in key areas such as network charge design and application, and the network of the future.

For example, we tested how the application of cost-reflective network charges might depend on when a smart meter was installed at a customer's premise, and the implications for customers connecting new technologies such as solar PV and batteries on the network.

Customers attending the network charges deliberative forum in Wagga Wagga, 13 November 2018

We thank all the customers and stakeholders involved in this process for their time, commitment, energy and enthusiasm. Their feedback and input to the Proposal and Revised Proposal have helped to inform the energy future for regional, rural and remote NSW.

An engagement program summary report was published after each consultation phase. The independent reports related to Phases 1, 2 and 3 were attachments to our Proposal. The report for Phase 4 is in Attachment 4.1 of our Revised Proposal.

There is also more information about our stakeholder engagement in Chapter 4 – Our Customer Engagement of the Revised Proposal.

Recent pricing related engagement activities

AUG 2018

14 AUG – **Customer Advocacy Group meeting**
Tariff Structure Statement, approach to encourage adoption of cost reflective network charges, ACCC network charges recommendations

6 SEP – **Meetings with other DNSPs**
Ausgrid and Endeavour

29 OCT – **CCP10**
Pre release briefing on AER Draft Determination on the Regulatory Proposal and Tariff Structure Statement

5 NOV – **Stakeholder deep dive workshop**
Public Interest Advocacy Centre (PIAC), NSW Farmers, Cotton Australia, Energy Consumers Australia (ECA), Electricity & Water Ombudsman NSW (EWON), Red Energy/Lumo, AI Group
Overview of Tariff Structure Statement and Draft Decision, assignment of network charges, cost reflective pricing, charging windows, ability to opt-out

8 NOV – WOOLCOTT **Customer Deliberative Forum Dubbo**
Overview of Tariff Structure Statement and Draft decision, assignment of network charges, cost reflective pricing, charging windows, ability to opt-out

9 NOV – **Meetings with other DNSPs**
Ausgrid and Endeavour

13 NOV – WOOLCOTT **Customer Deliberative Forum Wagga Wagga**
Overview of Tariff Structure Statement and Draft decision, assignment of network charges, cost reflective pricing, charging windows, ability to opt-out

15 NOV – **Customer Advocacy Group meeting**
Overview of Tariff Structure Statement and Draft decision, assignment of network charges, cost reflective pricing, charging windows, ability to opt-out

21 NOV – WOOLCOTT **Customer Deliberative Forum Port Macquarie**
Overview of Tariff Structure Statement and Draft decision, assignment of network charges, cost reflective pricing, charging windows, ability to opt-out

19-23 NOV – **Retailer consultation week (AGL, Energy Australia, Origin)**
Overview of Tariff Structure Statement and Draft decision, assignment of network charges, cost reflective pricing, charging windows, ability to opt-out

22 NOV – **1:1 Alternative Technology Association (ATA)**
Overview of Tariff Structure Statement and Draft decision, assignment of network charges, cost reflective pricing, charging windows, ability to opt-out

4 DEC – **1:1 Public Interest Advocacy Centre (PIAC)**
Overview of Tariff Structure Statement and Draft decision, assignment of network charges, cost reflective pricing,

7 DEC – **CCP10**
Review of feedback and proposed decisions

10 DEC – **Stakeholder deep dive workshop**
Public Interest Advocacy Centre (PIAC), NSW Farmers, NSW Irrigators Council, Cotton Australia
Review of feedback and proposed decisions

19 DEC – **Enova Energy**
Overview of Tariff Structure Statement and Draft decision, assignment of network charges, cost reflective pricing, charging windows, ability to opt-out

2019

Ongoing consultation with our customers and stakeholders

5 Our Pricing Proposal Methodology

The approach we have used in our TSS, and which we will use for our annual Pricing Proposals in 2019-24, accords with clause 16.8.5 of the NER.

Rule requirements

The pricing structures and indicative charges for this Revised TSS have all been developed following the pricing principles set out in the NER, particularly the principles relating to customer impact and ease of understanding.

The NER principles

Clause	Principle
6.18.5(e)	The revenue expected to be recovered for each tariff class must lie on or between > an upper bound representing the stand-alone cost of serving the retail customers who belong to that class; and > a lower bound representing the avoidable cost of not serving those retail customers
6.18.5(f)	Each tariff is based on the Long Run Marginal Cost (LRMC) of providing the service
6.18.5(g)	Tariffs reflect the efficient costs of serving customers and minimise distortions in price signals for efficient usage
6.18.5(h)	The need to consider the impact on customers of tariff changes
6.18.5(i)	Tariff structures must be reasonably capable of being understood by customers
6.18.5(j)	Tariffs must comply with all applicable regulatory instruments

What did we propose?

LRMC is a forward-looking measurement of adding an additional unit of demand. It provides a dollar value of the cost of augmenting the network to cater for this increased demand. This is an important indicator for users of the network when making choices about their electricity usage and when investing in energy related appliances and systems.

Our approach to estimating the LRMC across our network was detailed in Attachment 8 – How we design our tariffs of our Proposed TSS. We have not changed this method and therefore have not repeated it here.

When calculating the LRMC for our Proposed TSS, Essential Energy took into consideration the recommendations made by the AER in the current 2017-19 TSS, including:

> increasing the time horizon to a minimum of ten years;

> reviewing the methodology used to ensure it is appropriate; and

> Including repex related to growth.

We also provided an analysis of the Proposed TSS's impacts on customers.

AER Draft Decision on TSS

The AER has recommended the following improvements to our LRMC calculation and explanation:

> the LRMC calculation should not include the replacement of assets based on condition and age unless they are associated with an 'incremental demand' of network services

> clarify the description of how we will base our distribution network charges on the LRMC and our approach to recovering residual costs.

What do our customers and stakeholders think?

Most of our stakeholders agree that network charges should be cost-reflective. The AER's recommended changes to our LRMC calculations will help us to improve the cost-reflectivity of our distribution network charges.

Several stakeholders sought further analysis and information about the impacts on customers of our Proposed TSS where possible.

What have we proposed in our Revised TSS?

Given our consideration of the AER's Draft Determination and the stakeholder feedback we have:

> proposed an improved LRMC calculation that incorporates the AER's recommendations to remove some repex from the calculation

> further developed our explanation of how we will base our distribution network charges on the LRMC and our approach to recovering residual costs, including developing an infographic

> expanded our customer analysis to make the impact of the Revised TSS clearer.

Further explanation of each of these items follows.

Improving the calculation of our LRMC

For the Revised TSS, we have maintained the LRMC model and calculation methodologies from our Proposed TSS. However, we have adopted the AER's recommended changes to remove some repex from our calculations. This has improved the calculation of our LRMC as it includes only the subset of repex that is linked to the forecast incremental capacity that customers require of our network.

In our previous LRMC calculation we included all repex related to capacity additions. This approach did not adequately capture the fact that at the time of asset retirement, forecast required capacity may mean that we invest in a solution that increases, decreases or maintains capacity.

This improvement is reflected in the lower LRMC values in the table. For comparison, we have also provided the LRMC values included in our Proposed TSS.

LRMC unit costs

LRMC by Voltage Level	Proposed TSS Total LRMC at Voltage Level $/kVA	Revised TSS Total LRMC at Voltage Level $/kVA	Reduction in LRMC $/kVA
Subtransmission	14	14	0
High Voltage	117	95	22
Low voltage	138	113	25

Stand-alone and avoidable cost

The table shows our estimates of the stand-alone and avoidable cost for each customer class. We have not proposed any changes to our methodology.

Our calculations show that, for each customer class, the proposed revenue lies between the lower bound (avoidable cost) and upper bound (stand-alone cost). These estimates demonstrate that our proposed revenue lies between the stand-alone and avoidable costs in accordance with the requirements of clause 6.18.5(e).

How our proposed 2019-20 revenue ($m) by customer class complies with the NER

Customer class	Avoidable	Stand-alone	Proposed	Meets clause 6.18.5(e)
Low Voltage Residential & Small Business Customer	323	2,186	711	Yes
Low Voltage Demand	91	725	202	Yes
High Voltage Demand	29	250	49	Yes
Subtransmission	8	73	15	Yes
Unmetered	6	52	9	Yes

Explaining the link between LRMC, residual costs and our distribution network charges

Our proposed distribution network charges are designed to reflect our LRMC while also recovering our residual costs, as illustrated in the graphic.

PART 1. Determine LRMC by voltage level and network charge

Subtransmission | High voltage | Low voltage

Determine augmentation and replacement capital expenditure driven by increased demand plus related opex, by voltage level of the network

Calculate LRMC by voltage level of the network as $/kVA

Determine contribution to peak demand of each network charge at each voltage level

Subtransmission and High voltage: Apply diversity factor to calculate LRMC $/kVA

Low voltage: Apply diversity factor to calculate LRMC $/kVA OR Apply power factor to translate LRMC into $/kWh

1. Determine value of LRMC to be recovered from each network charge

Part 2. Determine residual costs by voltage level and network charge

2. Deduct total LRMC from annual allowed revenue to determine Residual costs

Subtransmission: Residual allocated to network charge components based on efficiency factor of the network charge

High voltage: Residual allocated to network charge components based on efficiency factor of the network charge

Low voltage: Residual allocated to network charge components based on efficiency factor of the network charge, using historical rates as starting point in the transition

1 + 2 Combine LRMC based components with residual costs to determine final network charge structures

PART 1 Determine LRMC by voltage level and distribution network charge

1. Determine expenditure driven by increased demand by voltage level of the network

Our modelling estimates the LRMC by system voltage level i.e. subtransmission, high voltage, and low voltage. The LRMC estimate includes a 10-year forecast to 2029 of three cost components:

> Growth related capital expenditure;

> Incremental operating and maintenance costs; and

> The component of repex that is related to forecast incremental demand.

After 2029, we have estimated values based on demand growth and expenditure per unit of demand inputs. Demand growth at each voltage level is forecast to 2029, then estimated based on population growth forecasts.

For the capital expenditure elements, we have estimated an annual cost/charge impact of expenditure. Annual costs are used to remove the requirement to model residual values of each capital expenditure item. The annual costs are then discounted to $2018-19.

Calculate LRMC by voltage level of the network

We use a 15-year Net Present Value (NPV), and the LRMC is calculated as the discounted costs divided by the forecast annual change in demand at each voltage level. This provides a $/kVA figure for the subtransmission, high voltage and low voltage sections of our network.

Because customers connected at low voltage levels are receiving their supply through the subtransmission, high voltage then low voltage sections of the network, their LRMC is higher than customers connected at subtransmission level. This is evident in the table below and results in a lower demand charge component for customers connected at higher voltages (generally very large businesses) than customers who are connected to the low voltage sections of our network.

How different expenditures contribute to our LRMC at each voltage level (real $2018-19)

Customer class	LRMC at voltage level	Growth capital expenditure	Repex	Growth operating expenditure	Voltage level component of LRMC	Total LRMC at voltage level
Subtransmission	($/kVA)	10	2	3	14	14
High voltage	($/kVA)	46	23	11	80	95
Low voltage	($/kVA)	8	7	2	18	113

2. Determine contribution to peak demand of each distribution network charge at each voltage level

The LRMC values by voltage levels are then broken down to a distribution network charge, and distribution network charge component level, by using each distribution network charge's contribution to peak demand on the network. This is done in several steps including applying a diversity factor per voltage level for demand components and a power factor for energy only components. The resulting figures are summarised in the table.

LRMC at distribution network charge level (real $2018-19)	Consumption only cents per kWh				Demand$/kVA per month		
	Non-ToU	Peak	Shoulder	Off-peak	Peak	Shoulder	Off-peak
Residential Anytime	1.51						
Residential-Opt-in Demand					5.63		
Residential ToU		4.97	2.28	0.18			
Residential ToU, Interval Meter		5.18	2.87	0.18			
Energy Saver 1	0.03						
Energy Saver 2	0.15						
Small Business Anytime	1.51						
Small Business ToU		4.34	2.57	0.19			
Small Business ToU >100MWh		7.29	2.11	0.20			
Small Business ToU, Interval Meter		7.23	2.14	0.19			
Small Business-Opt-in Demand					5.63		
Large Business Demand 3 Rate					2.75	2.52	0.37
LV ToU Demand-Alternate Tariff					2.81		
High Voltage Demand 3 rate					2.88	2.58	0.45
Subtransmission Demand 3 rate					0.70	0.34	0.02

3. Determine the value of LRMC to be recovered from each distribution network charge

LRMC is an indicator of future costs related to changes in demand. Given that LRMC is used to provide a price signal of future costs that are all variable over time, the variable component of our distribution network charges is set to reflect our LRMC. If the distribution network charge has a demand component, then this demand component is set to reflect LRMC. If there is no demand component, the energy ToU component is set to reflect our LRMC. For the less efficient flat rate distribution network charge, it is the energy component that reflects our LRMC.

Distribution network charge parameters that are set closer to the LRMC will have a smaller distortion on efficient usage decisions than those set further from the LRMC. If the variable component is higher or lower than the LRMC we will transition those components to the LRMC level over time, using a steady transition path.

PART 2 Determine residual costs by voltage level and distribution network charge

1. Deduct total LRMC from annual allowed revenue to determine the residual costs

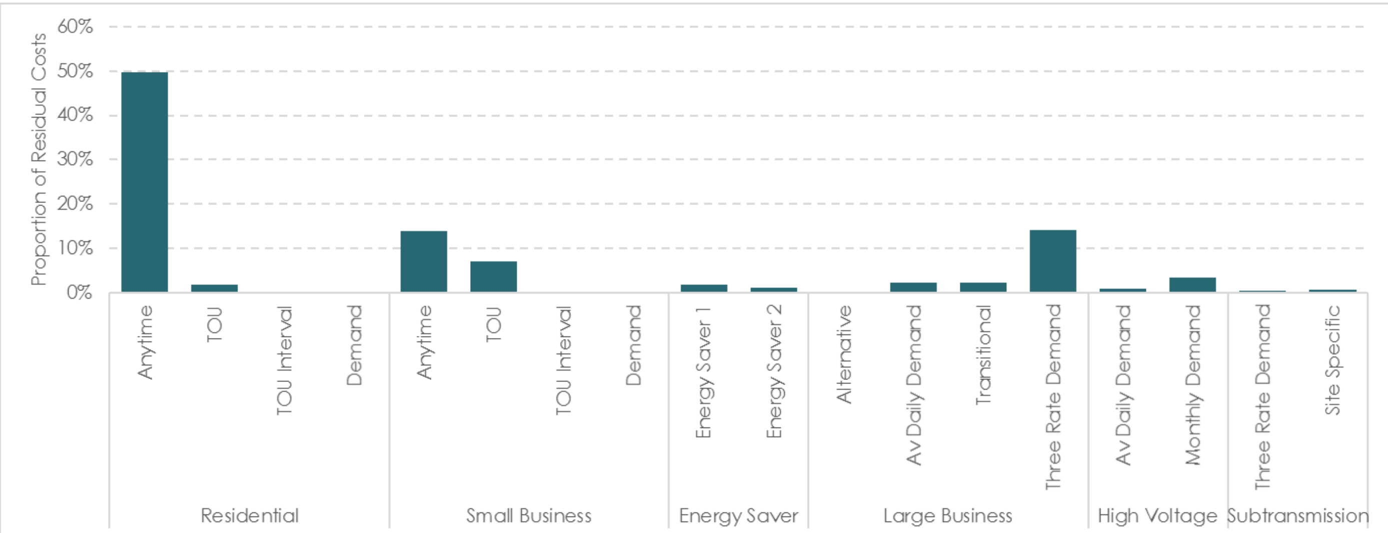
While LRMC is an indicator of forward-looking costs, the investment we have made in the past to build and maintain our network is known as residual cost. Most of the revenue we collect through our distribution network charges is related to recovering residual costs. These residual costs are the difference between the revenue we are allowed to earn each year to recover our efficient costs and our LRMC estimate.

As most of our costs are fixed (i.e. they do not vary with changes in energy consumed by customers) ideally, we would allocate the majority of residual costs to the fixed daily charge component of our prices. The remainder would then be allocated to the energy consumption component of our prices.

2. Allocate residual costs to distribution network charges

To ensure we are achieving the network pricing objectives, we allocate more residual costs to our least efficient distribution network charges – i.e. network charges that do not provide customers with efficient pricing signals for their energy consumption have higher distribution network charges than those on more efficient distribution network charges such as demand charges or ToU energy charges.

Allocation of residual costs between distribution network charges and customer types



PART 1 + PART 2 Combine LRMC with residual costs to determine distribution network charge structures

1. Consider the impacts on customers

As required under the NER s6.18.5(h), we take into consideration customer impacts when allocating residual costs to the various charging parameters of our distribution network charges. We achieve this by using our historical rates as a starting point then moving these rates to more efficient price signals each year using a steady transitional path.

We have set our pricing with these principles and objectives in mind to encourage customers to choose the distribution network charges that provide the best price signal. They either avoid adding to our peak demand and future network augmentation costs or pay a reasonable price that reflects their usage.

As most of our costs are residual and fixed, we would ideally allocate residual costs to the network access charge (fixed daily cost) component of our prices. However, this would have a considerable price impact on customers, so we are only increasing the fixed component of our distribution network charges for Residential and Small Business customers at a slow and steady rate, with the remainder allocated to the energy consumption components of our charges. This is detailed further in Chapter 10 Other Issues.

2. Develop final distribution network charge structures

We have continued this principles-based approach in determining the allocation of residual costs between the various charging parameters within each distribution network charge.

We have allocated a higher share of residual costs to charging parameters that are not closely linked to our LRMC cost drivers, (e.g., fixed daily cost and usage charges), with the demand charging parameters receiving the least residual costs. Again, this approach is more cost-reflective and more likely to change customers' consumption behaviour.

To put the split of residual costs for ToU and demand pricing in perspective, it is important to consider the allocation of residual costs in conjunction with the actual residual dollars allocated to each pricing component.

In line with this transition to more cost-reflective distribution network charges, we are increasing the fixed charge for Residential and Small Business customers by $5 a year over the 2019–24 period, in addition to any changes in the average distribution network charges. This will better align our fixed costs with our revenue from fixed charges. Fixed charges for large customers will change by the average increase (or decrease) each year.

This approach will help Essential Energy to make greater progress towards cost reflectivity while managing bill impacts on customers.

Customer bill impacts

In response to stakeholder feedback we have expanded our customer analysis to make the impact of our Revised TSS on different customers clearer.

Our proposed network charging approach is different for the 2019- 24 regulatory period than in our current TSS and will lead to changes in customers' network charges.

Average price changes may vary for each customer, depending on their consumption level.

The following analysis demonstrates:

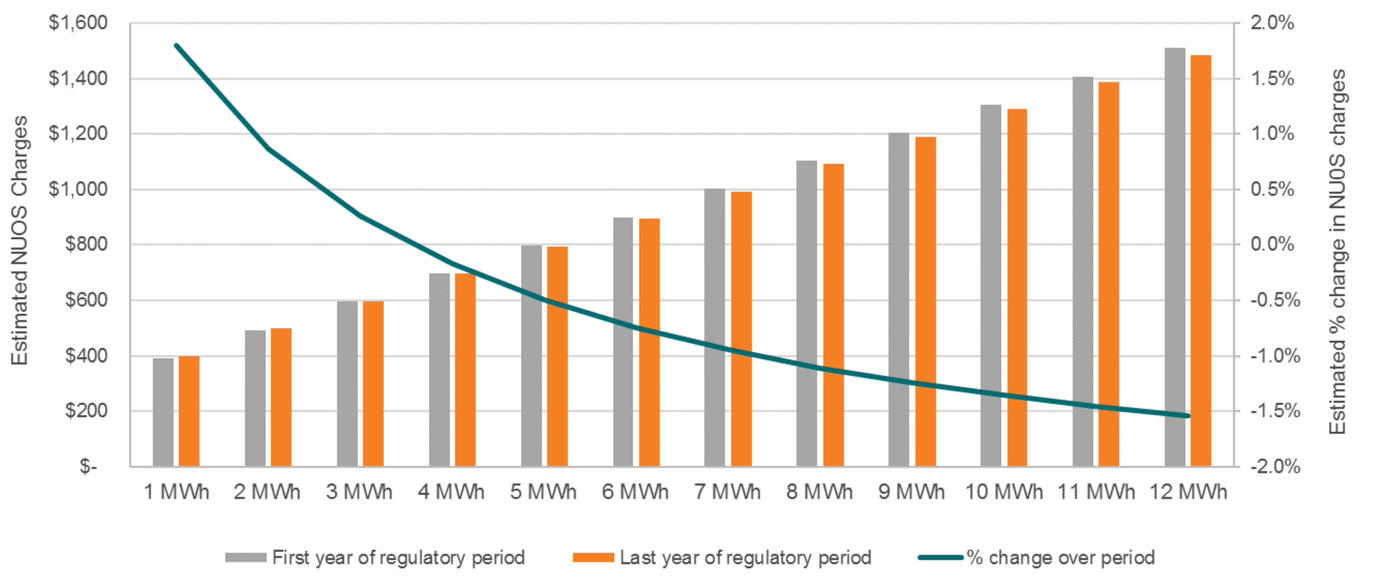
> the changes in our Anytime, ToU and demand-based network charges between 2019-20 and 2023-24 for our Residential and Small Business customers;

> the benefits for Residential and Small Business customers if they opt in to more cost-reflective network charges;

> the expected changes during 2019-20 to 2023-24 for our largest customers; and

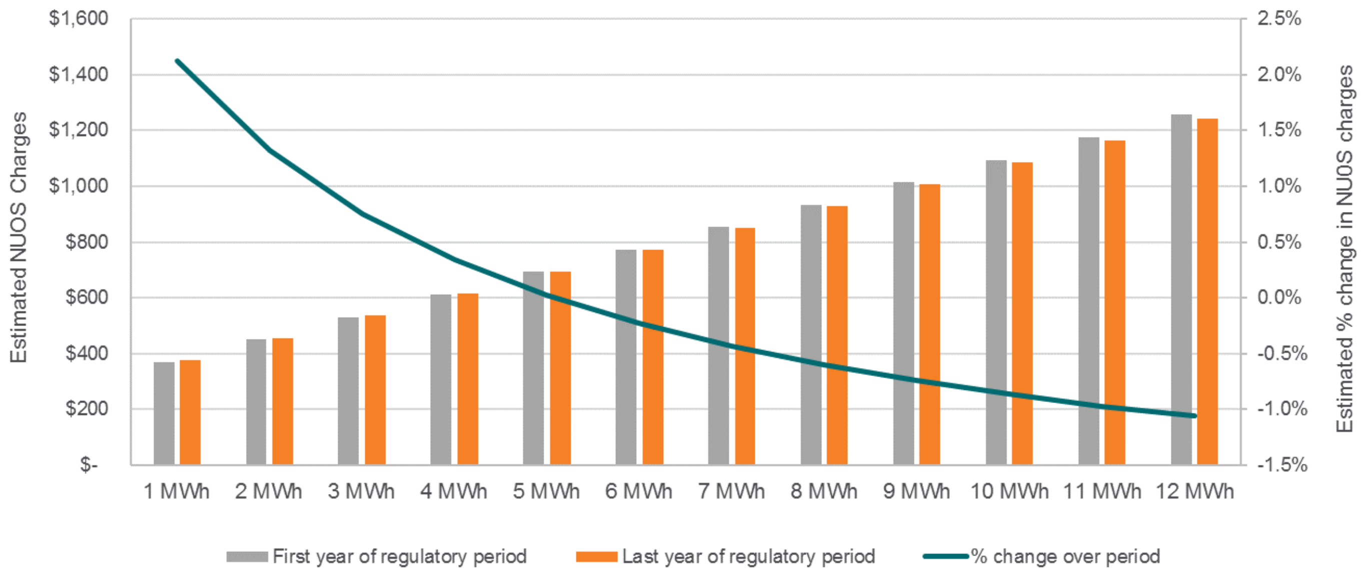
> the expected changes during 2019-20 to 2023-24 for our Residential customers, with and without solar generation.

Residential 'Anytime' flat rate network charge- estimated annual NUOS charge based on customer usage (real 2018-19)



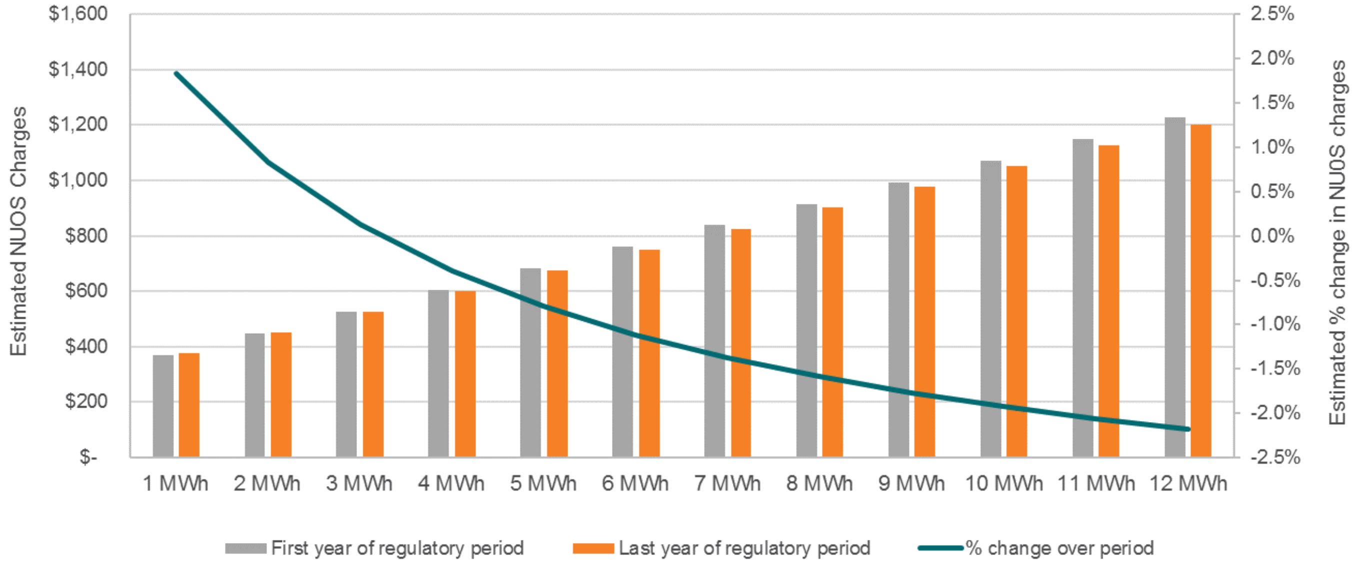
Annual customer usage	2019–20	2020–21	2021–22	2022–23	2023–24	Total $ change over the period	% Change over the period
1MWh	$392	$394	$398	$398	$399	$7	1.8%
2MWh	$494	$496	$499	$497	$498	$4	0.9%
3MWh	$595	$598	$601	$597	$597	$2	0.3%
4MWh	$697	$700	$703	$697	$696	-$1	-0.2%
5MWh	$798	$801	$804	$796	$794	-$4	-0.5%
6MWh	$900	$903	$906	$896	$893	-$7	-0.7%
7MWh	$1,002	$1,004	$1,007	$995	$992	-$9	-0.9%
8MWh	$1,103	$1,106	$1,109	$1,095	$1,091	-$12	-1.1%
9MWh	$1,205	$1,208	$1,211	$1,195	$1,190	-$15	-1.2%
10MWh	$1,306	$1,309	$1,312	$1,294	$1,289	-$18	-1.4%
11MWh	$1,408	$1,411	$1,414	$1,394	$1,387	-$20	-1.5%
12MWh	$1,510	$1,512	$1,515	$1,493	$1,486	-$23	-1.5%

Residential ToU network charge- estimated annual NUOS charge based on customer usage (real 2018-19)



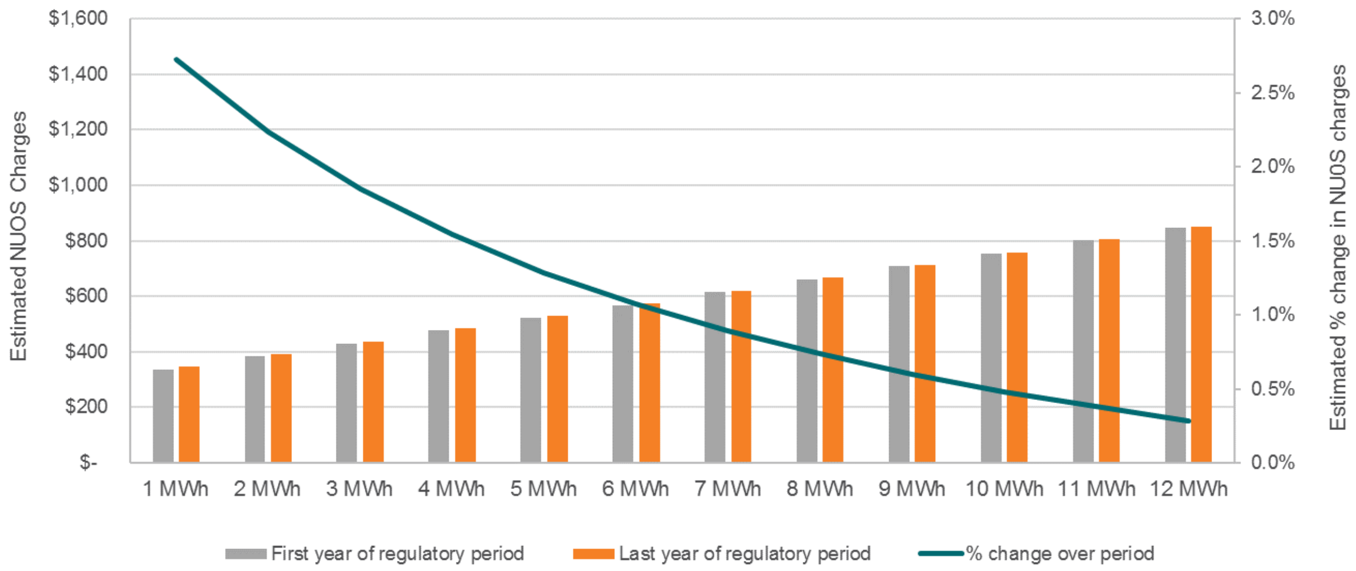
Annual customer usage	2019–20	2020–21	2021–22	2022–23	2023–24	Total $ change over the period	% Change over the period
1MWh	$371	$374	$376	$377	$379	$8	2.1%
2MWh	$451	$454	$456	$456	$457	$6	1.3%
3MWh	$532	$534	$536	$536	$536	$4	0.8%
4MWh	$612	$614	$616	$615	$614	$2	0.3%
5MWh	$693	$694	$696	$694	$693	$0	0.0%
6MWh	$773	$775	$776	$773	$772	-$2	-0.2%
7MWh	$854	$855	$856	$852	$850	-$4	-0.4%
8MWh	$934	$935	$936	$932	$929	-$6	-0.6%
9MWh	$1,015	$1,015	$1,015	$1,011	$1,007	-$8	-0.7%
10MWh	$1,095	$1,096	$1,095	$1,090	$1,086	-$9	-0.9%
11MWh	$1,176	$1,176	$1,175	$1,169	$1,164	-$11	-1.0%
12MWh	$1,256	$1,256	$1,255	$1,248	$1,243	-$13	-1.1%

Residential ToU interval network charge- estimated annual NUOS charge based on customer usage (real 2018-19)



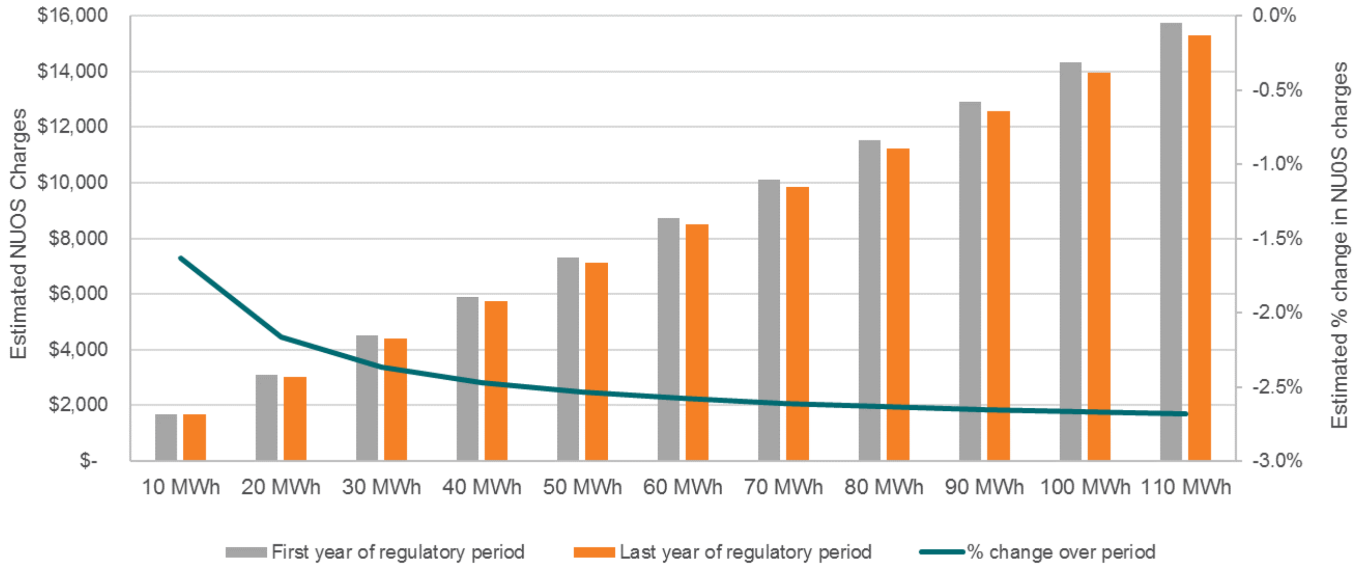
Annual customer usage	2019–20	2020–21	2021–22	2022–23	2023–24	Total $ change over the period	% Change over the period
1MWh	$369	$371	$373	$374	$375	$7	1.8%
2MWh	$447	$449	$450	$450	$451	$4	0.8%
3MWh	$525	$526	$527	$526	$526	$1	0.1%
4MWh	$603	$604	$604	$602	$601	-$2	-0.4%
5MWh	$682	$682	$681	$678	$676	-$5	-0.8%
6MWh	$760	$759	$758	$754	$751	-$8	-1.1%
7MWh	$838	$837	$835	$831	$827	-$11	-1.4%
8MWh	$916	$915	$912	$907	$902	-$15	-1.6%
9MWh	$994	$992	$989	$983	$977	-$18	-1.8%
10MWh	$1,073	$1,070	$1,066	$1,059	$1,052	-$21	-1.9%
11MWh	$1,151	$1,148	$1,143	$1,135	$1,127	-$24	-2.1%
12MWh	$1,229	$1,225	$1,220	$1,211	$1,202	-$27	-2.2%

Residential demand network charge- estimated annual NUOS charge based on customer usage (real 2018-19)



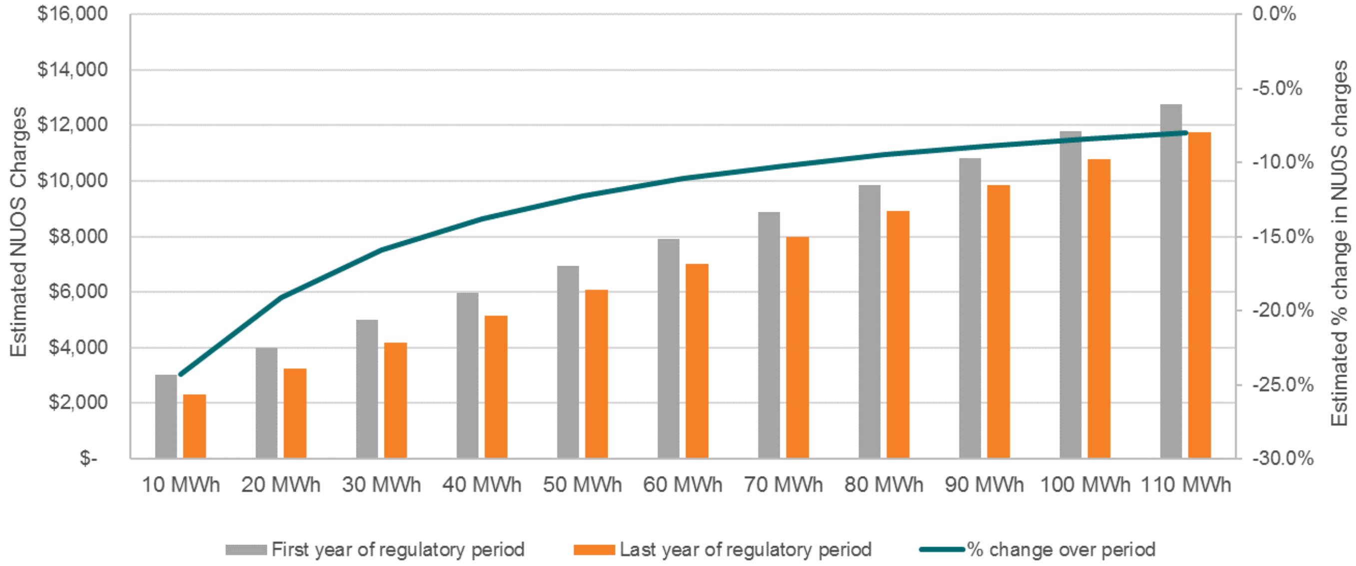
Annual customer usage	2019–20	2020–21	2021–22	2022–23	2023–24	Total $ change over the period	% Change over the period
1MWh	$337	$340	$343	$344	$346	$9	2.7%
2MWh	$383	$386	$389	$390	$392	$9	2.2%
3MWh	$430	$433	$435	$436	$438	$8	1.9%
4MWh	$476	$479	$482	$483	$484	$7	1.5%
5MWh	$523	$526	$528	$529	$529	$7	1.3%
6MWh	$569	$572	$575	$575	$575	$6	1.1%
7MWh	$616	$619	$621	$621	$621	$5	0.9%
8MWh	$662	$665	$668	$667	$667	$5	0.7%
9MWh	$709	$712	$714	$713	$713	$4	0.6%
10MWh	$755	$758	$760	$759	$759	$4	0.5%
11MWh	$802	$805	$807	$805	$805	$3	0.4%
12MWh	$848	$851	$853	$852	$850	$2	0.3%

Small Business 'Anytime' flat rate network charge- estimated annual NUOS charge based on customer usage (real 2018-19)



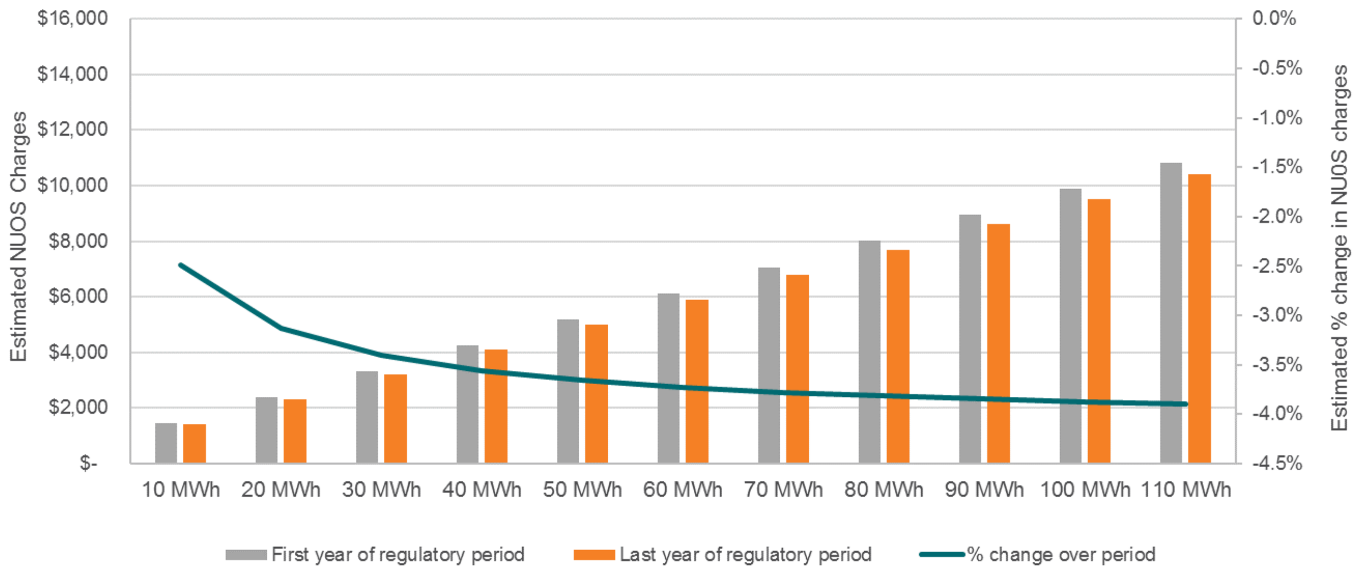
Annual customer usage	2019–20	2020–21	2021–22	2022–23	2023–24	Total $ change over the period	% Change over the period
10 MWh	$1,695	$1,692	$1,687	$1,677	$1,667	-$28	-1.6%
20 MWh	$3,100	$3,088	$3,076	$3,053	$3,032	-$67	-2.2%
30 MWh	$4,504	$4,484	$4,465	$4,429	$4,398	-$106	-2.4%
40 MWh	$5,909	$5,880	$5,854	$5,806	$5,763	-$146	-2.5%
50 MWh	$7,313	$7,276	$7,243	$7,182	$7,128	-$185	-2.5%
60 MWh	$8,718	$8,672	$8,632	$8,559	$8,493	-$225	-2.6%
70 MWh	$10,122	$10,069	$10,021	$9,935	$9,858	-$264	-2.6%
80 MWh	$11,527	$11,465	$11,410	$11,312	$11,223	-$304	-2.6%
90 MWh	$12,932	$12,861	$12,799	$12,688	$12,589	-$343	-2.7%
100 MWh	$14,336	$14,257	$14,187	$14,065	$13,954	-$382	-2.7%
110 MWh	$15,741	$15,653	$15,576	$15,441	$15,319	-$422	-2.7%

Small Business ToU network charge- estimated annual NUOS charge based on customer usage (real 2018-19)



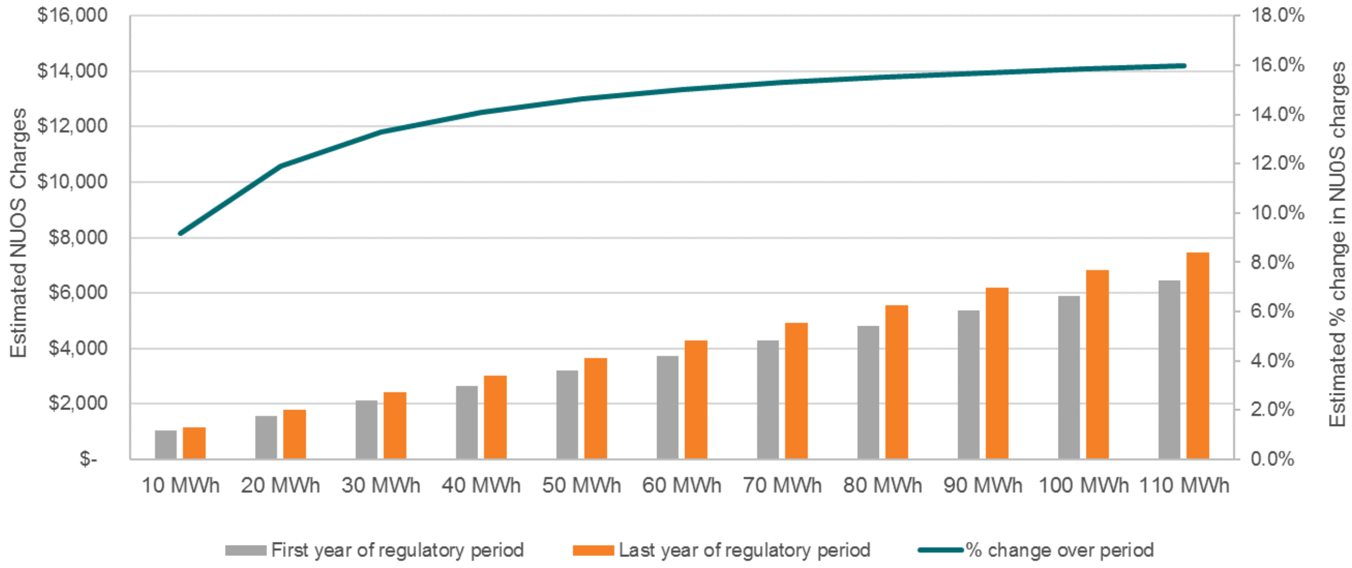
Annual customer usage	2019–20	2020–21	2021–22	2022–23	2023–24	Total $ change over the period	% Change over the period
10 MWh	$3,040	$2,829	$2,638	$2,461	$2,301	-$739	-24.3%
20 MWh	$4,012	$3,797	$3,601	$3,414	$3,246	-$766	-19.1%
30 MWh	$4,985	$4,765	$4,564	$4,368	$4,191	-$794	-15.9%
40 MWh	$5,957	$5,734	$5,528	$5,321	$5,136	-$822	-13.8%
50 MWh	$6,930	$6,702	$6,491	$6,275	$6,080	-$849	-12.3%
60 MWh	$7,902	$7,670	$7,454	$7,229	$7,025	-$877	-11.1%
70 MWh	$8,875	$8,638	$8,418	$8,182	$7,970	-$905	-10.2%
80 MWh	$9,848	$9,607	$9,381	$9,136	$8,915	-$933	-9.5%
90 MWh	$10,820	$10,575	$10,344	$10,090	$9,860	-$960	-8.9%
100 MWh	$11,793	$11,543	$11,308	$11,043	$10,805	-$988	-8.4%
110 MWh	$12,765	$12,512	$12,271	$11,997	$11,749	-$1,016	-8.0%

Small Business ToU interval network charge- estimated annual NUOS charge based on customer usage (real 2018-19)



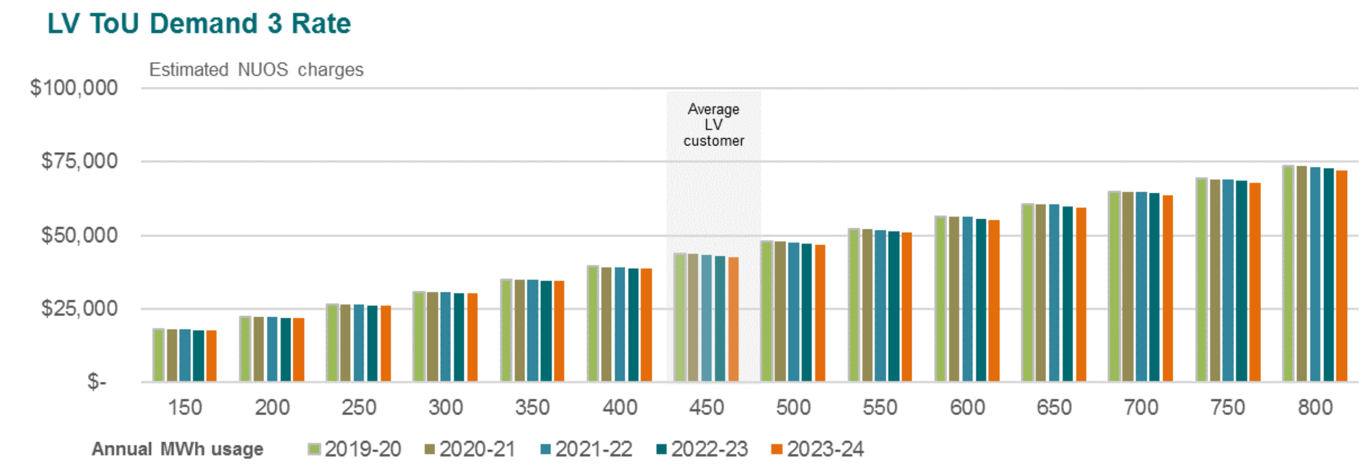
Annual customer usage	2019–20	2020–21	2021–22	2022–23	2023–24	Total $ change over the period	% Change over the period
10 MWh	$1,445	$1,439	$1,432	$1,420	$1,409	-$36	-2.5%
20 MWh	$2,383	$2,369	$2,355	$2,330	$2,308	-$75	-3.1%
30 MWh	$3,321	$3,300	$3,277	$3,241	$3,207	-$113	-3.4%
40 MWh	$4,258	$4,230	$4,200	$4,151	$4,107	-$152	-3.6%
50 MWh	$5,196	$5,161	$5,122	$5,062	$5,006	-$190	-3.7%
60 MWh	$6,134	$6,091	$6,045	$5,972	$5,906	-$229	-3.7%
70 MWh	$7,072	$7,022	$6,967	$6,882	$6,805	-$267	-3.8%
80 MWh	$8,010	$7,952	$7,889	$7,793	$7,704	-$306	-3.8%
90 MWh	$8,948	$8,883	$8,812	$8,703	$8,604	-$344	-3.8%
100 MWh	$9,886	$9,813	$9,734	$9,614	$9,503	-$383	-3.9%
110 MWh	$10,824	$10,744	$10,657	$10,524	$10,402	-$421	-3.9%

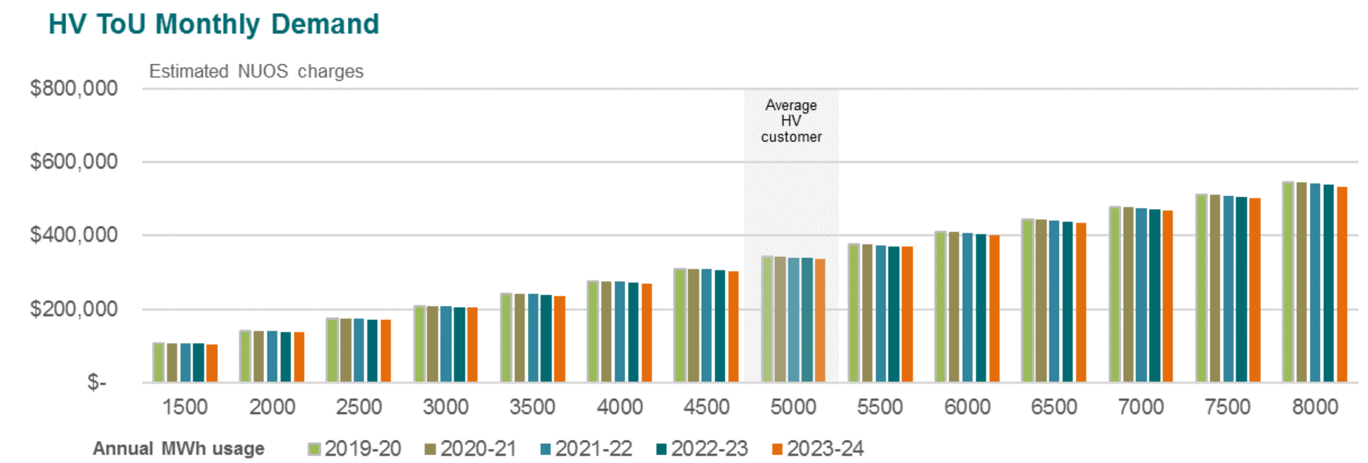
Small Business demand network charge- estimated annual NUOS charge based on customer usage (real 2018-19)

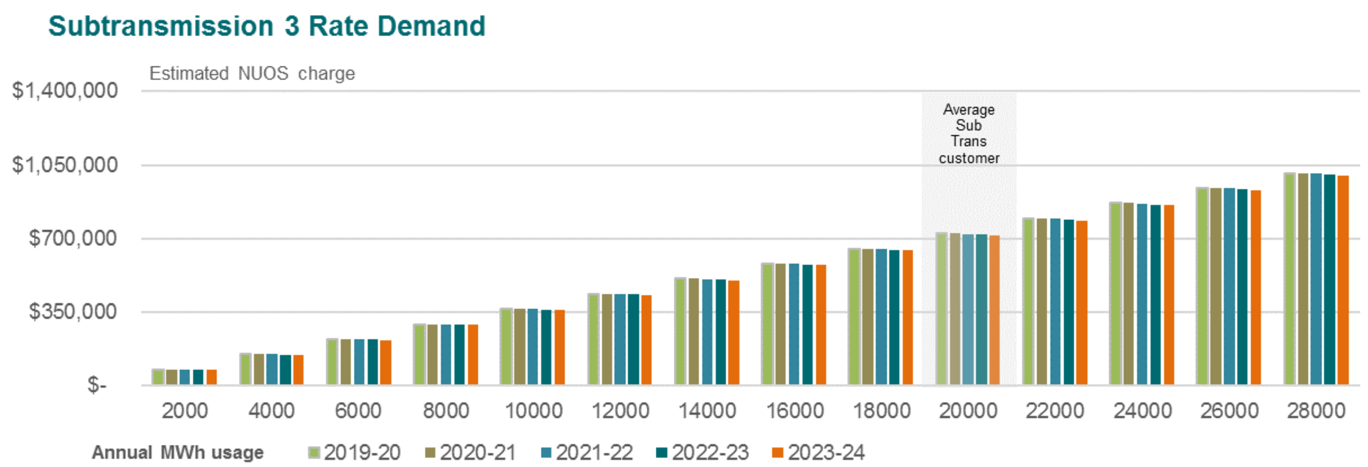


Annual customer usage	2019–20	2020–21	2021–22	2022–23	2023–24	Total $ change over the period	% Change over the period
10 MWh	$1,047	$1,067	$1,090	$1,113	$1,143	$96	9.2%
20 MWh	$1,587	$1,626	$1,670	$1,717	$1,776	$189	11.9%
30 MWh	$2,127	$2,184	$2,250	$2,321	$2,409	$282	13.3%
40 MWh	$2,667	$2,743	$2,830	$2,925	$3,043	$376	14.1%
50 MWh	$3,207	$3,302	$3,411	$3,529	$3,676	$469	14.6%
60 MWh	$3,747	$3,861	$3,991	$4,133	$4,309	$562	15.0%
70 MWh	$4,287	$4,419	$4,571	$4,737	$4,942	$656	15.3%
80 MWh	$4,827	$4,978	$5,151	$5,341	$5,576	$749	15.5%
90 MWh	$5,367	$5,537	$5,731	$5,945	$6,209	$842	15.7%
100 MWh	$5,907	$6,096	$6,311	$6,549	$6,842	$936	15.8%
110 MWh	$6,447	$6,654	$6,892	$7,153	$7,476	$1,029	16.0%

Large Business annual network charges by voltage level by year







Residential and Small Business customer with and without solar

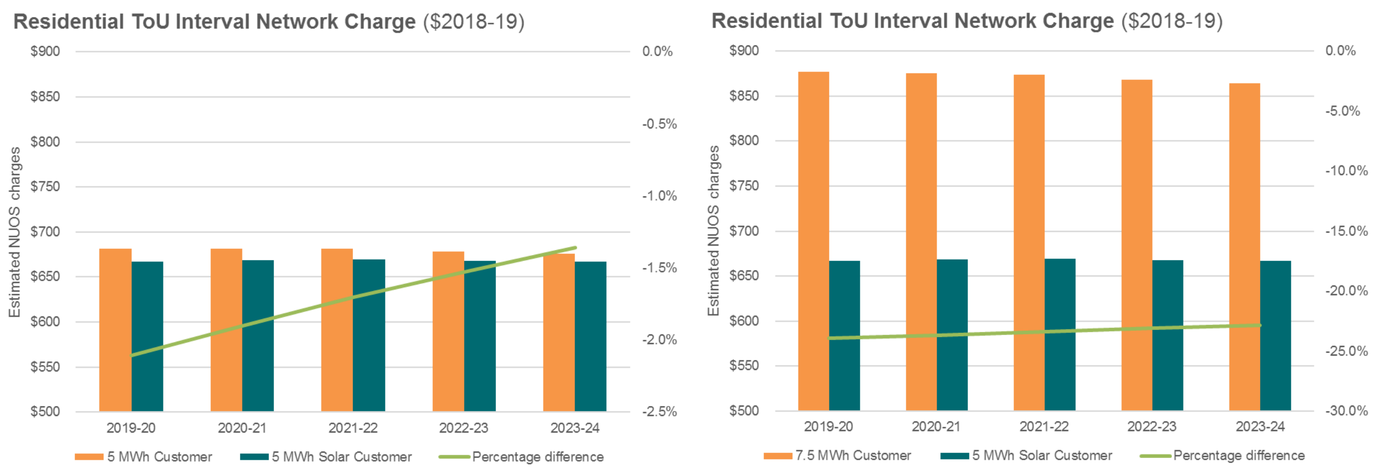
Almost 20 per cent of our Residential and Small Business customers have solar installed. Although these customers contribute almost as much to our peak demand as customers without solar, their annual network charges for consuming the same amount of electricity from the grid are lower.

Load profile of Residential and Small Business customers with and without solar

As most solar customers now have net metering, it is no longer possible to compare their annual network charges on a like-for-like basis. The below graph on the left compares a 5MWh Residential customer without solar and one with solar. Despite the identical consumption, the solar customer pays less due to lower usage of the network, predominantly during the shoulder period.

The below graph on the right compares a Residential customer with solar using 5MWh and a Residential customer without solar using 7.5MWh. This analysis assumes that both customers consume 7.5MWh but the customer with solar only consumes 5MWh of the 7.5MWh from the network. Despite a reasonably equivalent contribution to peak demand by both customers, the network charges are significantly different.

Residential customer with and without solar with year on year change



Our proposed transition ToU prices will increase the peak energy component rate for our ToU network charge over time. The difference in the annual network charge between customers with and without solar, using the same amount of energy from the network, will move closer to the same level. This ensures that customers with solar are contributing more to the actual cost of having a network connection than they have in the past.

6 Technology-neutral Network Charging Assignment

What did we propose?

While all new customers will have a default pricing assignment for their customer type, most new (and existing customers) can choose between alternative network charges if they meet the eligibility criteria. From time to time, we will reassign customers when their characteristics or level of energy consumption changes.

Our Proposed TSS put forward the assignment to a ToU charge with a demand component for all Residential and Small Business customers connecting new technology to our network (e.g. solar, batteries, electric cars) This was intended to manage peak demand. Our Proposed TSS included the ability for these customers to opt-out to just a ToU charge.

AER's Draft Determination on our Proposed TSS

The AER did not approve Essential Energy's proposed new technology connections network charge assignment policy. Instead it:

> clearly stated a preference for a technologically-neutral TSS;
> requested that Essential Energy assign network charges to Residential and Small Business customers with and without technology in the same way; and
> believed the approach we proposed was more difficult for customers to understand.

The AER also deemed our ToU network charge to be cost-reflective. Its own analysis found no clear advantage to adopting demand-based network charges over ToU network charges on our network.

What do our customers and stakeholders think?

Stakeholders were generally supportive of having cost-reflective network charges and believed that customers should be treated the same. The suggestion was that ideally, everyone with a new meter should be put on a cost-reflective network charge, regardless of whether they had new technologies or not, but that eventually they would have to be moved to more cost-reflective network charges.

However, the structure of cost-reflective network charges was heavily debated.

> Demand-based network charges were viewed as preferable by several stakeholders.
> Some stakeholders supported ToU network charges because they are easier for customers to understand compared to demand-based network charges.
> There was concern among agricultural stakeholders, that irrigators and farmers would not be able to alter their usage patterns in response to cost-reflective network charge structures.
> There was a view from a few stakeholders that there should be safeguards in place for vulnerable customers. Some stakeholders stated that some customers do not have access to the appropriate tools, such as an app or portal, to provide them with the information they need to make an informed decision.
> Feedback from retailers and some stakeholders included that a demand charge is not necessary as excessive demand is not currently an issue for Essential Energy.
> A stakeholder believed demand is a generation issue and not an issue for a regional electricity distributor.

Stakeholder feedback was also that the pricing signal from assignment to cost-reflective network charges may not reach the customer directly. Rather, it was the responsibility of the retailer to work with customers to align the interests of customers, retailers and the network.

Customers who attended our community deliberative forums mostly expressed a view that those connecting new technologies should not be treated differently to other customers, as they did not want them to be particularly advantaged or disadvantaged. This sentiment was largely driven by a fear of demand-based pricing due to the punitive approach the charging structure offers customers.

Although it was thought to be important to encourage new technology uptake, it was also thought to be important not to disadvantage those for whom it is not possible, e.g. those who cannot afford it or who are renting. Additionally, there was concern about making the system more complicated by having different charges for those with new technologies.

"The main point is that solar and battery customers shouldn't be penalised. We want to encourage people to use this technology."

Dubbo customer

"It shouldn't be automatic that they get put on a different tariff – it should be negotiable"

Wagga Wagga customer

Some also reacted against the automatic assignment element, advocating consumer choice in network charges, whereas others preferred that network charges were chosen automatically if the decision was based on what is best for the customer in terms of cost.

Overall, only 30 per cent of participants thought we should treat customers differently. Most people wanted the system to be fair and for customers to be given clear and easy-to-understand information, so they could make a choice about network charges if they needed to.

"Yes, they should be treated differently and should be charged less. Why fork out all the money for solar otherwise?"
Port Macquarie customer

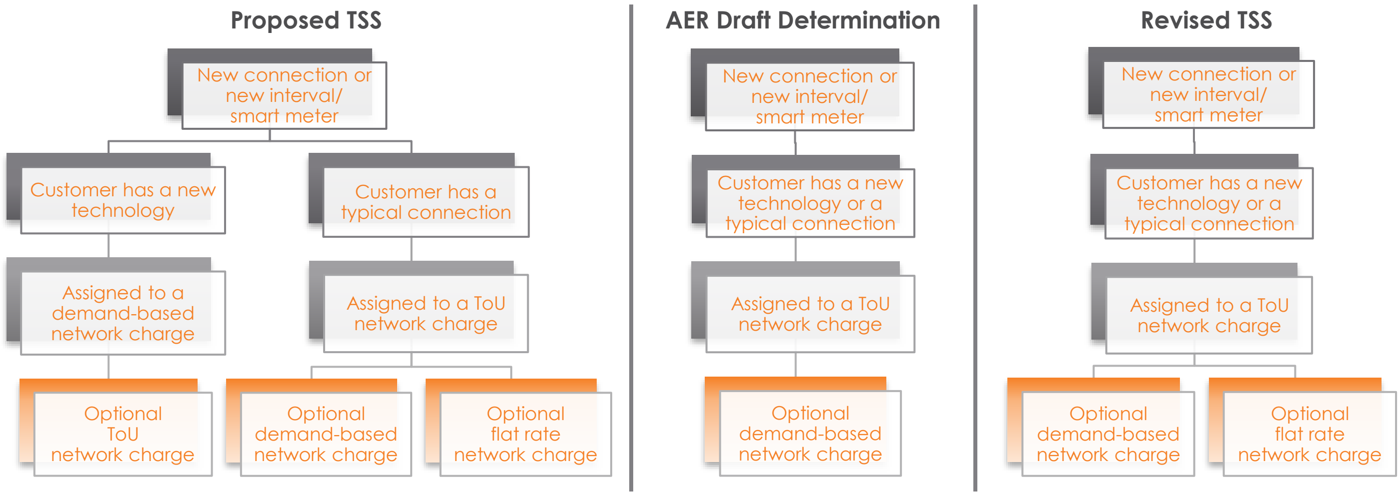
Ultimately, they wanted the industry to ensure each customer was on the retail price that provided the lowest cost for their situation.

What have we proposed in our Revised TSS?

Given the above feedback and considering the AER's Draft Determination, we propose to adjust our network charge assignment procedures so all Residential and Small Business customers default to the same network charge, and for that charge to be a ToU network charge. We have adopted this approach because:

> the AER, customers and stakeholders generally did not support assigning customers with technology in a different way to those without;
> there were opposing views on a demand versus ToU network charging approach; and
> there was a level of anxiety around the application of demand-based charges, which were considered to be overly complex.

The diagram below demonstrates the assignment approach between our Proposed TSS, the AER's Draft Determination and our Revised TSS. We also propose to maintain an optional flat price for all customers. This is discussed further in Chapter 9 - Ability to Opt Out.



7 Peak Demand Charging Window

What did we propose?

Essential Energy introduced a demand-based network charge option for Residential and Small Business customers from July 2017 which we proposed to continue throughout the 2019-24 period. The demand component for this network charge was based on a single charge for maximum demand during either peak or shoulder periods, meaning the demand charge would apply to the maximum demand registered by a customer between 7am and 10pm on weekdays.

To date, we have no Residential customers on a demand-based network charge. However, almost 300[1] Small Business customers have opted to move to this network charge.

AER Draft Decision on Proposed TSS

The AER requested that Essential Energy reconsider how the maximum demand charge was applied to Residential and Small Business customers, because:

> the broad charging window of 7am to 10pm did not send clear signals to customers on when to conserve electricity;

> our proposed approach made it more difficult for customers to respond and change behaviours; and

> it could lead to customers curtailing demand when the network was not congested because of mispricing.

What do our customers and stakeholders think?

There was considerable support among stakeholders and retailers for the demand charge for Residential and Small Business customers to be based on a peak period only.

A small number of stakeholders told us they preferred the longer window of peak and shoulder periods on the basis that it would be easier for a family or business to regulate their behaviour. A stakeholder representing agricultural customers was concerned about having a shoulder period in the morning.

Although many customers who attended our community deliberative forums did not like the idea of a demand charge, most believed it would be easier to understand and work around a shorter period, so they preferred the peak period option. They thought a longer period would mean more likelihood of being charged more. It was also believed that the goal was to move consumption out of the peak period, so it made sense to use only the peak period for measuring maximum demand.

"The idea of having Demand Pricing is to spread the load more. So if they measure it only between 5pm to 8pm, then people will be encouraged to move their load into the earlier periods. That's what they want."

Wagga Wagga customer

"The smaller window is a fairer option – if it was over the whole day then it may end up penalising you if you've moved your demand to the middle of the day."

Dubbo customer

What have we proposed in our Revised TSS?

Given the strong preference for a shorter peak demand charging window, we propose to reduce the peak demand charging periods from the current 7am to 10pm on weekdays to 5pm to 8pm on weekdays.

We also propose to maintain using a single monthly maximum demand charge for our Residential and Small Business customers because:

> our pricing working group provided overwhelming support for a monthly demand charge based on the single highest demand any time in that month[2];

> it is consistent with the methodologies adopted by other distributors for Residential and Small Business customer demand charges; and

> the maximum load a Residential or Small Business customer places on the network in any 30-minute period during the month reflects their contribution to the peak demand of the network and is therefore reflective of the costs.

[1] As at 30 November 2018

[2] Essential Energy Pricing Consultation, Pricing Working Group Report 15 November 2017, p.14 (Attachment 4.5 to our Regulatory Proposal)

Reducing the peak demand charging window presents some challenges around managing customer impact. The shorter demand charging window leads to a higher rate being charged than with a longer charging window because the LRMC is recovered over a shorter charging window. To maintain the revenue recovery required for the demand component, the per unit cost of maximum demand increases.

We analysed the impact of changing the charging window for approximately 250 Small Business customers who have opted in to this demand-based network charge. Our analysis demonstrated that:

- all small businesses currently on this network change would be better off;
- the revenue we received from the Small Business customer demand-based network charge would reduce by six per cent;
- the maximum demand charge would need to increase by 24 per cent to ensure we recovered the same revenue; and
- other changes to the Small Business demand-based network charge would be required to ensure customers were not adversely impacted.

In implementing a shorter peak demand charging window while managing the impact on our small business customers, we propose to:

- leave the demand charge component at the LRMC level; and
- gradually increase the residual costs allocated to the energy usage components by 20 per cent each year until we recover the same amount of revenue as we do now with the wider demand charging window. This five-year transition will reduce the financial impact on customers who are already on this network charge, while making it attractive enough to continue to encourage other Small Business customers to adopt it.

8 Timing of Network Charge Assignment

What did we propose?

Essential Energy introduced default assignment to ToU network charges for new residential and small business customers and customers who have a meter upgrade from 1 July 2018. We proposed that the same assignment policies apply throughout the 2019-24 period.

AER Draft Decision on Proposed TSS

The AER determined that our ToU network charge is cost-reflective and an appropriate default tariff. However, it recommended we provide customers who receive a new interval meter, without changing their location or connection, with a 12-month data-sampling period to:

> help them understand their network charges and how they can change behaviours to reduce network charges; and

> make a more informed choice about retail tariffs.

What do our customers and stakeholders think?

There were mixed views among our stakeholders and customers.

Some stakeholders indicated a preference for a move to a cost-reflective network charge when the smart meter was installed. This was because a delay in network charge reassignment also leads to a delay in customers receiving the associated benefits. There were also concerns about the practicality and feasibility of introducing a 12-month delay.

Some retailers supported an immediate move to a cost-reflective tariff, while others thought that customers should be able to choose whether to adopt a more cost-reflective network charge within a 12-month period of changing their meter, and that having the smart meter data for 12 months would help to inform this decision. A small number of stakeholders believed in theory it would be good to have 12-months of data to make an informed decision before changing the network charge, but it wasn't clear how the AER would make this option work and how information would be provided to customers during the 12-month period.

A very small number of retailers believed that customers should not be reassigned immediately as they do not have enough data to inform their choice. A few stakeholders expressed the view that replacement of a faulty meter should not trigger a network charge reassignment.

Retailers and a few stakeholders suggested a modified approach. This would involve immediate reassignment to a ToU network charge following a meter upgrade (as proposed by Essential Energy) but introduce a 12-month post-implementation review to assess the impact on customers.

Customers who attended our community deliberative forums also had mixed views about whether customers should be moved to new pricing structures as soon as a smart meter was installed, or whether there should be a 12- month period before any changes occurred. Some wanted to be able to take immediate advantage if there were cost savings whereas others wanted to have 12-months of usage data first.

Many people thought the best outcome was a choice between immediate switchover or waiting 12 months, based on information and advice from the retailer. They also wanted the ability to switch at any point during the 12 months rather than waiting until the end of the period.

"If I see that I would be better off on the new tariff I would be annoyed that I then have to wait 12 months before I save any money."
Dubbo customer

"I'd like to wait 12 months so that I can actually see that it will be better for me before it happens."
Wagga Wagga customer

"I don't think it should be one or the other. They should give you the option – a choice. With information given"
Wagga Wagga customer

What have we proposed in our Revised TSS?

Essential Energy proposes not to adopt the AER's recommendations in this case based on:

> feedback from our stakeholders and customers, which was mixed, with no clear preference;

> our experience of customer reassignments to date;

> the future financial impact on customers of maintaining our current approach to reassigning customers to a ToU network charge following a meter upgrade;

> our assessment of the practical issues of implementing the AER's recommendations; and

> a post-reassignment review of customer outcomes once 12-months of data is available will provide greater benefits to most customers.

8 Timing of Network Charge Assignment

Our actual experience so far has not highlighted any concerns with our current network charge reassignment procedures. From 1 July 2018 to the end of November 2018, almost 11,000 customers had their meter upgraded to a smart meter or were new customers connecting to the network for the first time. They have all been assigned to ToU network charges and fewer than 100 chose to opt out to a less cost-reflective network charge – our flat rate network charge. This represents less than one per cent.

In addition, more than 3,000 greenfield sites connected to our network and are on interval ToU network charges.

Our analysis of the financial impact on customers shows that over 99 per cent of the 14,000 customers are better off on the newly assigned ToU charge compared to the previous flat rate network charge. The table shows that all Residential customers on our interval ToU network charge are better off compared to our flat rate 'Anytime' network charge.

Existing Residential customers on ToU network charges are no worse off

Benefit to Residential customer with ToU network charge	Customer numbers
No change	1,210
Better off up to 10%	6,750
Better off up to 20%	5,498
Better off up to 40%	637
Total Residential ToU customers	**14,095**

However, 129 Small Business customers are worse off (24 per cent) on the interval ToU network charge, as they have very little consumption during the off-peak period. Some sites have only three per cent of their consumption during these periods, compared to an average of around 54 per cent.

Existing Small Business customers on ToU network charges

Customer Size	Benefit to Small Business with ToU network charge	Customer numbers	Average annual amount of network charges
Customers Less than 5MWh	Better off	7	$908
	Worse off up to 20%	52	$842
	Worse off up to 50%	70	$621
Customers Greater than 5MWh	Better off up to 40%	4	$10,646
	Better off between 20% and 40%	291	$6,835
	Better off up to 20%	114	$2,589
	Worse off up to 5%	7	$1,226
Total Small Business ToU customers		**545**	

The tables support continuing our current practice of assigning customers to our interval ToU network charges and allowing them to opt out if they choose.

When it comes to the practical implementation of the AER's recommendation, it would introduce complexities that required careful thought, consideration and clear communication of who was accountable for providing customers with information.

Our assessment identified some issues:

- The AER's recommendation would slow the move of customers to cost-reflective network charges in line with the network pricing objectives.
- While duplicate billing information would be beneficial, it is not clear how customers would receive the information and how they would be informed of how to interpret the comparison.
- The roles played by the distribution network and retailer in providing duplicate information would be unclear.
- In almost every case, a 12-month sampling period would delay financial savings for customers (as demonstrated in the tables), leading to customer complaints.
- Significant administrative processes would be required to keep track of these changes, for both Essential Energy and retailers operating in our network area.
- Customers and retailers would not have a clear trigger point for the change of network charge.
- Post-implementation processes provide a simpler and cheaper alternative without sacrificing the best overall customer outcome.

9 Ability to Opt Out

What did we propose?

After hearing from our customers and stakeholders that choice was important, we developed a Proposed TSS that included various options for Residential and Small Business customers without technology, including the ability to opt out of a cost-reflective network charge and opt in to a flat rate network charge.

AER Draft Decision on Proposed TSS

The AER determined that in order to make greater progress towards the network pricing objective, customers should not be allowed to opt out of cost-reflective network charges in favour of a flat rate network charge.

What do our customer and stakeholders think?

Stakeholders' views were mixed.

Several stakeholders expressed the view that customers should be able to opt out of cost-reflective tariffs. Some retailers felt that customers should be given the right to choose. A number of stakeholders wanted more time to consider this question.

Some stakeholders did not think there should be an option to opt out of cost-reflective network charges on the basis that network charges are for retailers, not customers, and it is the responsibility of retailers to help customers manage their costs.

A small number of stakeholders expressed the view that the network charges offered should be cost-reflective and customers should be given the choice to opt-out so long as the flat network charge was more expensive than ToU or demand-based network charges. They also suggest it provided 'insurance' to the worst-affected customers.

A small number of stakeholders were in favour of flexibility and choice for customers. Feedback from a charitable organisation was that the message should be that a flat network charge is now a legacy charge and customers now have more choice in network charges. Also, customers may value an option between a higher smoother bill and an incentive to opt out and go to a more cost-reflective network charge.

Although some stakeholders appreciated the AER's views about opting out, in practice, they believed it was necessary to provide choice and flexibility. However, they assumed that it would be more expensive than cost-reflective network charges.

Customers who attended our community deliberative forums indicated strongly that they should have the option to revert to their former pricing structure if the cost-reflective network charge was disadvantageous for them.

However, for most forum participants the idea of choice was the basis of their preference.

"It takes away the choice, so you should be able to opt out."
Wagga customer

"Should have the option. If you are disadvantaged, you would want to know that you can move back to what you were previously on. They shouldn't be able to force you to be worse off"
Wagga customer

"The more choice you give customers the better it is for them."
Dubbo customer

"It's about having choice. As a customer I want to have that choice to move to a tariff that best suits me"
Port Macquarie customer

"If you think about a young working couple in a regional town like this. They have to do things at set times, and don't have much choice. They can't alter when they cook for their kids or do the washing, and if you lived in this area you'd know there's little choice but to turn the air conditioner on as soon as they get home"
Dubbo customer

"Absolutely – good to have an exit strategy – people will feel that they can try it"
Dubbo customer

What have we proposed in our Revised TSS?

Most stakeholders and customers support our current practice of allowing customers to opt-out of cost-reflective network charges to a flat rate network charge. Our forum participants wanted this to continue. Given this feedback, we propose to maintain the ability for customers to opt out of our ToU network charge to a flat rate network charge.

This is an important part of all measures in our Revised TSS, because:

> it ensures customers have the choices they have requested us to provide;

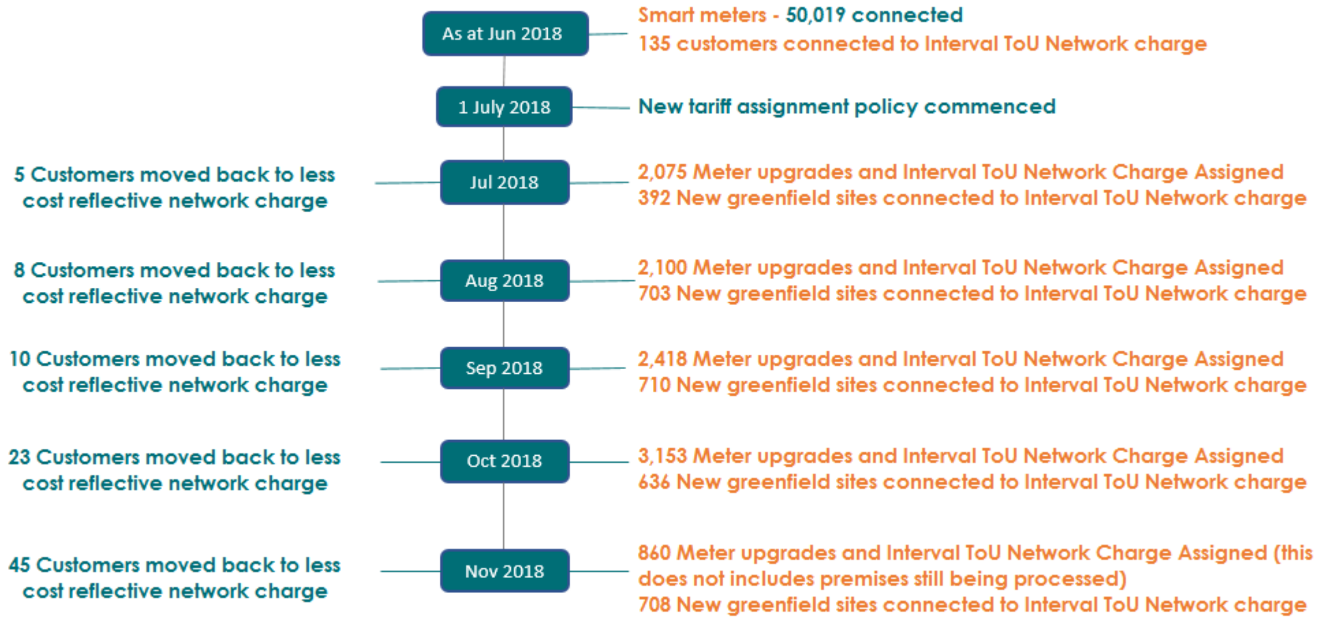
> it minimised the price shocks that may occur for a very small number of customers;

> it works in conjunction with our reassignment procedures for meter upgrades by protecting adversely affected customers; and

> allocating a larger proportion of residual costs to our less efficient charges means our flat rate network charges will be less attractive, providing an incentive for customers to stay on cost-reflective network charges.

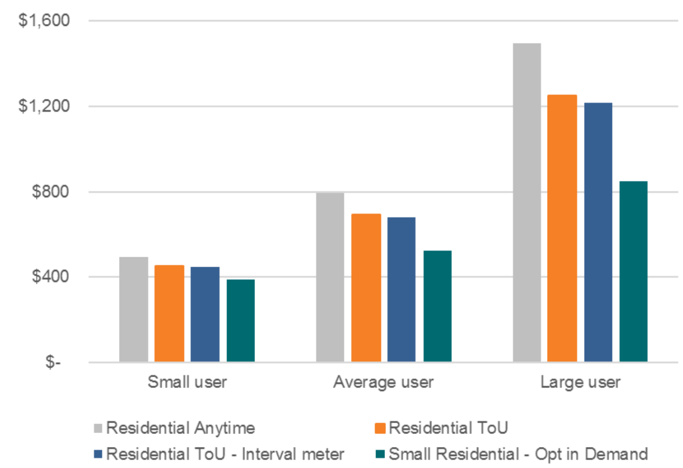
Our experience to date shows that the opt-out provision has been taken up by a very small number of customers. This suggests it is only being exercised in very limited circumstances.

Since 1 July 2018, almost 11,000 customers have been assigned to our new ToU network charge for interval meters, with fewer than 100 choosing to opt out to a less cost-reflective network charge, less than one per cent. This does not suggest that progress to the network price objective is in jeopardy.

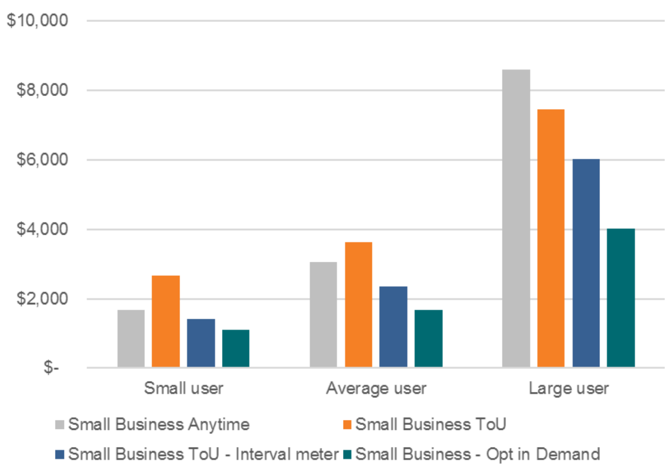


Our flat rate network charges are the least attractive of our network charges and our most cost-reflective opt-in Demand prices are the most attractive. Opt-in network charging options during 2019-24 are shown in the graph. Total bill amounts are averaged over the 2019-24 period.

Households (Real 2018-19)



Small Businesses (Real 2018-19)



10 Other Issues

In making their Draft Determination, the AER highlighted other areas of our Proposed TSS that required further explanation and detail. In addition, several stakeholders queried aspects of our Proposed TSS.

Varying levels of fixed charges for Small Business

Historically, Essential Energy and its predecessors charged different fixed charges for Small Business customers if they were on a:

> flat rate network charge;

> Small Business ToU network charge and consuming less than 100MWh a year; or

> Small Business ToU network charge and consuming more than 100MWh a year.

These network charges were set to encourage Small Business customers to move to the more cost-reflective network charge once they were consuming around 40MWh a year. This level of consumption was often used as a trigger point for alternative prices by various networks and retailers.

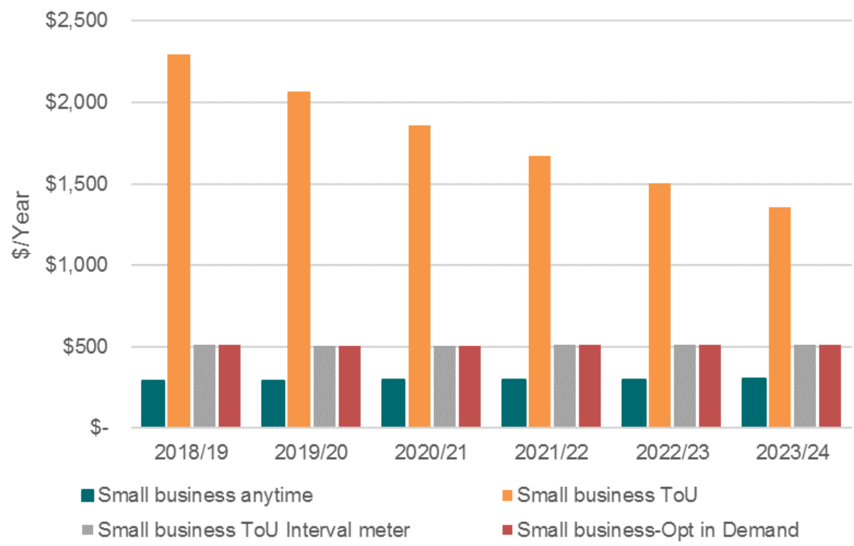
The higher fixed component of these charges reflected the fact that businesses generally required a greater load from the network and the underlying costs to supply them were, therefore, higher. We now recognise that Small Business customers do not contribute more to the peak demand on our network than Residential customers and we have been slowly transitioning the fixed component down to a level that is more closely aligned with Residential customers. The ToU network charge we introduced for Small Business customers with interval/smart meters from 1 July 2018 is set at a cost-reflective level.

If we changed the fixed component of our Small Business ToU network charges to the same level as our interval/smart meters ToU charge in one step, it would lead to an average change in fixed charges for all other customers increasing by almost eight per cent. Therefore, the transition must happen slowly. We are reducing the higher fixed charges by 10 per cent a year over the 2019–24 period.

Our new ToU and demand-based network charges for Small Business with interval/smart meters are priced to encourage all Small Business customers to move to them, and our policy of assigning all new Small Businesses and those who get a meter upgrade to the cost-reflective ToU network charge will help with this transition.

The graphs show how this transition of fixed charges is evolving over the next five years. The prices are in real $2018-19 and will differ with inflation each year.

Small Business fixed charge component by network charge and year 2019–24 ($ real 2018-19)

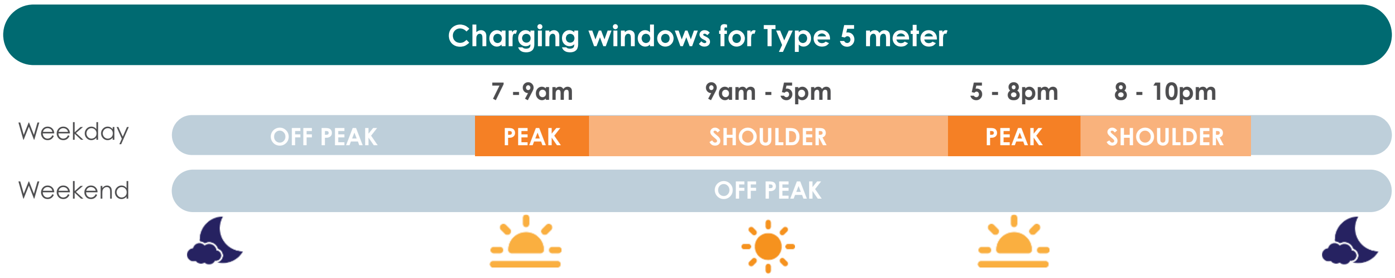


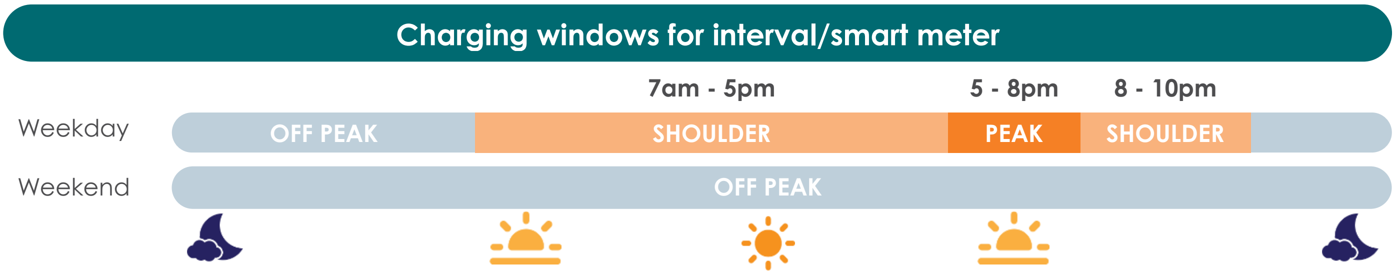
Charging windows vary by meter type

ToU charges are consumption charges based on charging windows that we have developed to provide customers with accurate signals of network congestion and costs. Our ToU charging windows for consumption and demand charges are set to different time windows depending on the type of meter a customer has.

> Basic accumulation meters (Type 5 meters) cannot be cost-effectively reprogrammed, so they still record a morning peak between 7am and 9am on weekdays as this is how they were programmed when they were installed. We would have to visit every household with a Type 5 meter and manually reprogram them to remove the peak. This morning peak also applies to our obsolete charges (historical charges that are not cost-reflective and not available to new customers).

> This morning peak does not apply to interval/smart meters as the data is recorded in 30-minute intervals and the meters can easily be remotely reprogrammed with new time period.





Consistency in network charges between NSW distributors

Both the AER and some stakeholders have indicated that consistent network charge structure between NSW distributors would be preferable so long as it is cost-reflective as it would make it easier for customers to understand their electricity charges.

We certainly agree with this idea in principle and held discussions with both Ausgrid and Endeavour Energy following the publication of the AER's Draft Determination on this particular topic. We specifically looked at whether there was any consistency between NSW distributors':

> charging windows;

> network charging structure for Residential and Small Business customers; and

> network charge assignment policy.

At this stage, we have moved our network charge structures closer together with the removal of a demand charge in the shoulder window for our Small Business customers.

However, both of the other NSW distributors have implemented seasonal network charges, that do not feature in our network charge structures. Seasonal network charges were not at all supported by our stakeholders during our consultation undertaken for our previous TSS. They were seen as adding unnecessary complexity for customers.

In addition, our seasonal load profiles do not align with the other NSW distributors given our geographic and climatic differences. As such aligning our charging windows would give rise to network charges that were not reflective of our efficient costs and would not meet the requirements of the NER.

In the absence of more uniformity in our network loads, there is limited ability for more consistency between network charges at this stage. We will, however, continue to work with the other NSW distributors over the 2019-24 period to see if there are other areas where we improve consistency, for example in areas such as terminology, the format of pricelists and definitions. We will reconsider opportunities in this area as part of our 2024-29 regulatory proposal.

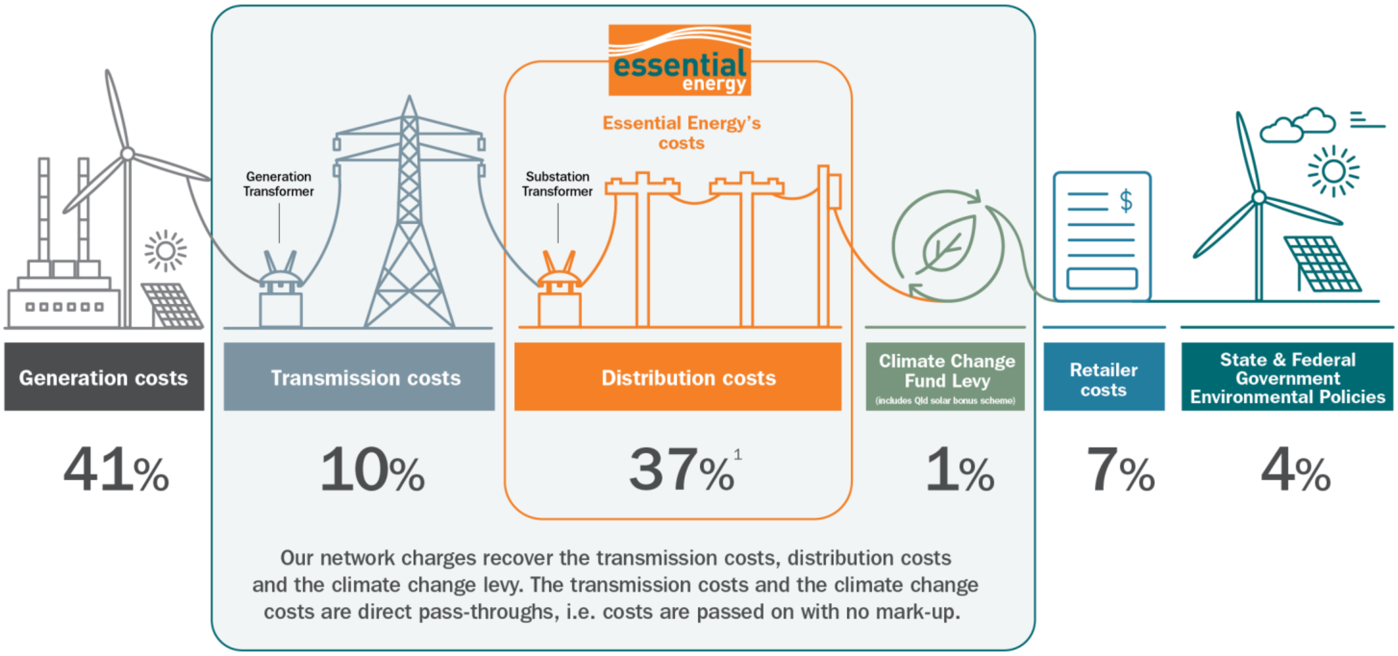
Annual Pricing Proposals

The AER Draft Determination requested that we provide greater certainty and clarity on our approach to setting prices through our annual Pricing Proposals.

Our NUOS charges include Essential Energy's distribution network costs as well as recovery of two additional components:

> Transmission costs, from TransGrid and Powerlink for operating the transmission networks, which we pass on directly to customers with no mark-up; and

  > the Climate Change Fund Levy and contributions to the Queensland Solar Bonus Scheme, which we also passthrough to customers with no mark-up.



The Indictive NUOS Pricing Schedules provided with our Revised TSS have prices for each network charge for each year. The indicative network charges include forecast recovery of transmissions costs, distribution costs and the Climate Change Fund Levy. While we will maintain the same general approach to setting network charges each year, as those included in our Indictive NUOS Pricing Schedules, the overall average network change may differ (either increase or decrease) as a result of these events:

> the AER's final distribution determination for Essential Energy for the 2019-24 regulatory period;

> changes arising from pass-through events approved by the AER;

> transmission costs and the Climate Change Fund Levy passed through to Essential Energy;

> sales volumes varying from forecast levels, leading to an under-recovery or over-recovery of revenue that impacts the following year's prices;

> differences between forecast customer numbers, energy and demand included in our TSS and any updated forecasts made at the time of each annual Pricing Proposal;

> annual updates to the cost of debt that take place at the time of the annual Pricing Proposal, in line with the AER's Rate of return Guideline;

> changes in the CPI rate as forecasts become actuals; and/or

> application of incentive schemes as approved by the AER.

The approach to how we will make adjustments to the various components are summarised in the table below.

[1]Based on the 2017–18 forecast, Australian Energy Market Commission, 2017 Residential Electricity Price Trends, 18 December 2017 p. 100

Changes to network charges in annual Pricing Proposals.

Component	Network charge Type	Annual update
Distribution use of system (DUoS) charges	ToU distribution network charges	Differentiate peak and shoulder rates by applying: > a 2 per cent increase to the peak component; and > a 2 per cent decrease to the shoulder component each year.
	Residential and Small Business customers	Apply the $5 increase to the fixed charge then apply the average percentage increase/decrease in revenue to each of the fixed charge, consumption and demand components.
	LV ToU <100 MWh and >100MWh	Apply a 10 per cent decrease to the fixed charge to transition this component down to same fixed rate charge as other Small Business customers.
	Small Business Opt-in Demand	Apply a 20 per cent increase to the energy consumption components to take into account the removal of the shoulder period from the demand component put forward in our Revised Proposal and Revised TSS.
	Obsolete distribution network charges	To incentivise customers to move to more cost-reflective distribution network charges: > if there is an increase in overall DUoS prices, the percentage increase in revenue is doubled for obsolete distribution network charges; and > if there is an overall decrease to DUoS prices then rates are held flat.
	All	Average increase or decrease to recover required revenue, including adjustment for any over-recovery or under-recovery.
Transmission use of system (TUoS) charges	Site specific	Actual rates applied as provided by transmission companies
	All other	Average increase to recover required revenue, including adjustment for any over-recover or under-recovery.
	Time of Use network charges	Differentiate peak and shoulder rates by applying a 2.5 per cent increase to the peak component each year
NSW Climate Change Fund Levy	All	Average increase or decrease to recover required revenue, including adjustment for any over-recovery or under-recovery, with only 25 per cent from Residential customers.
Queensland Solar Scheme	All	Average increase or decrease to recover required revenue, including adjustment for any over-recovery or under-recovery.

Apart from the direct pass-through of TUoS charges to large customers on site specific network charges (detailed in the following section), any changes to the amount of TUoS to be recovered each year through the annual Pricing Proposal process will generally be applied to each network charge uniformly.

The recovery of jurisdictional scheme amounts such as the NSW Climate Change Fund Levy and the QLD solar scheme will also be given the same percentage price change each year, while conforming to any Government requirements such as only recovering 25 per cent of the NSW Climate Change Fund Levy from residential customers.

Setting site-specific prices

Essential Energy has 23 very large sites on site-specific prices. We generally calculate these prices by identifying all assets between the customer connection point and the transmission connection point. This means we only identify the assets that are used to provide the site with an electricity supply. We also consider whether these assets were paid for by the customer. The replacement value of these assets as a proportion of the value of our total asset base is calculated then applied to the amount of our annual revenue allowance to derive the amount of DUoS charges we will recover from that customer.

Alternatively, we may look at the customer's demand (or forecast demand for a new customer or proponent) as a proportion of the total demand on that section of our network (from the transmission connection point). This proportion is then used to work out their contribution to our annual distribution revenue. This method is more suited to new sites or sites looking to trial alternate energy supply such as microgrids.

Unless there is a significant change to the customer's load or the assets, the DUoS component of the overall distribution network charge for these site-specific charges changes annually in line with the overall percentage change in revenue to be recovered.

TUoS charges are a direct pass-through cost and are charged to each site using the same method, rates and components as transmission companies use to charge us. They are typically the largest component of the total network charge for site-specific customers and are adjusted annually to reflect the AER-regulated prices that transmission companies charge us.

These sites are also charged a small amount toward our contribution to the Climate Change Fund. This is applied as a cents per kWh charge and is lower than for other business customers to recognise that these large sites already contribute to various environmental schemes.

How do site-specific prices differ from subtransmission tariffs?

Site-specific distribution network charges are calculated individually, and the related TUoS charges are directly passed through. These can differ substantially, depending on the section of network to which the customer is connected but generally form most of the total network charge.

Our general subtransmission network charge is an average for all other customers connected at the subtransmission voltage level. The DUoS component of their charge is based on LRMC for the demand components and an allocation of residual costs for the fixed and energy components.

The TUoS rates are also averaged for this customer class and reflect the voltage level at which they are connected. Again, this differs from the approach for site-specific customers.

Education

The one theme that has come across consistently in all our customer and stakeholder engagement is that customers want to understand their electricity bills better. They consider electricity supply and how it is billed as a very complicated area.

Our education program started with a project in 2016-17 to move customers consuming over 160MWh a year to the appropriate demand-based tariff. We held several workshops with impacted customers and provided brochures and individual letters.

As outlined in Chapter 4, we continued this journey during the four phases of engagement for our Proposed and Revised TSS. Many customers attended three different forums and became more educated about the electricity supply chain, how network charges are structured and what the different types of network charges are. Even so many still found it challenging to understand.

We have developed Plain English brochures to explain ToU, demand and controlled load network charges and placed them on our website: https://www.essentialenergy.com.au/our-network/network-pricing-and-regulatory-reporting/tariff-change https://www.essentialenergy.com.au/our-network/network-pricing-and-regulatory-reporting/tariff-change

We have also developed a short video to explain how demand charges work and why they provide efficient pricing signals. https://www.youtube.com/watch?v=_4n1HyVelgo https://www.youtube.com/watch?v=_4n1HyVelgo

We are committed to providing on-going education as the energy market continues to evolve and will be working closely with stakeholder and customer groups when trialling new forms of network charges over the 2019-24 period.

11 The Future

Corporate Strategy

The Revised TSS and TSES align with our Corporate Strategy, which provides a road-map for Essential Energy's future direction. It informs our activities and investment for the next 10 years and will ensure we can continue to meet our customers' changing needs.

It is important that our business can adapt to the future energy market, whatever form it may take. As such, our Strategy does not dictate a particular future state. Instead, it provides a pathway to ensure we will always be ready for change and capable of providing the services our customers require.

To develop the Strategy, we identified the distribution network capabilities required to deliver the future services customers may demand. This involved determining which areas of Essential Energy already support our goals, those needing further development, and new areas to consider. Business transformation emerged as our major priority.

Our Corporate Strategy

What we are doing longer term

The future design of our network charges will continue to be aligned with our Corporate Strategy to be customer-focused. Our objectives for the future are to use network charges that are innovative and provide incentives for customers to connect, and stay connected, to our network.

Over the longer term, we want to design network charges that provide an accurate signal of the costs of using our network at a specific time or location. Innovative design will also allow us to better support our network. To do this, we will need to transition a larger proportion of our customer base to cost-reflective network charges.

Our Corporate Strategy will also lead to us delivering energy to our customers in new ways. This may include providing some customers with stand-alone power systems. These innovations in how we deliver energy will need to be incorporated into our network charges.

Pricing innovation

We will need to carefully manage our innovation process so changes in how we design network charges are fair and can be understood by customers.

To test the impact of new network charges we will conduct customer trials to test other pricing options such as capacity-based network charges, peak rebates and other techniques that may encourage customer response. These trials will inform our future approach to pricing design.

Trials are an important part of innovating how we design our network charges. However, trials alone will not be enough to deliver pricing innovation that is in the interests of our customers and our network. We will draw on new tools, such as behavioural economics, to understand how customers may respond to price signals and will draw on lessons from other jurisdictions about what works and what does not.

Ongoing education and customer engagement are also important for pricing innovation. We will undertake extensive engagement with customers and stakeholders throughout the trial process. We will provide our customers with the information they need to make informed decisions about the best network charging choice to suit their individual circumstances. We will try to incorporate all lessons learned so we can continually improve how we interact with our customers about pricing.

Stand-alone power systems

Outside core business transformation, there is potential to make better use of the network and reduce customer costs by altering how we deliver energy to customers on the fringe of the grid. For example, replacing long feeders that serve a handful of customers with stand-alone power systems.

We have consulted with our stakeholders on this issue. Our customers support stand-alone power systems as a solution for some customers, particularly in remote areas where the cost of supplying energy via the network is high. They expect that the use of stand-alone power systems for certain remote customers would improve reliability outcomes and reduce bills.

"If I was living in a remote area and it was suggested to me, I'd want proof that it would be equal or better than what I have."
Port Macquarie customer

Our stakeholder deep dives have told us that we should continue to explore stand-alone power systems because they are supported by customers, and we should carefully consider and assess the risks of moving some customers to these systems.

"I'd like to think this would mean my power supply would be more reliable and the bill would be less."
Port Macquarie customer

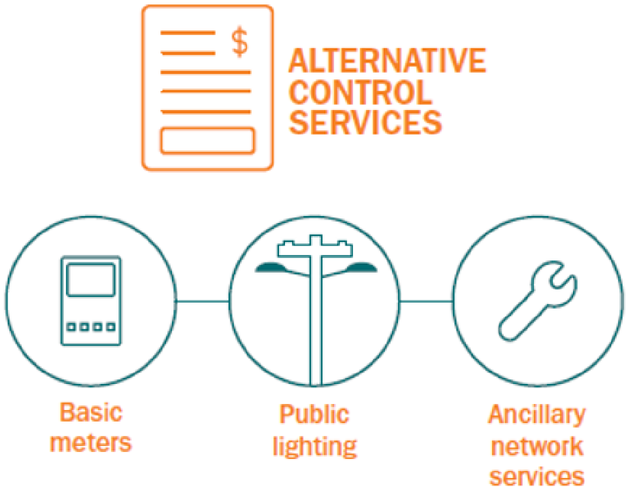
Stand-alone power systems have the potential to reduce distribution network charges. This will be our focus as we seek to deliver energy in new ways and inform how we design our network charges in the future.

12 Proposed User Pays Charges

Proposed User Pays Charges

We provide some services to individual customers on an as-needs basis and charge the user a fee. These fall into three categories:

> Ancillary Network Services;
> Metering Services; and
> Public Lighting.



For these services, we charge either an approved fee; a fee based on an approved unit rate; or a quoted fee. For more details, see these attachments:

Attachment 3 – Revised Indicative Ancillary Network Services Pricing Schedule to the Revised TSS

Attachment 4 – Revised Indicative Metering Services Pricing Schedule to the Revised TSS

Attachment 5 – Revised Indicative Public Lighting Pricing Schedule to the Revised TSS

During the TSS period, we adjust these charges each year for CPI and any approved cost increases.

Ancillary Network Services

The AER defines Ancillary Network Services as non-routine services provided to individual customers on an 'as needed basis'. Essential Energy has a monopoly on providing these services, so the AER regulates them as Alternative Control Services (ACS).

The Ancillary Network Services and categories listed in the Revised TSS are as the AER defines them in the NSW Distributors Framework and Approach commencing 1 July 2019.

Compared to our TSS for the previous regulatory period, the number of Ancillary Network Services in our TSS has increased because of:

> the AER's 2016 Ring-fencing Guideline;
> the launch of the Power of Choice reforms for contestable metering; and
> stakeholder feedback.

Our indicative prices for these services are available in Attachment 3 – Revised Indicative Ancillary Network Services Pricing Schedule to this Revised TSS.

For further details about how we have developed our prices for these services, please contact Essential Energy.

Metering Services

Essential Energy currently supplies Type 5 and Type 6 (basic) metering services to Residential and Small Business customers.

From 1 December 2017, the provision of new and replacement metering became fully contestable under the Power of Choice framework. As a result, we no longer install meters but are responsible for meter reading and maintenance activities for Type 5 and 6 meters. Whenever these meters are faulty, we refer them to retailers for replacement with a Type 4 (smart) meter, so the number of installed Type 5 and Type 6 meters is progressively declining.

When developing our Metering Services charges for our Revised TSS, we have considered the intent of the Power of Choice framework and developed cost-reflective charges. They include:

> an operational component to recover our meter reading and maintenance costs; and
> a capital component to recover the costs of meters installed before 1 July 2015.

Customers pay our metering services charges on a cents-per-day basis, and each metering charge aligns to an equivalent network price.

Our indicative charges for these services are available in Attachment 4 – Revised Indicative Metering Services Pricing Schedule to this Revised TSS.

Public Lighting Services

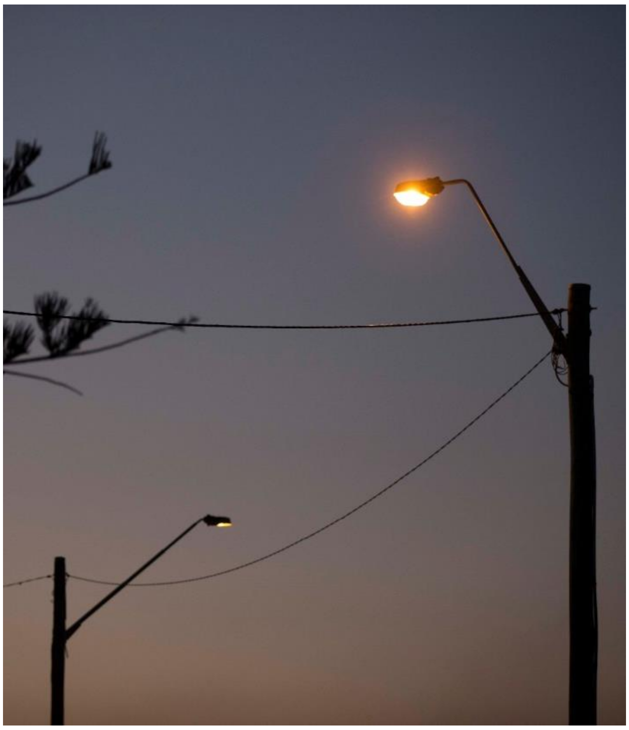
The public lighting services Essential Energy provides include maintaining and replacing public lighting infrastructure – the Street Lighting Use of System component of our services.

In response to stakeholder feedback we propose to implement component pricing during the 2019-24 regulatory period based on:

> Capital Recovery charges (only applies to public lighting installations currently on network charges 3 and 5):
  - luminaire;
  - bracket; and
  - pole.

> Maintenance (operating expenditure) charges (applies to all public lighting installations):
  - lamp; and
  - pole.

Our proposed Public Lighting Services and indicative prices are in Attachment 5 – Revised Indicative Public Lighting Pricing Schedule to this Revised TSS.



13 Compliance Checklist

Section 6.18 of the NER sets out the requirements for preparing and submitting a TSS to the AER. The table below sets out these requirements and where we have complied with them.

How to find where Essential Energy has addressed the NER's TSS requirements

Rule	Relevant 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.	Revised TSS and attachments
6.8.2 (d1)	The proposed tariff structure statement must be accompanied by an indicative pricing schedule.	Attachment 2 – *Revised Indicative NUOS Pricing Schedule of this TSS* Attachment 3 – *Revised Indicative Ancillary Network Services pricing schedule* Attachment 4 – *Revised Indicative Metering Services pricing schedule* Attachment 5 – *Revised Indicative Public Lighting pricing schedule*
6.8.2 (d2)	The proposed tariff structure statement must comply with the pricing principles for direct control services.	The entire Revised TSS 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;	Chapter 2 –*Customer Classes* in the Revised TSS
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);	Chapter 3 – *Assigning Customers to Customer Classes and Appendix A* in the Revised TSS
6.18.1A (a)(3)	(3) The structures for each proposed tariff;	Chapter 4 –*Our Network Charge Structures* in the Revised TSS
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.	Chapter 10 *Other Issues - Annual Pricing Proposals*
6.18.1A (b)	A tariff structure statement must comply with the pricing principles for direct control services.	Chapter 5 – *Our Pricing Proposal Methodology* in both the TSES and our Revised TSS

13 Compliance Checklist

Rule	Relevant requirement	Addressed in
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 – *Revised Indicative NUOS Pricing Schedule of this TSS* Attachment 3 – *Revised Indicative Ancillary Network Services pricing schedule* Attachment 4 – *Revised Indicative Metering Services pricing schedule* Attachment 5 – *Revised Indicative Public Lighting pricing schedule*
6.18.3 (b)	Each customer for direct control services must be a member of one or more tariff classes.	Chapter 2 –*Customer Classes* in the Revised TSS
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).	
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.	
6.18.4 (a)	In formulating provisions of a distribution determination governing the assignment of retail customers to tariff classes or the reassignment 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.	Chapter 5 – *Our Pricing Proposal Methodology* in both the TSES and our Revised TSS
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.	
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.	Chapter 5 – *Our Pricing Proposal Methodology* in both the TSES and our Revised 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.	

13 Compliance Checklist

Rule	Relevant requirement	Addressed in
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 subparagraphs (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).	Chapter 5 – *Our Pricing Proposal Methodology* in both the TSES and our Revised TSS
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.	
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.	Chapter 5 – *Our Pricing Proposal Methodology* in both the TSES and our Revised TSS
6.18.5 (j)	A tariff must comply with the Rules and all applicable regulatory instruments.	Chapter 5 – *Our Pricing Proposal Methodology* in both the TSES and our Revised TSS Compliance Checklist
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.	Annual Pricing Proposals
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%)	Annual Pricing Proposals

13 Compliance Checklist

Rule	Relevant requirement	Addressed in
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).	
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.	
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).	
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.	
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.	Chapter 10 - *Other Issues - Annual Pricing Proposals* Attachment 2 – *Revised Indicative NUOS Pricing Schedule of this TSS*
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.	
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.	

13 Compliance Checklist

Rule	Relevant requirement	Addressed in
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); (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.	

14 Glossary

Term	Meaning
AER	Australian Energy Regulator: national regulator for the electricity industry
Alternative Control Services	Specific user-requested services: Public lighting; Type 5 and Type 6 metering (generally Residential and Small Business customer meters); and Ancillary Network Services
Charging parameters	The specific charge characteristics for a component within the pricing structure
CPI	Consumer Price Index – a measure of inflation
Customer class	A group of customers that share a common set of characteristics that allow them to be grouped together to ensure similar customers pay similar charges
Demand charge	Charge based on the maximum amount of electricity a customer uses at any one time, measured in kW
DER	Distributed Energy Resources – refers to smaller generation units that are located on the consumer's side of the meter
Direct Control Services	Services regulated by the AER under the National Electricity Rules, comprising Standard Control Services and Alternative Control Services
DNSP	Distribution Network Service Provider
DUoS	Distribution use of system. Charge for using the distribution system
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
MWh	Megawatt hour
NEL	National Electricity Law
NER	The National Electricity Rules: these govern the operation of the national electricity market
NPV	Net Present Value
NSW	New South Wales
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 Levy
Peak demand/ peak load	The maximum electricity demand customers place on the electricity network
Standard Control services	Essential Energy's core activities: providing access to, and supply of, electricity to customers
Prices/ Pricing	A cost charged to network customers to recover the efficient costs of providing network services. Commonly referred to as a 'tariff'
Pricing component	Different cost factors that work together to reflect the efficient costs of providing network services to customers, comprising network access, consumption and demand charges
Pricing schedule	The list of prices and pricing structures for each of our network charges, published annually. Also referred to as Network Price List and Explanatory Notes
Pricing structure	How pricing components are combined to give the pricing structure/network charge
Proposal	Essential Energy's April 30 2018 Regulatory Proposal for the 2019-24 regulatory control period submitted under clause 6.8 of the NER
Real	Dollars before the impact of inflation
Repex	Replacement capital expenditure
Residual	Those costs recovered annually that are above our Long Run Marginal Cost
Revised Proposal	Essential Energy's Revised Regulatory Proposal for the 2019-24 regulatory control period submitted under clause 6.8 of the NER.
Smart meter/interval meter	Digital device that measures and records each customer's electricity usage every half an hour and transmits the data to their electricity provider
Tariff	Network charge
ToU	Time of Use: a meter or charging parameter that varies according to whether electricity is consumed in the peak, shoulder or off-peak period
TSS	Tariff Structure Statement
TUoS	Transmission use of system. Charge for using the transmission network