

Attachment 6 – 2019-24 TSS

How we design our tariffs - Cost explanations and network charge design reasoning

April 2018



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1. Designing our proposed distribution charges under the National Electricity Rules

1.1 What do efficient charges look like?

The National Electricity Rules (NER) state that our network charges for each customer should reflect Essential Energy's efficient costs of providing these services to that customer. This means the network charge for each of our services must be based on the Long Run Marginal Cost (LRMC) of providing it to the retail customers assigned to that tariff. The LRMC is the cost to Essential Energy of servicing one more unit of demand or adding one more connection, including investment and associated ongoing maintenance costs.

Efficient charges preserve the LRMC while allocating costs that have already been incurred (residual costs) in a way that will provide minimal demand distortion. They signal to customers the future network cost of consuming the next unit of electricity.

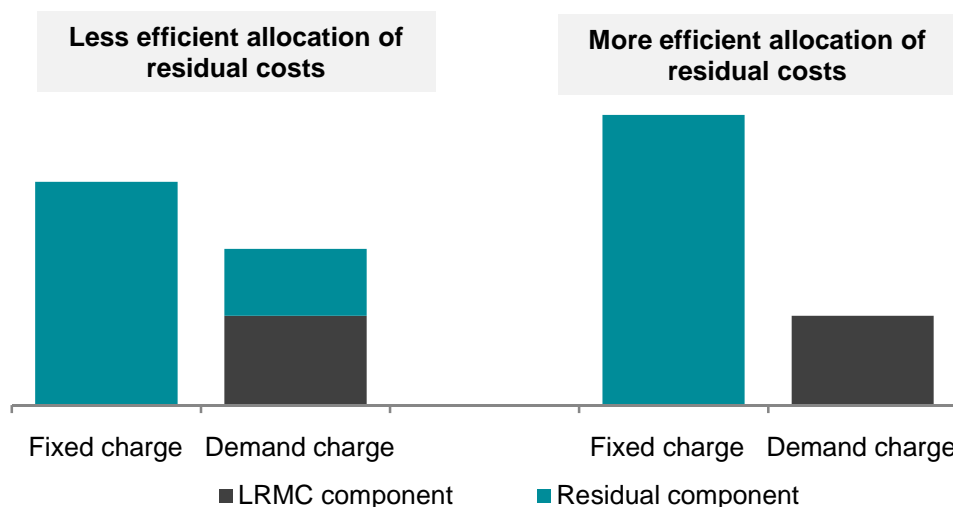
Where there are no network constraints, such as in off-peak times, this cost will be very low. However, if the network is reaching capacity at peak times, the cost to the network of consumers using more energy/demand at that time will grow until we need to augment the network to continue meeting demand. These additional costs should, under the NER, be reflected in the relevant variable usage component of the tariff.

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

- > A larger fixed component, to better reflect the costs of building and maintaining the current network.
- > Where possible (e.g. due to smart metering), a variable component linked to our marginal costs, reflecting the cost of future increases to the network from additional consumption.

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

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



1.2 Overview of network charging objective and principles

Clause 6.18.5(f) of the NER states that:

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

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

The charging principles must comply with the clauses in Table 1-1.

Table 1-1: NER Charging Principles

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

1.3 Efficient charging bounds

Revenue for each of our tariff classes lies between avoidable cost and stand-alone cost. This is important because:

- > Using only an LRMC calculation to set network charges would not allow us to recover all the network costs approved by the Australian Energy Regulator (AER).
- > Some residual costs are not recovered when our network charges are set to equal marginal cost.
- > The way we recover these residual costs has efficiency implications.

When recovering Essential Energy's residual costs, we must not charge inefficient levels of cross-subsidy or charge some customers less than the avoidable cost of not servicing them. Clause 6.18.5(e) of the NER limits the residual costs we can recover from any one tariff class by imposing an upper bound (the stand-alone cost) and a lower bound (the avoidable cost).

The **stand-alone cost** of serving a given group of customers in a tariff class is the total cost of servicing those customers if we rebuilt the network to meet their specific requirements, or met their equivalent energy reliability needs through a stand-alone energy solution. This upper bound ensures that customers in any given tariff class do not pay more because we are servicing other customers than if they sourced electricity directly.

Avoidable cost is the cost reduction resulting from any (potentially large) decrease in output associated with no longer servicing that same group of customers. This lower bound ensures that the revenue we recover from a given charging class exceeds the costs that could be avoided were the network not to supply these customers. The customer charge must be no lower than the costs we would avoid by not supplying them.

Stand-alone and avoidable cost are both important for determining how Essential Energy recovers residual costs associated with our network. Our method for estimating them remains the same as for our previous Tariff Structure Statement (TSS).

1.3.1 Method for estimating stand-alone and avoidable cost

We have used current expenditure as the basis for estimating stand-alone and avoidable cost. For example, to assess our stand-alone cost for the high voltage charging class, we have identified the existing assets and operating expenditure we would need for these customers.

Our framework uses two dimensions to classify each network cost category.

1. Whether costs are direct or indirect.

- > **Direct:** the cost can be attributed to a specific group of users and would not be incurred but for those users.
- > **Indirect:** the cost is common to multiple groups of users.

For example, a service line is directly attributable to an individual customer, but operational expenditure costs are generally indirect e.g. the cost of raising equity cannot be attributed to specific customers or customer groups.

2. Whether costs are scalable or non-scalable.

- > **Scalable: the cost tends to increase in proportion to the scale at which the service is provided.**
- > **Non-scalable: the cost is independent of the scale at which the service is provided.**

For example, maintenance and repair costs are scalable as they usually depend on the physical size of the network. Equity-raising costs will be independent of network characteristics such as the number of customers or maximum demand.

We calculate avoidable and stand-alone costs as follows:

- > **Avoidable cost** for each charging class is the sum of all direct costs multiplied by a weighting, which represents the proportion of direct costs that are attributable to that charging class.
- > **Stand-alone cost** for each charging class is the sum of avoidable costs, non-scalable indirect costs and scalable indirect costs multiplied by a set of scaling factors that vary according to the costs in question.

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

1.3.2 Comparison of revenue and charging bounds

Table 1-2 sets out our comparison of 2019-20 forecast revenue compared with our estimates of stand-alone and avoidable cost for each charging class. The results demonstrate that our proposed network charges satisfy the NER charging bounds.

Table 1-2: Proposed 2019-20 revenue (\$M) by charging class complies with the NER

Charging class	Avoidable (lower bound)	Stand-alone (upper bound)	Proposed	Proposed revenue lies between stand-alone and avoidable cost?
LV Residential and Small Business	321	2,208	713	Yes
Low Voltage Demand	87	695	201	Yes
High Voltage Demand	47	398	49	Yes
Subtransmission Demand (including IDTs)	6	56	14	Yes
Unmetered	3	26	9	Yes

1.3.3 Each network charge is based on LRMC

Under the NER, our network charges must be based on the LRMC, and ideally, this should comprise the variable component. Not all our network charges have been designed under the current rule framework, so we have accounted for LRMC differently in legacy and new network charges.

- > **Legacy network charges** that were designed before this obligation have been tested to ensure they will recover at least the relevant LRMC revenues attributable to customers on that network charge.
- > **New network charges** introduced in the previous TSS are based on the LRMC for the relevant variable charging parameters, regardless of whether it is demand or time of use (TOU) electricity.

Our methodology for estimating the LRMC was accepted by the AER in our previous TSS and has only changed for AER feedback, as explained in section 1.4.

Table 1-3 indicates our LRMC estimates by voltage level and our aggregated (delivered) LRMC estimate. These differ from our previous TSS as they have been updated for inflation. Aggregated LRMC includes the LRMC from higher voltages, so low voltage includes the LRMC of both high voltage and subtransmission as well as low voltage.

Table 1-3: LRMC estimates

Voltage level	LRMC Estimate (\$/kVA pa)	Aggregated LRMC (\$/kVA pa)
Subtransmission	13	13
High voltage	102	116
Low voltage	21	137

Table 1-4 sets out how our proposed network charges for the 2023-24 year (final year of this regulatory period) compare with our estimate of the LRMC. The LRMC has been translated to the specific charging component for comparison. However, our proposed charging components for demand-based charges still incorporate both consumption charges and demand charges, which need to be considered together in LRMC comparisons.

Table 1-4: LRMC comparison to proposed network charge components by charging type \$2018-19

Anytime (block) network charges

Code	Name	LRMC	Proposed 2023-24 DUOS	
		Charge c/kWh	NAC \$/year	Energy c/kWh
BLNN2AU	LV Residential Anytime	1.93	330.72	8.37
BLNN1AU	LV Business Anytime	1.93	330.72	12.05

Time of Use network charges

Code	Name	LRMC			Proposed 2023-24 DUOS			
		Peak c/kWh	Shoulder c/kWh	Off-peak c/kWh	NAC \$/year	Peak c/kWh	Shoulder c/kWh	Off-peak c/kWh
BLNT3AU	LV Residential TOU	6.26	2.94	0.22	330.72	11.39	8.78	2.69
BLNT2AU	LV Business TOU <100MWh	6.62	3.66	0.22	330.72	11.96	8.34	2.69
BLNT3AL	LV Residential TOU Interval	5.30	3.38	0.25	2413.11	12.22	9.05	4.42
BLNT2AL	LV Business TOU <100MWh Interval	8.83	2.82	0.25	562.06	12.49	8.71	4.17

Demand network charges

Code	Name	LRMC			Proposed 2023-24 DUOS						
		Demand charge \$/kVA/M			NAC \$/year	Energy charge c/kWh			Demand charge \$/kVA/M		
		Peak	Shoulder	Off-Peak		Peak	Shoulder	Off-peak	Peak	Shoulder	Off-Peak
BLND1AR	Small Residential-Opt-in Demand	3.46	3.25	0.46	330.72	0.93	0.49	0.27	4.11		0.00
BLND1AB	Small Business-Opt-in Demand	3.46	3.25	0.46	562.06	3.28	1.97	0.63	6.78		0.00
BLND3AO	LV TOU Demand 3 Rate	3.46	3.25	0.46	5813.40	0.87	0.65	0.19	10.51	9.35	2.32
BLNDTRS	Transitional Demand	3.46	3.25	0.46	5813.40	0.87	0.65	0.19	10.51	9.35	2.32
BHND3AO	HV TOU mthly Demand	3.48	3.20	0.57	7196.05	0.67	0.50	0.28	9.55	8.30	2.54
BSSD3AO	Sub Trans 3 rate Demand	0.66	0.32	0.02	7143.14	0.22	0.12	0.10	3.61	2.58	1.03

1.4 Estimating LRMC

1.4.1 Choice of LRMC method

In this TSS, Essential Energy has retained the average incremental cost approach for estimating the LRMC of our network services. The average incremental cost approach averages the total cost of supplying new growth in demand over that growth in demand by calculating the average change in projected operating and capital expenditure attributable to future increases in demand. This involves:

- > Projecting future operating and capital costs attributable to expected increases in demand,
- > Forecasting future load growth for the relevant network asset (or assets), and
- > Dividing the present value of projected costs by the present value of expected increases in demand.

We have used the average incremental cost method again for several reasons.

- > It relies on information that is currently available within our business from the 2019-24 network charge review process and our longer-term asset planning processes
- > It is less data-intensive than the alternative perturbation method, making it easier to apply and to explain during stakeholder engagement
- > It is a cost-effective approach
- > It has been adopted by all other distribution networks and approved by the AER during the first round of TSS reviews.

1.4.2 Addressing AER feedback on our previous TSS

The AER's final decision on our previous TSS provided feedback for our future LRMC estimation. It suggested we extend the time horizon for projected costs and demand and include replacement expenditure.

In response, we have extended the time horizon for our LRMC calculation method to 15 years and included relevant elements of our replacement expenditure forecasts.

1.4.3 Modelling LRMC

Our modelling estimates the LRMC by system voltage level i.e. subtransmission, high voltage, and low voltage.

The LRMC estimate includes three components:

- > Growth capital expenditure,
- > Incremental operating and maintenance costs, and

- > The component of replacement capital expenditure that is capacity-enhancing.

Growth capital expenditure, capacity-enhancing replacement capital expenditure and growth operating expenditure are all directly forecast to 2029. After that, we have estimated values based on demand growth and expenditure per unit of demand inputs.

Demand at each voltage level is forecast to 2029, then estimated based on population growth forecasts.

For growth capital expenditure and the component of replacement capital expenditure that is capacity-enhancing, 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. We have calculated a 15-year Net Present Value (NPV), and the LRMC is calculated as the discounted costs divided by the discounted change in demand at each voltage level.

Our modelling then transforms the LRMC estimate to network charge component values, considering both the probability that consumption on a particular network charge will occur at the time of the system peak and the quantum of the component that would be billed for a 1kVA demand.

Box 1.1 LRMC transformation examples using low voltage network charges

Anytime electricity charge
Peak period electricity charge
Controlled load charge
Demand charge

Assume the estimate of LRMC at low voltage is \$300/kVA, and (for simplicity) that all customers have a power factor of 1.0.

Anytime charge: In a year, a 1kVA constant demand on an anytime electricity network charge will use 1kVA x 1.0kW/kVA x 365 days per annum x 24 hours per day = 8760kWh. A 1kVA continuous demand will certainly be using energy at the peak time, because it operates all the time. Therefore, for the anytime electricity network charge, we transform the \$300/kVA LRMC into a component value as: $100\% * \$300/\text{kVA} / 8760 \text{ kWh/kVA} = \$0.034/\text{kWh} = 3.4\text{c/kWh}$.

Peak period charge: If the peak period is 10am to 10pm on summer days (Nov to Mar), there are 12 hours per day x 151 peak period days per annum = 1812 peak period hours per annum. An additional 1kVA of demand would use 1812kWh of peak period electricity. Again, it is virtually certain that the peak will occur during the time the network charge is valid. Therefore, for the peak period electricity charge, we transform the \$300/kVA LRMC into a component value as: $100\% * \$300/\text{kVA} / 1812 \text{ kWh/kVA} = \$0.166/\text{kWh} = 16.6\text{c/kWh}$.

Controlled Load charge: Assume a Controlled Load network charge provides 8 hours of supply (generally for water heating) at some time between 10pm and 7am every day. There are 8 hours per day x 365 days = 2920 hours of supply per annum. An additional 1kVA of demand would use 2920kWh of Controlled Load electricity. However, it is virtually certain that the charge will not be active at the time the peak occurs. Therefore, for the Controlled Load charge, we transform the \$300/kVA LRMC into a component value as: $0\% * \$300/\text{kVA} / 2920 \text{ kWh/kVA} = \$0.000/\text{kWh} = 0.0\text{c/kWh}$.

Monthly demand charge: The charging parameter is the highest demand in the month. An additional 1kVA demand would generate 1kVA each month or 12kVA-months per annum. There will be diversity between customers, so all customers do not peak at the same time or when the system peaks. Charging an anytime maximum demand without accounting for this diversity would over-recover the LRMC. Assume the inter-customer diversity is 60%. For the monthly demand charge, we transform the \$300/kVA LRMC into a component value as: $60\% * \$300/\text{kVA} / 12 \text{ kVA-months} = \15 per kVA-month .

1.5 Mapping cost concepts to charging parameters

When designing our network charges, we have aligned our cost types to relevant charging parameters and considered how these parameters will influence customers' electricity usage decisions.

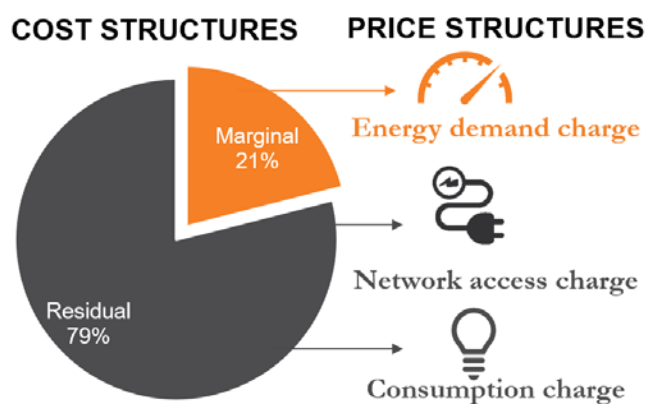


Figure 1-2: Aligning costs with charges parameters

Figure 1-2 shows the shares of our total building block costs that are attributable to growth-related (marginal costs) and to largely fixed (residual costs).

To comply with NER 6.18.5 (g) (1) to (3), we have used our marginal cost estimates when setting demand charges, because demand drives our marginal costs.

We have then recovered residual costs from our network access charges and consumption charges. This ensures we recover residual costs in ways that least distort customers' usage decisions.

We have also tested that the revenue from each non-demand-based network charge is greater than LRMC.

1.6 Network charges reflect efficient costs and minimise charging signal distortions

If we set charges based only on our LRMC estimates, we would not recover all our required revenue. The NER require us to consider how to recover the remaining costs (residual costs) in a way that minimises distortions to charging signals.

We have weighed the ability of our network charges to reflect efficient costs and minimise charging signal distortions against how easy they are for customers to understand, and the impact of any changes on customer bills. We have also considered other applicable regulatory instruments. The way we have balanced these requirements is discussed in more detail in Section 2.

Residual cost allocation

We have sought to allocate residual costs – the difference between LRMC-driven costs and our allowed revenues determined by the AER. Our approach minimises distortions to efficient charging signals and encourages opt-in uptake of our new cost-reflective demand charges.

This approach means our most efficient network charges (demand) most closely reflect their LRMC estimates, while our least efficient network charges (anytime) attract a greater share of residual costs. As shown in Figure 1-2, it also involves allocating more residual costs to access (fixed) and consumption (electricity) charges.

Figure 1-3 shows that, where the charging parameters are not closely linked to the drivers of Essential Energy's costs (i.e. where TOU KVA demand is not the key driver), they have been allocated a higher share of residual costs. This allocation across charges provides the least distortion to customers' efficient use decisions and supports opt-in uptake.

Figure 1-3: Allocation of residual costs between network charging types and customer types

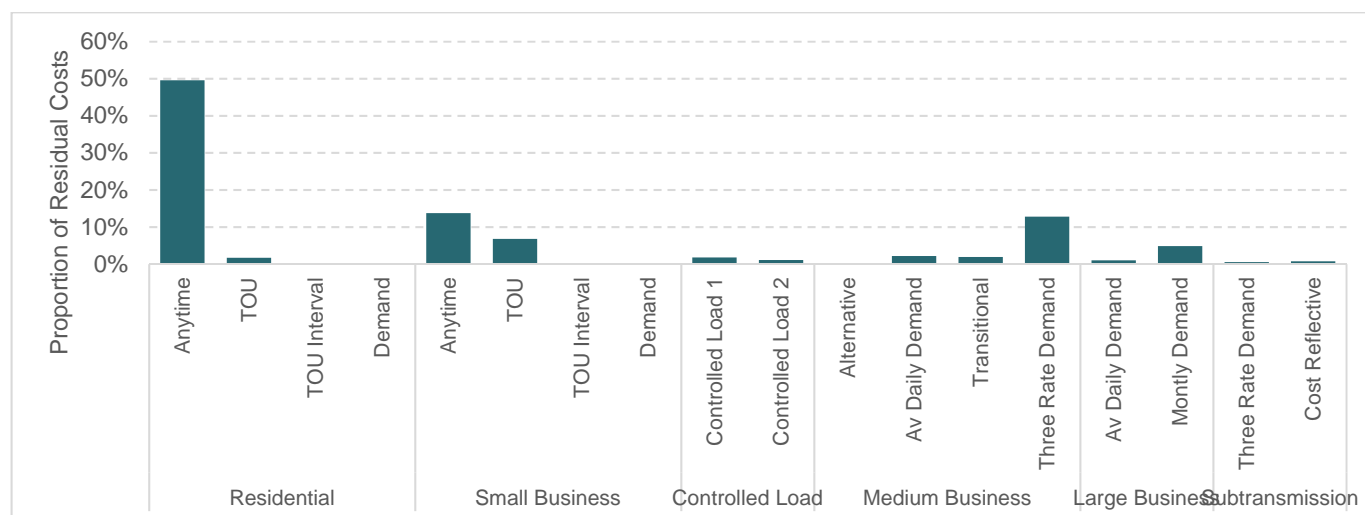


Figure 1-3 shows that we have continued this principled approach to allocations of residual costs within network charges based on the various charging parameters within each one. Charging parameters that are not closely linked to the drivers of Essential Energy's costs, such as fixed and usage charges, have been allocated a higher share of residual costs and the demand charge does not attract as much of the residual costs. This allocation again provides the least distortion to customers' efficient use decisions.

1.7 Treatment of pass-through costs

Our treatment of pass-through costs has not changed from our previous TSS.

Pass-through of jurisdictional scheme costs

When setting network charges, Essential Energy considers amounts for approved jurisdictional schemes and ensures these costs are passed on to customers. Additional requirements, such as only 25 per cent of the NSW Climate Change Fund being recovered from residential customers, are also adhered to. We make adjustments for under-recoveries or over-recoveries made in the previous year.

Pass-through of transmission costs

The AER allows us to recover our transmission-related costs. These are a significant cost component and are recovered as part of our total network charges.

Transmission-related payments are known as TUOS charges, and include:

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

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

We allocate transmission charges using several principles.

- > We allocate the total TUOS to network charges in alignment with our total expected transmission-related payments.
- > We align the pass-through of transmission charges and the structure of network charges wherever possible.
- > Our site-specific customers are allocated transmission charges in a way that preserves the location and time signals of transmission charging as per section 6 of the NER. These charges are passed through as closely as possible, reflecting how the charges are levied on Essential Energy.

- > We allocate transmission charges for all other customer classes (i.e. standard customers) on an average basis. This is due to the difficulties associated with equitably allocating the general and common service fixed charge as a fixed network access charge and passing through location charging signals that cannot be preserved when the end charge is applied to many customers within the network.

For Large Customers with site-specific charges, the individual cost of transmission is directly assigned to the customer. The balance is allocated to standard customer classes.

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

While allocating the large fixed charge component is reasonably discretionary, we have allocated it between customer classes based on consumption, which balances equity and efficiency. Only the peak and shoulder energy component can be readily passed on to customers through distribution charges.

Transmission charges are allocated on their non-TOU electricity, peak and shoulder consumption and/or demand. They are added to the distribution network charges for each customer class. The intention of this mapping methodology is to preserve the cost drivers inherent in the transmission charge within the customer's network charge, as far as possible.

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

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

2. Aligning our charging windows to our costs

2.1 Setting our charging windows

TOU charging windows that apply to consumption and demand charges are uniformly set to the same time windows for all current network charges. There are exceptions for some legacy or obsolete charges with meters we cannot cost-effectively reprogram.

We have developed these charging windows to provide accurate signals of network congestion and costs. For customers with interval or higher capability meters, they are:

- > **Peak period:** 5.00pm–8.00pm weekdays.
- > **Shoulder period:** 7.00am–5.00pm and 8.00pm–10.00pm weekdays.
- > **Off-peak period:** All other times.

For customers on certain obsolete charges with basic accumulation meters that cannot be reprogrammed (see section 2.1.2), the morning peak period is still from 7:00-9:00am.

Table 2-1: Tariffs that will still incur a morning peak charge

BLNT3AU – Residential TOU	BLNT1SU – LV TOU South
BLNT2AU – Small business TOU	BLND1CO – LV TOU Demand 1 Rate
BLNP3AO – LV Public Lighting	BLND1SR – LV 1 Rate Demand Sth Rural
BLNS1AO – LV TOU avg daily demand	BLND1SU – LV 1 Rate Demand Sth Urban
BHNS1AO – HV TOU avg daily demand	BHND1CO – HV 1 Rate Demand Cent Urban
	BHND1SO – HV 1 Rate Demand Sth Urban

To support cost-reflective charging, we use charging windows that signal times when the whole network is likely to experience high levels of demand. Charging windows must be:

- > Wide enough to capture peak demand periods,
- > Not so narrow that it is easy to shift demand by moving the network peak from one time period to another, and
- > Wide enough to ensure customers can respond to the charging signal and manage their bills by spreading their load over the period.

The AER decision on our previous TSS (and that of other DNSPs) encourages us to continue making refinements to our charging windows in future TSSs to more closely reflect times of network congestion. The AER sees scope for refining how we set charging windows and the charging windows themselves.

We have analysed our historical and forecast demand data to determine appropriate cost-reflective charging windows for our network circumstances and have taken into consideration three factors.

- > Actual network demand and the profile of network congestion over the day and across the year,
- > Cost versus benefit of any proposed changes, and
- > Stakeholder preferences.

2.1.1 Network demand and congestion

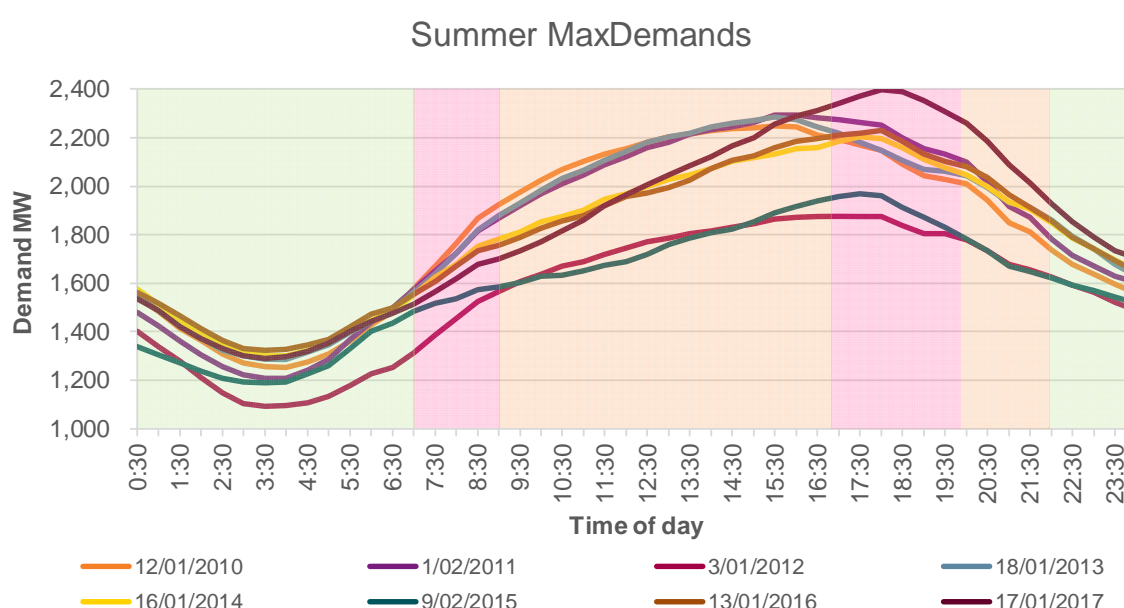
Network demand

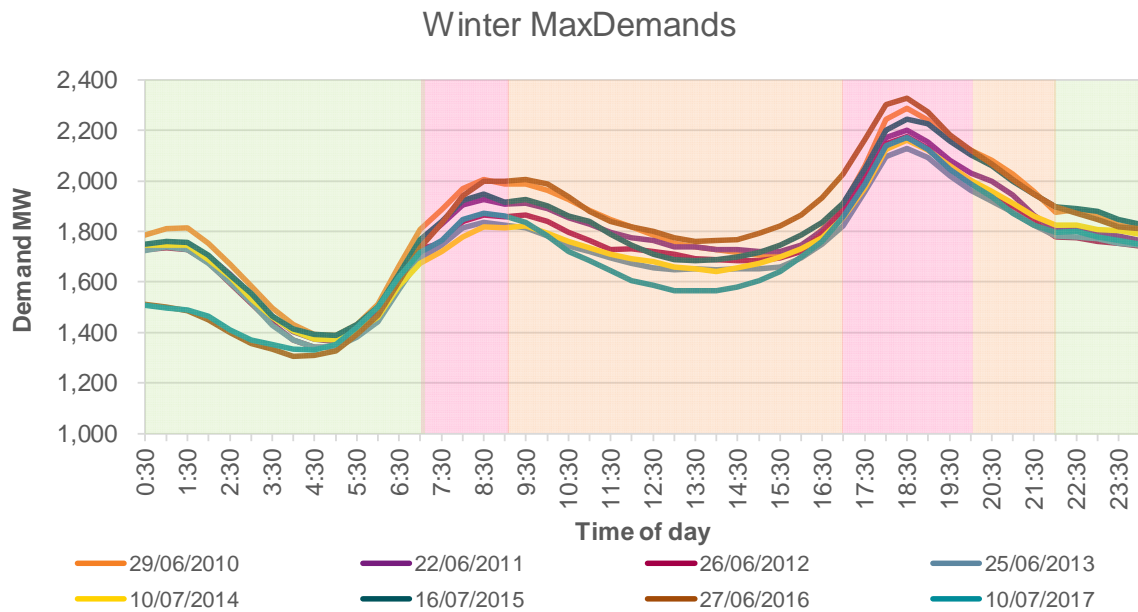
Analysing a range of data in Figure 2-1 provides a clear picture of network demand. Figure 2-1 compares the peak day network-wide demand for the last eight years (split between summer and winter) and peak day data for 2014-16 against our legacy charging windows.

It demonstrates that:

- > The evening peak and winter morning peak align with our legacy peak windows.
- > While the average winter evening peak had historically been higher than the summer peak, actual peak demand days are now showing a higher summer peak.
- > Although our winter morning peak is quite distinct, it is not as high as the evening peak and covers a wider period than the existing morning peak window.
- > The summer peak has moved to later in the evening as solar power reduces peak demand in the afternoon.
- > Morning demand in summer is not substantial but forms part of the gradual increase in demand during the day heading to the evening peak.
- > The winter evening peak window is narrower and slightly later than the summer equivalent.
- > There is sufficient evidence to support retaining our current peak charging window for all new network charges (5:00pm to 8:00pm).

Figure 2-1: Summer and winter peak days and average daily demand profile against legacy charging windows

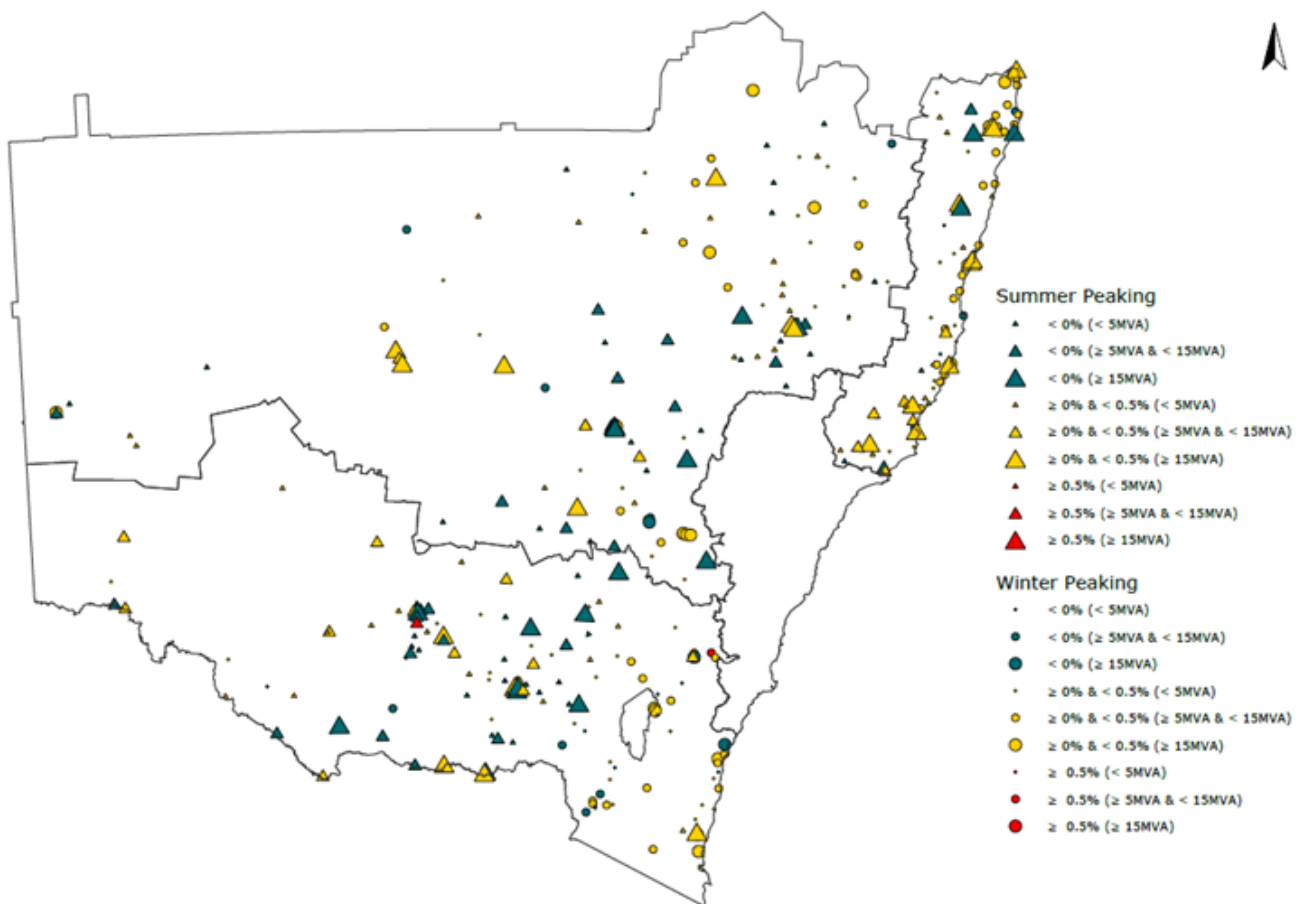




Localised network congestion

Network demand varies across areas within our network. Some areas exhibit common winter and summer peak periods, while others do not. Figure 2-2 highlights zone substation pressures across our network and demonstrates that some areas peak in winter, others peak in summer and some peak in both.

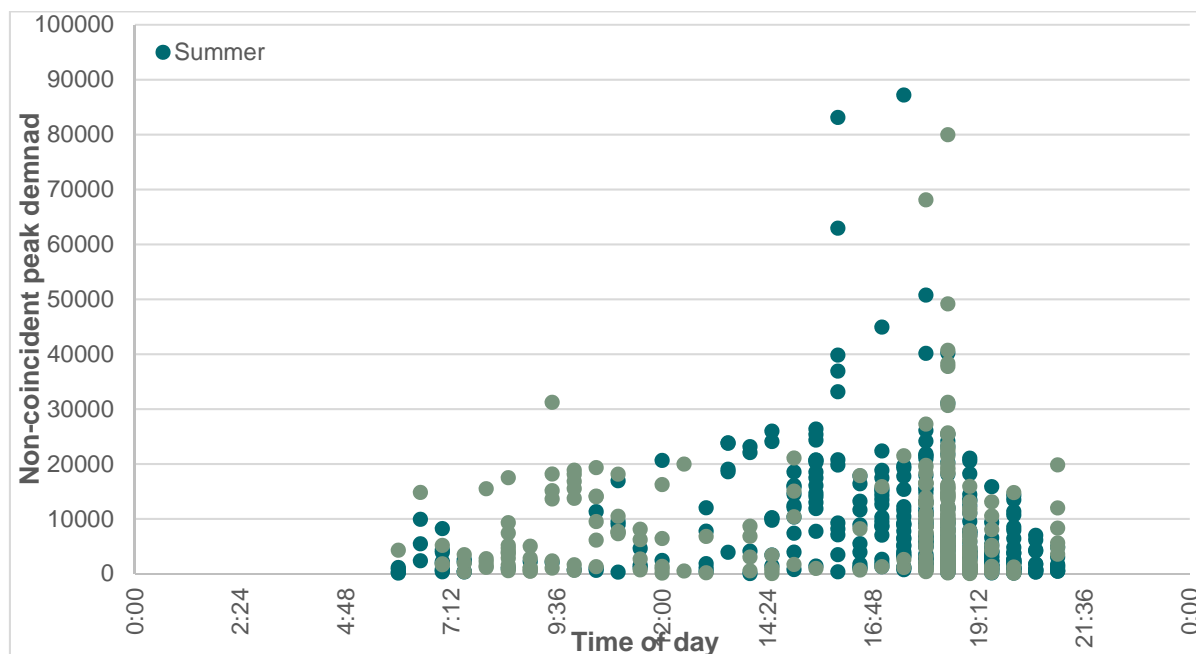
Figure 2-2: Zone substation peaks across our network



Although the network-wide demand profile is important when determining network congestion, so are zone substation demand profiles. These localised congestion outcomes drive our investment decisions.

Figure 2-3 shows that, although the peak demand period falls within the evening charging window for many zone substations, a significant number do not peak during that window. It also shows that peaks are spread across summer and winter.

Figure 2-3: Non-coincident peak demand by season and zone substation, 2016-17



Findings from network demand and congestion analysis

At a high level, this analysis suggests that recent congestion patterns on our network support two actions.

- > Removing the summer morning peak window and extending the shoulder window to cover it.
- > Not adopting seasonal charging, as winter and summer evening peaks are at a similar level but do differ across the network.

However, there is other evidence to consider.

- > The spread of peaks across the network when viewed at the zone substation level makes it difficult to determine the optimal windows for each season.
- > The windows for summer and winter are not that dissimilar.
- > Support for the existing 5pm to 8pm window being retained as a single evening peak window for both seasons.

2.1.2 Costs vs benefits of reprogramming meters

When preparing Essential Energy's previous TSS, we assessed the costs and benefits of reconfiguring legacy meters so we could change their charging windows, concluding that the benefits are unlikely to outweigh the costs. We still consider this to be the case.

It would be cost-prohibitive to reprogram obsolete meters to new charging windows, relative to the likely benefits. Also, if the peak window changed in the future, it would not be feasible to reprogram these meters each time.

We have approximately 280,400 basic accumulation meters with TOU capability and 528 Type 5 meters spread across our network area. They would all require reprogramming. In developing our previous TSS, we explored three reprogramming options and concluded they were not cost-effective, particularly given the commencement of metering contestability from December 2017.

Box 2.1 Meter reconfiguration options and cost estimates

Essential Energy does the work: If we assume each meter requires 30 minutes for upgrading (including travel time, meter reprogramming and updating the meter data and charging rate in the billing system), the associated direct cost would be at least \$67 per meter, based on our current approved field worker rates for our ancillary network services fees¹.

When this amount is multiplied by the estimated 302,000 applicable meters, this equates to over \$20 million. If a seasonal charging window were also applied to these meters, this cost would be incurred twice every year.

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

A contractor does the work: Essential Energy's meter-reading contractor has confirmed that its staff may not have the necessary accreditation to be able to reprogram a meter. Additionally, the contractor has optimised meter-reading rounds to ensure that staff are fully engaged.

Since reprogramming takes an estimated five minutes per meter, reprogramming 12 meters per day would add almost an hour of extra work. There is no capacity for meter upgrades to be undertaken during normal rounds. The cost of contracting additional external staff to undertake this work would be similar to the cost for Essential Energy staff to do it – between \$10 and \$20 million dollars per cycle change.

Use remote reprogramming: Our meter-reading contractor has investigated whether specially-designed software could be combined with each meter reader's smartphone and meter-reading probe to expedite reprogramming. The cost estimate for developing the software was at least \$1 million, as it needs to cover all the different meter brands, associated licence fees and development and testing time. When added to the extra costs of our staff developing a script for uploading the data into our billing systems, the total estimated cost was at least \$2 million.

2.1.3 Stakeholder feedback

When we engaged with stakeholders for our previous TSS, they supported charging windows that reflect network demand but generally did not support the work and costs involved in meter reprogramming. Regardless of whether the proposed project was stand-alone or carried out in conjunction with existing meter reads, it was seen as a waste of time and money given metering contestability.

Neither our customer research forums nor our Pricing Working Group supported applying seasonality to our network charges and charging windows. In the absence of more uniform regional demand patterns, we see seasonal charging windows as being similar to locational charges, a concept that was wholeheartedly rejected by stakeholders.

In our Pricing Working Group, we also tested the option of adopting an anytime changing window for demand charges. This was not supported. Instead, stakeholders favoured retaining current charging windows. These align with the charging windows for our TOU electricity charges, so they are easier for Essential Energy and retailers to explain, and for customers to understand.

2.1.4 Our proposed charging windows

We have weighed up the evidence and stakeholder feedback around changing our charging windows and have four proposals.

1. No change to the existing charging windows for TOU consumption charges associated with basic accumulation meters and Type 5 meters.
2. Retaining more cost-reflective charging windows for TOU consumption and demand charges associated with interval (or higher capability) meters, as approved in the prior TSS.

3. Retaining alignment of the charging windows for TOU consumption and demand charges to aid simplicity and customer understanding.
4. No seasonal windows for TOU consumption and demand charges.

Our proposed charging windows for different meter types are:

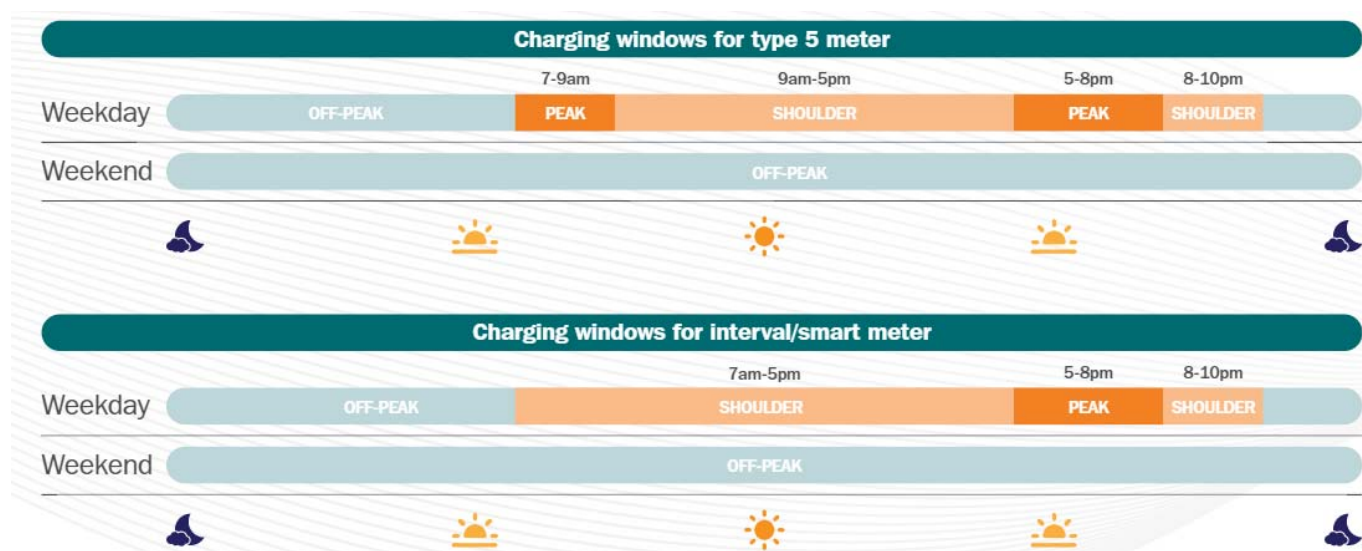
Peak When the network is experiencing high demand – weekdays 5.00 pm-8.00 pm

Shoulder When the network is experiencing moderate demand – weekdays 7.00 am-5.00 pm and 8.00 pm-10.00 pm

Off-peak When the network is experiencing little demand – weekdays 10.00pm-7.00am, and weekends. Customers with type 5 meters on Time of Use Will also have peak charges on weekday mornings 7.00 am – 9.00 am

These times are shown in Figure 2-4.

Figure 2-4: Our charging windows for charges with Type 5 meters and with interval (or higher capability) meters



3. Considering customer impacts

In structuring our network charges, we have aimed to:

- > Comply with the charging objective and principles in the NER (see section 1).
- > Ensure simplicity and transparency, and that our charging structures can be readily understood through testing charging components and windows in our customer engagement program.
- > Fairly allocate costs between customers based on their share of relevant network costs.
- > Maintain predictable and relatively stable prices over time.
- > Empower customers to make efficient electricity consumption and investment choices, including having charges that support efficient and equitable network transformation and ensure passive customers are not unduly subsidising active customers.
- > Provide charging messages to customers that allow them to make appropriate decisions that will drive the associated level of network expenditure required.

These goals reflect the requirements of the National Electricity Law (NEL) and the NER and our understanding of what customers want from their electricity distributor, as identified through our substantial engagement program.

While improving charging signals for efficient use of the network was a major driver in our previous TSS and this one, managing customers' bill impact as we transition to more cost-reflective charges has played a significant role. For this TSS, we have focused our customer impact efforts in a more granular manner to ensure we can continue to make the necessary advancements in cost-reflectivity and ready ourselves for network transformation. This also reflects AER feedback about how Essential Energy should consider future default charging assignments.

Our customer impact management has involved:

- > Considering the future for network transformation and its potential customer impacts.
- > Designing demand charges that are attractive to customers.
- > Measuring customer impacts.
- > Having opt-out arrangements for most default assignments – see section 5 of our TSS.
- > Allowing for customer-specific charges for large and bespoke customers.

3.1 Network transformation and potential customer impacts

In 2017, Energy Networks Australia (ENA), in conjunction with the CSIRO, released the Electricity Network Transformation Roadmap (the Roadmap) to assist network businesses such as ours with transforming in response to changing market conditions. The Roadmap supports the potential for Australia to pursue an objective of zero net emissions by 2050.

A relevant finding from the Roadmap (and the underpinning CSIRO research on the impact of less cost-reflective charging structures) was that this could impact our customers differently. The differences depend on the extent to which customers choose to actively invest in new energy technologies — specifically, distributed energy resources (DER) such as solar and batteries. The research looked at different-sized households, applying scenarios where they actively invested in DER and where they either did not or could not. Figure 3.1 shows the research findings and the potential inequity if this situation is not addressed through more cost-reflective network charges.

We discussed this research with our Pricing Working Group, and it was a relevant factor in their default charging assignment feedback for customers who seek to connect new DER investments to the Essential Energy network.

Figure 3-1: Bill impact in 2050: enacting CSIRO/ENA Roadmap vs not acting

	Counterfactual			The Roadmap		
	Active \$	Passive \$	The Gap \$	Active \$	Passive \$	The Gap \$
Working Couple 	\$1,346	\$1,811	\$465	\$1,123	\$1,422	\$299
Medium Family 	\$1,816	\$2,601	\$785	\$1,428	\$1,988	\$560
Large Family 	\$2,794	\$3,950	\$1,156	\$2,346	\$2,734	\$288
Single, Retired 	\$1,058	\$1,730	\$672	\$883	\$1,355	\$472

We are keen to see the savings that can be achieved for all customers by reducing expenditure on the network for active and passive customers, and agree that providing the correct charging signals will be a significant part of achieving this. However, we have accounted for customer and stakeholder views and will be implementing cost-reflective prices on a slow, steady transition path.

3.2 Designing our demand charges to consider customer impacts

We have designed our small customer network charges using the same elements that were approved in our previous TSS.

- > Opt-in for customers who meet our eligibility criteria but mandatory for new customers connecting new technologies, consistent with the preferences of our Pricing Working Group (see TSS section 5).
- > Fixed charge (c/day) and monthly maximum demand charge (c/kVA) components, with the monthly maximum demand charge allowing customers to manage their demand and bill impact over time rather than facing a ratcheting demand charge.
- > One peak window for demand charges that covers both peak and shoulder periods (7am to 10pm weekdays) and one off-peak window (every other time), aligned with the charging window times for other TOU charges to keep things simple and make it easier for customers and retailers to understand.
- > More residual cost allocation to non-demand charges, to make them attractive for opt-in customers (see section 1.6).
- > Customer impact testing for demand charges that are opt-in for the majority (see section 0).

We have not changed the design of our demand charges for large customers with three rate demand and TOU consumption components.

3.3 Customer bill impacts

We believe our proposed network charges strike an appropriate balance between improving price signals for efficient use of the network while considering the bill implications for customers.

Residential and Small Business customers

The differences in 2023-24 residential and small business customer NUOS bills under our proposed charges are shown in Figure 3-2.

Figure 3-2: Comparison of proposed 2023-24 residential and small business NUOS bills by charging type

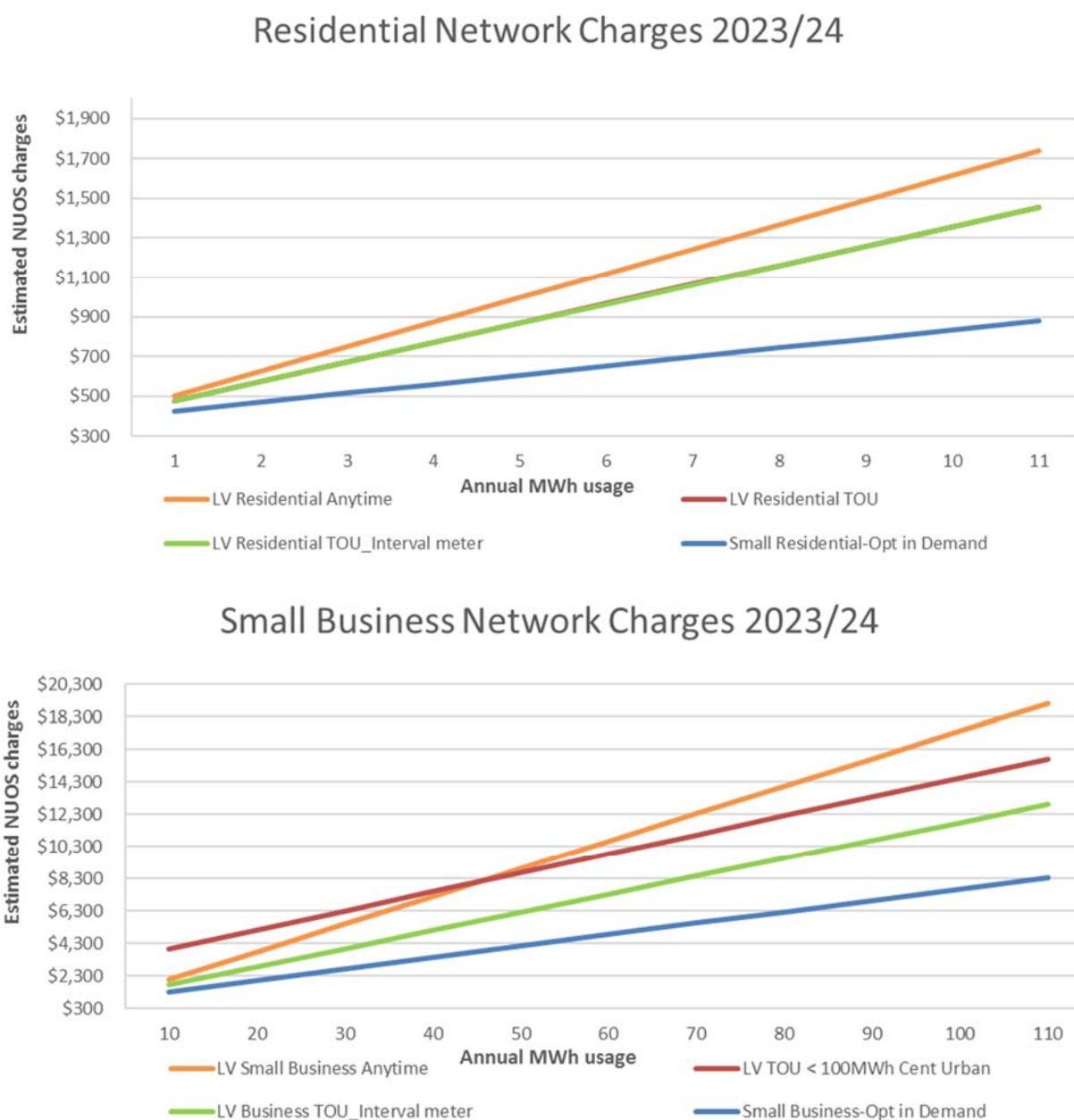


Figure 3-3 sets out our analysis of NUOS bill impacts by charging type for an average residential customer and two small business customers for the remainder of this regulatory period.

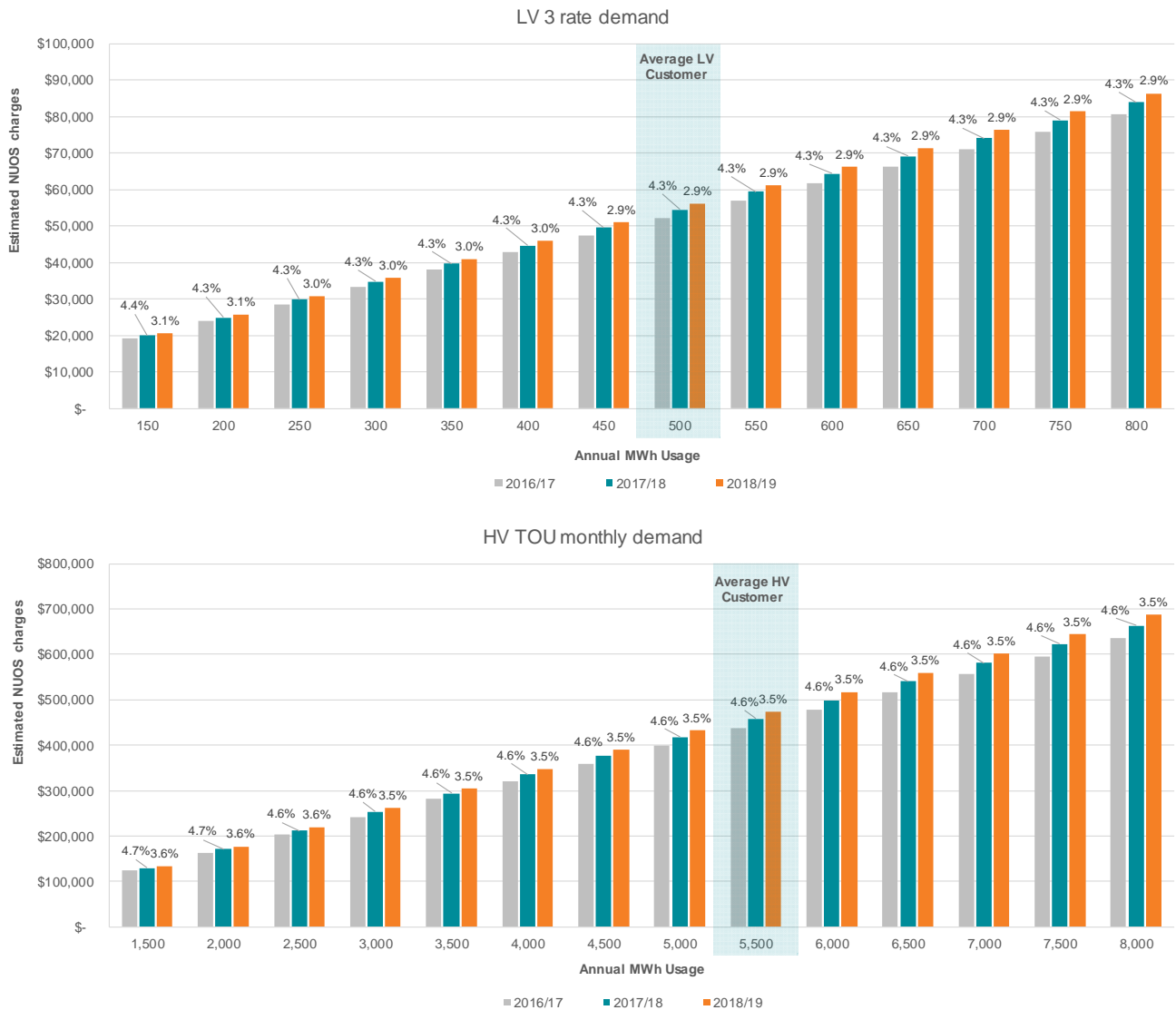
Figure 3-3: Average residential and small customer annual NUOS bill by charging type (with year on year change)

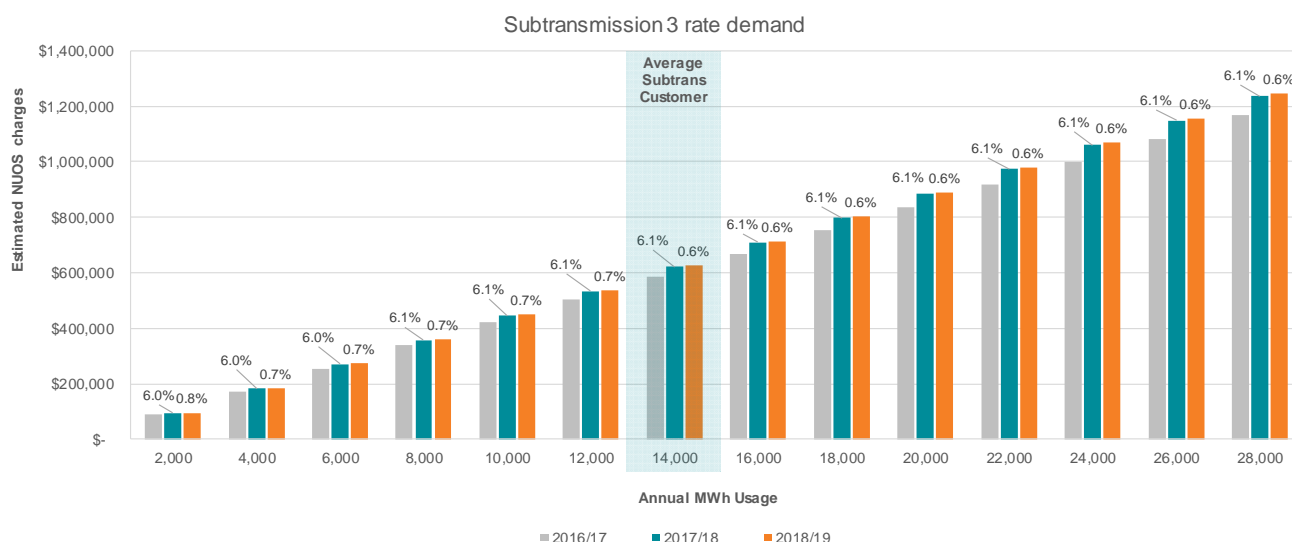


Business, Large Business and Subtransmission customers

Figure 3-4 shows only the major charges for these customer groups.

Figure 3-4: Business, large business and subtransmission annual NUOS bill (with year on year change)





We believe our proposed network charges are consistent with the NER charging principles as they provide improved charging signals for efficient use of the network and balance the bill impact of the proposed changes.

3.4 Customer-specific charges

For some large and unique customer connection requests, it can be most efficient for us to calculate a customer-specific network charge. Where the customer is sufficiently large to warrant the transaction costs of doing it, this allows us to consider and design a network charge that meets the charging principles at a more granular customer level.

We have adopted this approach in this TSS. Customers who meet our eligibility criteria for a customer-specific network charge will have a charging structure that includes:

- > A fixed daily access charge equivalent to other large users of similar size.
- > A peak demand charge aligned to our LRMC estimates.
- > TOU consumption charges set to recover an appropriate allocation of residual costs, having regard to current network use at the point where they seek connection and the cost of stand-alone alternative energy solutions.

This TSS period is likely to see growth in new customer electricity solutions, including large customers with their own large-scale distributed energy generation solutions and microgrid solutions. We consider that having the ability to calculate dedicated network charges will allow us to best meet the charging principles and support efficient and equitable network transformation.

3.5 Our compliance with the charging objective and principles

We have developed our network charges in accordance with the objective and principles set out in clause 6.18.5 of the NER. Table 3-1 outlines our compliance.

Table 3-1: How we have addressed the NER charging objective and principles

Charging objective	How we have addressed the objective
The network charge for direct control services for each of our customers should reflect the efficient costs of providing those services to those customers.	The variable component of our charges is at or above LRMC for each one. Residual costs are being allocated in a way that minimises impact on customer usage decisions and supports up take-up of opt-in demand charges.

	Charging principles	How we have addressed the principle
1.	Revenue to be recovered must lie between the stand-alone costs of serving customers and the avoidable costs of not serving those customers.	<p>This has been demonstrated in our LPMC model, available on request.</p> <p>In addition, each year our annual pricing proposal will demonstrate that the revenue we expect to recover from customers for each network charging class lies between the stand-alone costs of serving customers who belong to that class and the avoidable costs of not serving those customers.</p> <p>Our expected revenue for each class is estimated to lie between our estimates of stand-alone and avoidable cost.</p>
2.	Each network charge is to be based on LPMC.	<p>The variable component for each network charge is at or above LPMC.</p> <p>The approach that best suits our available inputs and network characteristics is the average incremental cost approach.</p>
3.	The revenue to be recovered from each network charge must reflect the total efficient costs of providing services to the customers assigned to that charge, in a manner that minimises distortions to use of the network.	<p>Our proposed charges align more closely to our estimates of the LPMC, taking into account customer bill impacts.</p> <p>Residual costs are being allocated in a way that minimises customer impact and improves revenue stability and makes efficient opt-in demand charges more attractive.</p>
4.	Consideration is to be given to the impact on customers of changes in network charges and the changes should be designed so they are reasonably capable of being understood by customers.	<p>Our proposed charging structures are largely unchanged from our current structures, so they can be easily understood by customers.</p> <p>The bulk of our customers are Residential and Small Business and will move to a simple flat rate charge. New connection and meter upgrade customers will be assigned to an appropriate TOU charge, with the option to move to a flat rate or demand-based charge. Customers connecting new technologies will be assigned to the applicable demand charge. We publish brochures to help customers better understand TOU, demand and controlled load charges.</p>
5	Charges must be readily understood.	<p>Our charging structures are simple to understand and most have been in place for some time. This makes them easy for customers to understand.</p> <p>Our new charges have either opt-in or opt-out assignment for most customers, supporting our ability to ensure customers understand them.</p> <p>We consulted with our Pricing Working Group to ensure our approach to measuring and charging for demand was understandable. As a result, we retained the current maximum demand in a given month approach, which is common across most networks. This was considered important as it enables retailers to provide customers with consistent messaging about demand charging. Demand averaging methods were considered potentially confusing, with more data points needing to be explained to users and a less direct relationship between peak use and bills.</p>
5.	Network charges must comply with any jurisdictional pricing obligations imposed by state or territory governments.	Our proposed charges take into account adjustments associated with the recovery of jurisdictional scheme costs – see section 1.7.

3.6 Future charging structures and directions

3.6.1 Changes to this TSS

A further means for us to manage customer impacts within the regulatory period is by amending our TSS. We can seek amendments to an existing approved TSS for events that occur beyond our reasonable control and that could not have reasonably been foreseen at the time of writing it. Such changes would be subject to consultation with our customers and stakeholders and would require AER approval.

3.6.2 Annual charging proposal

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

- > How we propose to vary charging levels from the start of the next financial year (1 July).
- > Any material differences between the charges proposed and the information on charges and charging structures in our TSS.
- > Reasons for any material differences between the proposal and the indicative charging schedule in our TSS.

3.7 Alternative control services

Our Alternative control services (Type 5 and 6 metering, public lighting and ancillary network services) are incurred by individual customers. Our approach to determining related charges is detailed in section 8 of our TSS.

4. How our charges interact with our demand management strategy

4.1 How demand management works

The network's capacity to supply load or absorb generation at any point can be constrained by the current rating of elements in the supply path or by unacceptable voltage conditions for customers. Traditional network solutions involve augmentation to increase the supply capacity by upgrading existing infrastructure or providing additional infrastructure to reduce the impedance of the supply path.

Demand Management (DM) and Non-Network Alternatives (NNA) offer substantial potential to achieve the power quality and capacity levels required of the electricity network at reduced costs compared to traditional network augmentation.

Essential Energy continues to refine the application of DM options and monitor emerging and innovative DM applications so we capture the benefits for our customers and stakeholders. This approach ensures we effectively use our resources and expenditure, with the aim of delivering a safe and reliable energy supply now and into the future.

The need to better manage demand led us to create a Controlled Load System for hot water storage systems. Converting to Controlled Load results in a net benefit to customers (through access to much lower off-peak charges) and Essential Energy (we control the load so we can cap network demand as required). Hot water storage units on Controlled Load are affordable for customers and are a much lower cost solution for us than augmenting the network.

During the current regulatory period, we have continued existing DM programs and developed new initiatives.

Existing programs

- > Ongoing optimisation of power electronic equipment control and field trials for electricity storage, reactive power and embedded generation. These solutions further enhance the cost-effectiveness of such technology in business-as-usual solutions and address network constraints. Continued development of this technology may lead to mutually beneficial outcomes for consumers and networks through increased penetration of renewables and mitigation of the resulting adverse effects on network power quality.
- > Evaluating conservation voltage reduction technologies that support reductions to customer consumption and peak demand.
- > Evaluating the use of mid-sized static synchronous compensators in power factor correction. This is a relatively simple alternative to traditional network augmentation but with major improvements to power quality over existing power factor correction technologies.
- > Developing optimisation techniques for existing and future field-based power factor correction, to ensure Essential Energy maximises the value of network equipment, now and in the future.

New developments

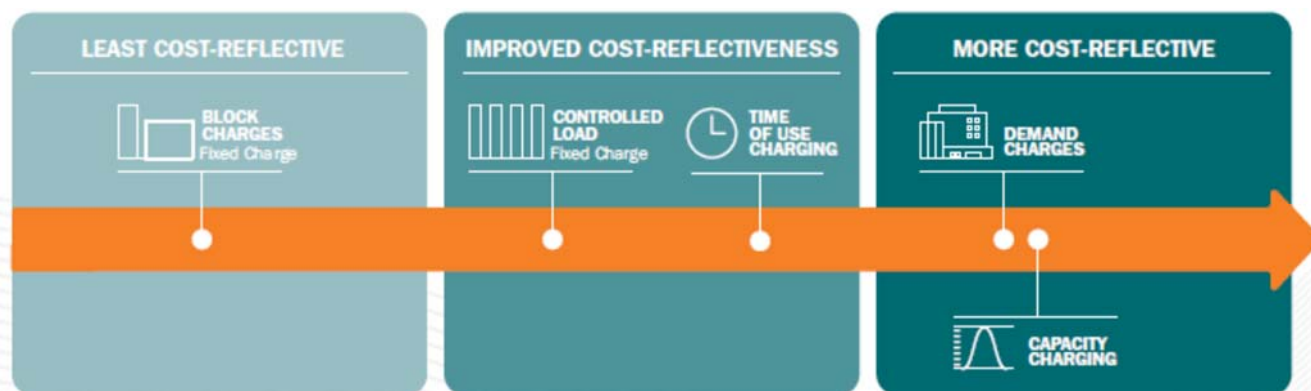
- > Mapping constraint and growth, to promote non-network proposals from a variety of interested parties.
- > Creating standards, guidelines and specifications for field-based switched capacitors, to help us source and guide the application of this cost-effective technology for business-as-usual DM applications.
- > Responding to the growing interest in battery storage technology behind the meter by trialling connection standards, metering and charges. Our aim is to guide the uptake of battery storage while ensuring it does not negatively impact the network and require costly expenditure. In addition, we are currently exploring the possible value battery storage technology can provide through deferring or avoiding network expenditure and the appropriate signals that would yield this potential.
- > Exploring least-cost options. Due to the varying customer density of Essential Energy's network across diverse terrain, some areas have a high cost-to-serve because there are very few customers, causing cross-subsidisation of network charges. These parts of the network (typically on the network fringes) are potential viable areas for transferring customers to an off-grid solution and decommissioning network assets. Essential Energy is exploring the practicality of implementing such least-cost solutions, using network investment in these areas as a trigger. This would minimise network costs, which is in the long-term interest of all customers.

- > Initiating load control system optimisation studies for problematic areas of the network, to further improve the cost-effectiveness of the load control system and identify least-cost alternative load control technology, as compared to traditional load control equipment.

4.2 Interaction with our charging strategy

Demand management is closely linked to charging structures that provide clear price signals that allow customers to make choices (price versus convenience) about when to use electricity. Figure 4-1 shows how different charging structures align with customer price signals.

Figure 4-1: Charging complexity and price signals for customers



In terms of Essential Energy's current charges:

- > The bulk of our customers are residential and small business customers. They are currently on highly volumetric charges (block charges). These are simple to understand, but not cost-reflective against an LRMC methodology. They send no price signal to customers.
- > We offer Energy Saver (formerly Controlled Load) charges to our residential and small business customers. Energy Saver charges allow us to control the use of certain household appliances, which are only operated at off-peak times, and customers pay lower rates. These charges are a trade-off between complexity and cost-reflectivity and send a clearer price signal than highly volumetric charges.
- > Our TOU charges are also in the middle ground — they are fairly simple to understand and send a clearer price signal to customers as they are somewhat cost-reflective.
- > Demand-based charges are our most cost-reflective. They send the most efficient price signal as customer use is highly correlated with network demand pressures. They are far more complex for customers to understand and appropriate technology is required if we want customers to adequately react to price signals.

We propose to change our residential and small business charges assignment policy. New connections with solar PV installations, battery storage or electric vehicles will be automatically assigned to the relevant demand charge, further improving the take-up of our more cost-reflective charges while sending clearer price signals to customers (see section 5 of our TSS).

Changes that we have already introduced to our charging windows (see section 2) will also enhance our ability to control network demand by better signalling to customers the network costs created by their demand pressure. Customers must have the appropriate meter technology.

5. Compliance checklist

The table below shows where in the TSS we have addressed each NER requirement.

Rule	Requirement	Addressed in
6.8.2 (a)	A Distribution Network Service Provider must, whenever required to do so under paragraph (b), submit to the AER a regulatory proposal and a proposed tariff structure statement related to the distribution services provided by means of, or in connection with, the Distribution Network Service Provider's distribution system.	TSS document, overview and attachments
6.8.2 (b) (1) to (2)	A regulatory proposal and a proposed tariff structure statement must be submitted (1) At least 17 months before the expiry of a distribution determination that applies to the <i>Distribution Network Service Provider</i> ; or (2) If no distribution determination applies to the <i>Distribution Network Service Provider</i> , within three months after being required to do so by the AER.	Submission to be made on 30 April 2018 per letter to Essential Energy from AER dated 3 October 2017, available on AER website
6.8.2 (c) (7)	A regulatory proposal must include (but need not be limited to) the following elements: A description (with supporting materials) of how the proposed tariff structure statement complies with the pricing principles for direct control services including: A description of where there has been any departure from the pricing principles set out in paragraphs 6.18.5 (e) to (g); and An explanation of how that departure complies with clause 6.18.5(c).	Section 7 - <i>Our pricing proposals methodology</i> of the TSS document Section 3 <i>Setting proposed tariffs that considering customer impacts</i> of this document.
6.8.2 (c1a)	The overview paper must also include a description of how the Distribution Network Service Provider has engaged with retail customers and retailers in developing the proposed tariff structure statement and has sought to address any relevant concerns identified as a result of that engagement.	Overview of this TSS
6.8.2 (d1)	The proposed tariff structure statement must be accompanied by an indicative pricing schedule.	Attachment 1 – <i>Indicative NUOS Pricing Schedule of this TSS</i>
6.8.2 (d2)	The proposed tariff structure statement must comply with the pricing principles for direct control services.	The entire TSS document and Attachments
6.8.2 (e) and (f)	If more than one distribution system is owned, controlled or operated by a Distribution Network Service Provider, then, unless the AER otherwise determines, a separate regulatory proposal and a separate tariff structure statement are to be submitted for each distribution system. If, at the commencement of this Section, different parts of the same distribution system were separately regulated, then, unless the AER otherwise determines, a separate regulatory proposal and a separate tariff structure statement are to be submitted for each part as if it were a separate distribution system.	Not applicable
6.18.1A (a)	A tariff structure statement of a Distribution Network Service Provider must include the following elements:	Section 3 - <i>Our customer classes</i> of the TSS document
6.18.1A (a)(1)	(1) The tariff classes into which retail customers for direct control services will be divided during the relevant regulatory control period;	
6.18.1A (a)(2)	(2) The policies and procedures the Distribution Network Service Provider will apply for assigning retail customers to tariffs or reassigning retail customers from one tariff to another (including any applicable restrictions);	Section 5 – <i>Assigning customers to customer classes</i> of the TSS document Attachment 5 – <i>Assigning customers to tariffs - Policies and procedures for assignment and reassignment of tariffs</i>
6.18.1A (a)(3)	(3) The structures for each proposed tariff;	

Rule	Requirement	Addressed in
6.18.1A (a)(4)	(4) The charging parameters for each proposed tariff; and	Section 6 - <i>Our proposed network charge structures</i> of the TSS document
6.18.1A (a)(5)	A description of the approach that the Distribution Network Service Provider will take in setting each tariff in each pricing proposal of the Distribution Network Service Provider during the relevant regulatory control period in accordance with clause 6.18.5.	Section 3 – <i>Considering customer impacts</i> of this document
6.18.1A (b)	A tariff structure statement must comply with the pricing principles for direct control services.	Section 7 - <i>Our pricing proposals methodology</i> of the TSS document, and this document
6.18.1A (e)	A tariff structure statement must be accompanied by an indicative pricing schedule which sets out, for each tariff for each regulatory year of the regulatory control period, the indicative price levels determined in accordance with the tariff structure statement.	Attachment 1 – <i>Indicative NUOS pricing schedule of this TSS</i>
6.18.3 (b)	Each customer for direct control services must be a member of one or more tariff classes.	Section 4 - <i>Our customer classes</i> of the TSS document
6.18.3 (c)	Separate tariff classes must be constituted for retail customers to whom standard control services are supplied and retail customers to whom alternative control services are supplied (but a customer for both standard control services and alternative control services may be a member of 2 or more tariff classes).	Section 4 - <i>Our customer classes</i> and Section 8 - <i>Proposed user pays charges</i> of the TSS document
6.18.3 (d) (1) to (2)	A tariff class must be constituted with regard to: (1) The need to group retail customers together on an economically efficient basis; and (2) The need to avoid unnecessary transaction costs.	Section 4 - <i>Our customer classes</i> of the TSS document
6.18.4 (a)	In formulating provisions of a distribution determination governing the assignment of retail customers to tariff classes or the 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.	Section 4 - <i>Our customer classes</i> of the TSS document Attachment 5 – <i>Assigning customers to tariffs - Policies and procedures for assignment and reassignment of tariffs</i>
6.18.4 (b)	If the charging parameters for a particular tariff result in a basis of charge that varies according to the usage or load profile of the customer, a distribution determination must contain provisions for an effective system of assessment and review of the basis on which a customer is charged.	Section 7 – <i>Our pricing proposals methodology</i> of the TSS document Section 1 – <i>Designing our proposed charges under the NER</i> of this document
6.18.5 (a)	The network pricing objective is that the tariffs that a Distribution Network Service Provider charges in respect of its provision of direct control services to a retail customer should reflect the Distribution Network Service Provider's efficient costs of providing those services to the retail customer.	Section 1 – <i>Designing our proposed network charges under the NER</i> of this document

Rule	Requirement	Addressed in
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).	Section 7 - <i>Our pricing proposals methodology</i> of the TSS document
6.18.5 (c) (1) to (2)	A Distribution Network Service Provider's tariffs may vary from tariffs which would result from complying with the pricing principles set out in paragraphs (e) to (g) only: (1) To the extent permitted under paragraph (h); and (2) To the extent necessary to give effect to the pricing principles set out in paragraphs (i) to (j).	
6.18.5 (d)	A Distribution Network Service Provider must comply with paragraph (b) in a manner that will contribute to the achievement of the network pricing objective.	
6.18.5 (e) (1) to (2)	For each tariff class, the revenue expected to be recovered must lie on or between: (1) An upper bound representing the stand-alone cost of serving the retail customers who belong to that class; and (2) A lower bound representing the avoidable cost of not serving those retail customers.	
6.18.5 (f) (1) to (3)	Each tariff must be based on the long run marginal cost of providing the service to which it relates to the retail customers assigned to that tariff with the method of calculating such cost and the manner in which that method is applied to be determined having regard to: (1) The costs and benefits associated with calculating, implementing and applying that method as proposed; (2) The additional costs likely to be associated with meeting demand from retail customers that are assigned to that tariff at times of greatest utilisation of the relevant part of the distribution network; and (3) The location of retail customers that are assigned to that tariff and the extent to which costs vary between different locations in the distribution network	
6.18.5 (g) (1) to (3)	The revenue expected to be recovered from each tariff must: (1) Reflect the Distribution Network Service Provider's total efficient costs of serving the retail customers that are assigned to that tariff; (2) When summed with the revenue expected to be received from all other tariffs, permit the Distribution Network Service Provider to recover the expected revenue for the relevant services in accordance with the applicable distribution determination for the Distribution Network Service Provider; and (3) Comply with 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).	
6.18.5 (h) (1) to (3)	A Distribution Network Service Provider must consider the impact on retail customers of changes in tariffs from the previous regulatory year and may vary tariffs from those that comply with paragraphs (e) to (g) to the extent the Distribution Network Service Provider considers reasonably necessary having regard to: (1) The desirability for tariffs to comply with the pricing principles referred to in paragraphs (f) and (g), albeit after a reasonable period of transition (which may extend over more than one regulatory control period); (2) The extent to which retail customers can choose the tariff to which they are assigned; and (3) The extent to which retail customers are able to mitigate the impact of changes in tariffs through their usage decisions.	Section 7 - <i>Our pricing proposals methodology</i> of the TSS document Section 3 – <i>Considering customer impacts</i> of this document
6.18.5 (i) (1) to (2)	The structure of each tariff must be reasonably capable of being understood by retail customers that are assigned to that tariff, having regard to: (1) The type and nature of those retail customers; and (2) The information provided to, and the consultation undertaken with, those retail customers.	Section 3 – <i>Considering customer impacts</i> of this document Section 7.1.5 - <i>Our network charge structures can be easily understood</i> of the TSS document

Rule	Requirement	Addressed in
6.18.5 (j)	A tariff must comply with the Rules and all applicable regulatory instruments.	Section 7 – <i>Our pricing proposals methodology</i> of the TSS document Section 1 – <i>Designing our proposed tariffs under the Rules</i> of this document
6.18.6 (a)	This clause applies only to tariff classes related to the provision of standard control services.	Annual Pricing Proposals
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.	
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 $(1 + \text{CPI})(1 - X)(1 + 2\%)$ (2) CPI plus 2%. Note: The calculation is of the form $(1 + \text{CPI})(1 + 2\%)$	Annual Pricing Proposals
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.	Section 1 <i>Designing our proposed network charges under the NER</i> of this document
6.18.7 (b)	The amount to be passed on to retail customers for a particular regulatory year must not exceed the estimated amount of the designated pricing proposal charges adjusted for over or under recovery in accordance with paragraph (c).	Attachment 1 – <i>Indicative NUOS Pricing Schedule</i> of this TSS
6.18.7 (c) (1) to (3)	The over and under recovery amount must be calculated in a way that: (1) Subject to subparagraphs (2) and (3) below, is consistent with the method determined by the AER in the relevant distribution determination for the Distribution Network Service Provider; (2) Ensures a Distribution Network Service Provider is able to recover from retail customers no more and no less than the designated pricing proposal charges it incurs; and (3) Adjusts for an appropriate cost of capital that is consistent with the allowed rate of return used in the relevant distribution determination for the relevant regulatory year.	Attachment 1 – <i>Indicative NUOS Pricing Schedule</i> of this TSS
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.	

Rule	Requirement	Addressed in
6.18.7A (a)	A pricing proposal must provide for tariffs designed to pass on to customers a Distribution Network Service Provider's jurisdictional scheme amounts for approved jurisdictional schemes.	Section 1.7 - <i>Treatment of pass-through costs</i> of this document
6.18.7A (b)	The amount to be passed on to customers for a particular regulatory year must not exceed the estimated amount of jurisdictional scheme amounts for a Distribution Network Service Provider's approved jurisdictional schemes adjusted for over or under recovery in accordance with paragraph (c).	
6.18.7A (c) (1) to (3)	The over and under recovery amount must be calculated in a way that: (1) Subject to subparagraphs (2) and (3) below, is consistent with the method determined by the AER for jurisdictional scheme amounts in the relevant distribution determination for the Distribution Network Service Provider, or where no such method has been determined, with the method determined by the AER in the relevant distribution determination in respect of designated pricing proposal charges; (2) Ensures a Distribution Network Service Provider is able to recover from customers no more and no less than the jurisdictional scheme amounts it incurs; and (3) Adjusts for an appropriate cost of capital that is consistent with the allowed rate of return used in the relevant distribution determination for the relevant regulatory year.	
6.18.7A (d) (1) to (2)	A scheme is a jurisdictional scheme if: (1) The scheme is specified in paragraph (e); or (2) The AER has determined under clause paragraph (l) that the scheme is a jurisdictional scheme, and The AER has not determined under paragraph (u) that the scheme has ceased to be a jurisdictional scheme.	
6.18.7A (e) (1) to (3)	For the purposes of paragraph (d)(1), the following schemes are jurisdictional schemes: (1) Schemes established under the following laws of participating jurisdictions: (i) Electricity Feed-in (Renewable Energy Premium) Act 2008 (ACT); (ii) Division 3AB of the Electricity Act 1996 (SA); (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.	

GLOSSARY

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