Tariff Structure Explanatory Statement
1 July 2019 – 30 June 2024

Endeavour Energy

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Executive Summary

What is the Tariff Structure Statement?

The Tariff Structure Statement (TSS) explains our proposed tariff structures for the 2019/20 to 2023/24 period. The National Electricity Rules (the Rules) set out a range of formal obligations and considerations that must be contained in the TSS.

The objectives of these requirements have simple and common sense concepts behind them and to achieve these objectives we seek to set prices on the basis of the following principles developed in conjunction with our customer representatives:

- **Fairness**: Tariffs are reflective of consumers' network costs;
- **Empowerment**: Consumers are empowered to make efficient consumption choices;
- **Transparency:** Ensure tariffs are simple and transparent; and
- **Predictability:** Prices are predictable and stable over time.

Why is Endeavour Energy changing its tariff structures?

The way in which customers use Endeavour Energy's distribution network has been changing and will continue to change at an increasingly rapid pace, driven by customer investments in smarter more energy efficient appliances and new technologies such as solar photovoltaic (PV) installations, batteries and electric vehicles.

At a very high level, these changes are primarily affecting the volume of energy being delivered via Endeavour Energy's network to customers, rather than their maximum demand for energy from the network. Importantly, it is customer's maximum demand that drives our network costs. However, our previous approach to pricing for residential and small business customers was based on volumetric energy based measures of network use. The disconnection between the network costs caused by a customer using the network, and the amount that customer pays, will lead to inefficient use of the network and inequitable outcomes for all our customers.

In this context, it is of the utmost importance that our tariffs also evolve to provide customers with the information they require to make informed and efficient decisions about their use of Endeavour Energy's network, and investments in new technologies.

Enabling customers to make appropriate decisions about network use and investments in alternative technologies like solar PV will assist Endeavour Energy to make future network investments that customers are willing to pay for and, ultimately, to provide the network services customers want to use at the lowest possible cost. The principal means by which tariffs promote this outcome is by signaling to customers the additional network costs resulting from further use of the network, which:

- encourages customers to use our network where the benefit they derive exceeds the cost of providing the relevant network service; and
- assists in identifying potential future network expenditure that is valued by customers.

More fundamentally, our changes to tariff structures have been designed to make energy more affordable to customers over the medium to long term by:

- creating greater opportunities for customers to lower their bill simply by changing the timing of consumption; and
- encouraging investments in technologies such as energy storage, west-facing solar PV and other technologies to reduce peak demand.

Further to the changes implemented in its first TSS, over the next regulatory control period Endeavour Energy is proposing:

- to improve its estimation of the future network cost consequences of further use of its network;

- to further refine the period over which it signals those costs to customers;
- to send a demand-based peak price signal to residential and small business customers; and
- to assign more customers to cost reflective tariffs.

What did our customers tell us?

Since the benefits of network tariff reform flow primarily from changes in the consumption choices of customers, it is imperative that our tariffs reflect the preferences of our customers. It is for this reason that customer and stakeholder feedback played a central role in the development of our proposed reforms.

The extension granted by the AER to consult further with customers was particularly important since it afforded Endeavour Energy the opportunity to gain important insights into the tariff structures that best reflect stakeholder preferences. By way of example, stakeholders indicated a strong preference for:

- a default demand tariff for residential and small business customers;
- demand tariffs that are as simple as possible; and
- a fully cost reflective opt-in demand tariff for customers willing to lead the way to cost reflective tariffs.

In response, Endeavour Energy prioritised the analyses required to take action on customers' feedback and, as a result, made fundamental changes to proposed tariff structures.

Endeavour Energy is proposing to make two important changes to its tariff structures, consistent with its aims of improving outcomes for all network users, namely:

- introducing two residential and two small business demand based tariffs to provide a clearer and simpler signal to customers about the costs imposed from using the network during peak periods; and
- realigning the demand charging window to more closely align the peak period to the times at which network usage peaks arise.

The introduction of demand tariffs for residential and small business customers

Our demand based tariffs will consist of three tariff parameters: a seasonal maximum monthly demand charge, a flat energy charge and a fixed charge.

The principal merits of Endeavour Energy's proposed demand tariffs are:

- **Empowerment** - they more effectively signal to customers the network costs that arise from further use of the network at peak times, which provide customers with the information they require to make decisions about network use and investments in new technologies that best meet their needs at least cost;
- **Fairness** - promotes the equitable treatment of adopters and non-adopters of new technologies like solar PV and batteries since it encourages investments that reduce our network costs (peak demand), rather than energy consumption, which benefits adopters and non-adopters;
- **Transparency** – they are straight forward to understand and include no more than three charging parameters; and
- **Predictability** – customers pay a network bill that better reflects the costs of their use of the network, which assists them in making long term network use and investment decisions.

To assist in managing the transition to demand based tariffs for residential customers, Endeavour Energy is proposing to introduce both a transitional demand tariff and a ''cost reflective' demand tariff to provide flexibility for customers to select the pace of their transition.

The transitional demand tariff will become the default tariff for all new customers and those existing customers with the required metering who upgrade their network connection to three-phase or the bi-directional flow of electricity. Customers assigned to the transitional demand tariff will have the option to opt-out to the flat energy based tariff or the seasonal time of use tariff.

The cost reflective demand based tariff will be available to all customers on an opt-in basis subject to metering requirements.

Refining charging windows

The definition of our charging windows is a key element of Endeavour Energy's tariff strategy. This is primarily because the definition of the peak period determines the times of the day at which it signals long run marginal cost (LRMC) to customers.

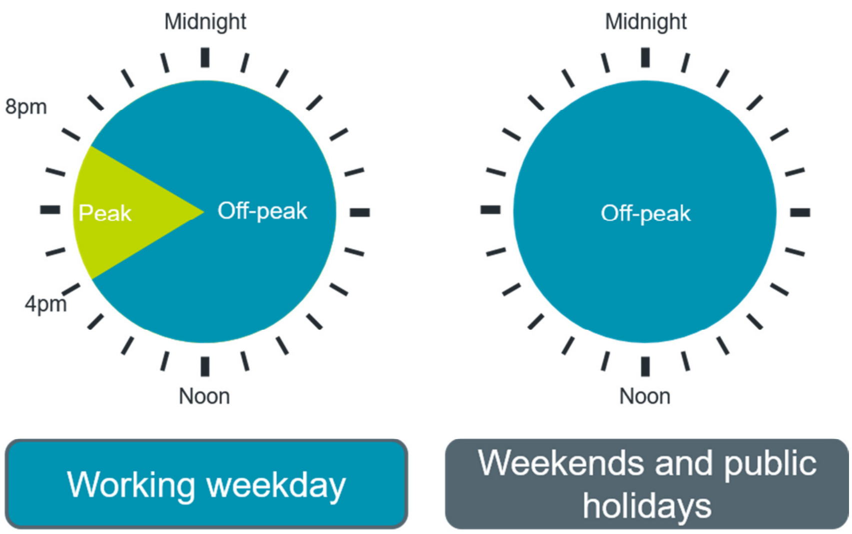
The importance of our charging windows is reflected in the in-depth analysis of peak demand events presented in Chapter 7.

This analysis evaluated the timing of peak demand events:

- at the network level;
- in each of the regions that comprise our network; and
- at the assets and locations where demand is driving our forward-looking costs.

Endeavour Energy proposes to narrow the existing peak demand charging window by three hours to better align it with the times of day at which peak demand events are likely to occur. The proposed charging windows are presented in Figure 1 below.

Figure 1 - Endeavour Energy's proposed charging windows



Refinements to the estimation of LRMC

Endeavour Energy made a number of improvements to its methodology for estimating the LRMC of the services it provides. In particular, we:

- extended the evaluation period to ten years so as to better reflect the economic concept of LRMC;

- undertook a detailed analysis of the extent to which reductions in demand can contribute to replacement expenditure (repex) savings; and
- evaluated how LRMC varies across our network.

Endeavour Energy found that the LRMC of providing network services to customers in the ‘small low voltage’ tariff class varies from approximately $91/kW per annum in areas of growing demand to only $12/kW per annum in areas of falling demand. Since it is not proposing to implement regional prices in this TSS, Endeavour Energy is required to derive a single estimate of LRMC for each tariff class. For the reasons discussed in Appendix 6, we propose to base network prices on the LRMC of providing network services in areas of growing demand.

How will these reforms deliver better outcomes for customers?

Endeavour Energy has designed its proposed tariff reforms:

- to enable lower future network costs and network prices;
- to empower customers to take control of their network bill; and
- to encourage efficient investments in new technologies to the benefit of all customers.

Specifically, Endeavour’s Energy’s proposed demand tariffs will encourage customers to reduce their demand, rather than the volume of energy they use, where only the former drives Endeavour Energy’s future costs. Further, the proposed refinements to Endeavour Energy’s charging windows and modifications to its estimation of LRMC will improve the efficacy of the demand charge price signal.

The combined effect of these reforms will be more efficient decisions by customers and, as a result, the avoidance of future expenditure that would otherwise be required, which will, in turn, reduce network prices. The use of demand tariffs will also empower customers to take control of their network bill by rewarding them for reducing the extent to which they impose further costs of Endeavour Energy’s network.

Endeavour Energy’s proposed reforms will also promote efficient investments in new technologies that can provide the services customers want to use at a lower cost, which benefits both adopters and non-adopters of those technologies.

In particular, demand tariffs encourage investments in new technologies that reduce customers’ contribution to maximum demand, i.e., the driver of Endeavour Energy’s costs. These price signals enable a customer to better evaluate whether the avoided future network cost (the reduction in their network bill) is greater than the cost of a potential investment. Where the avoided future network costs exceed the cost of the investment, that investment will result in a saving for both the investing customer and all other customers.

What happens next?

The AER will make a final TSS decision on 30 April 2019.

About this Tariff Structure Explanatory Statement

CHAPTER 2

2.1 Purpose

Endeavour Energy is submitting this Tariff Structure Explanatory Statement (TSES) to the Australian Energy Regulator (AER) to accompany the TSS that Endeavour Energy is submitting to the AER in accordance with the requirements of the National Electricity Rules (the Rules). This TSES demonstrates that our TSS complies with the Rules.

The Rules require us to explain the process by which we have set our tariffs, and how that process satisfies the principles established in the Rules.

The objectives of the Rules have simple and common sense concepts behind them:

- transparency for customers on how we calculate our prices;
- transparency regarding our forward pricing reforms; and
- predictability for each individual customer on when the available prices or tariffs may apply.

Under the Rules, Endeavour Energy must set its network tariffs with reference to the efficient cost of providing distribution services to its customers. Setting tariffs that better reflect the cost of serving our customers will help both us, and our customers, make better decisions because:

- our customers gain greater flexibility to manage their network bill by changing their pattern of use of electricity – **Improving customer bill control**;

- our customers are given improved incentives to invest in solar PV, battery technology and energy efficiency where this is a more cost-effective option to network investment – **Improving incentives to invest in efficient technologies**; and

- we can better identify where and when we must invest to provide the infrastructure needed to serve our customers in cost effective an efficient manner – **Lowering costs and prices**.

Our network tariffs allow us to recover the revenue we require to provide an efficient, reliable and safe electricity network. This revenue is determined by the AER every five years.

The regulatory control period relevant to the TSS is 2019/20 to 2023/24.

Our TSS has been developed following a period of consultation with our customers and reflects our strong consideration of customer impacts through this period of transition.

2.2 Structure of this TSES

Endeavour Energy's TSES is structured as follows:

Table 1 - Structure of this document

Chapter	Title	Purpose
2	About this TSES	This section provides a purpose and structure for this TSES
3	The environment in which we operate	This section provides a description of changes in the use of our network and the implications this has for the structure and level of our tariffs over the coming regulatory period
4	Understanding our Network Prices	This section defines key terms and explains common tariff structures
5	Our customers and stakeholders	This section outlines the process we have undertaken in engaging with our customers and responds to the feedback we have received through stakeholder consultation
6	Our proposed network tariffs	This section explains the proposed changes to our network tariffs over the next regulatory period
7	Compliance with the pricing principles	This section sets out how our proposed tariff structures comply with the Pricing Principles set out in the Rules
A1	Glossary	This provides a definition for some key terms used throughout this TSES
A2	Allocation of customers to tariff classes	This section sets out the procedures that apply for the allocation of our customers to different tariff classes
A3	Proposed tariff structures – standard control services	This section provides details of the charging parameters for each of our proposed tariffs for Standard Control Services
A4	Proposed tariff structures – alternative control services	This section provides details of the charging parameters for each of our proposed tariffs for Alternative Control Services
A5	Estimating stand-alone and avoidable cost	This section sets out our approach to estimating stand-alone and avoidable cost for each of our tariff classes
A6	Estimating LRMC	This section sets out our approach to estimating long-run marginal cost for each of our tariff classes
A7	Allocation of residual costs	This section sets out the process by which we allocate residual costs between tariff components and our tariff classes
A8	Pass through of specified costs	This section provides further detail on cost items that are passed-through in our network charges
A9	Indicative pricing schedule	This section sets out indicative prices for the regulatory control period
A10	Bill impact analysis	This section sets out our analysis of the impact of proposed changes to our tariffs on those customers to whom such changes will apply
A11	Compliance checklist	This section sets out a checklist that identifying where each of the TSS Rule Requirements are met in the TSS and this TSES

2.3 Changes from our initial TSS proposal

Our initial TSS proposal was prepared in accordance with best practice principles for customer engagement and in close consultation with consumers, their representatives and retailers. A fact acknowledged by both stakeholders in submissions and the AER in its draft TSS decision.

We have continued to engage with major customer groups since the release of the AER's draft decision. They have again reiterated that our original TSS proposal remains in their best interests and we look forward to their comments on our revised TSS.

Our position now remains the same as when we submitted our original TSS. That is from a pure economic view the best outcome in order to reduce future capital expenditure requirements are for all new customers to be on a fully reflective demand tariff. However we remain concerned that this will not receive customer or political support. Without this support we risk all of the benefits of demand tariffs much like Victoria. NSW has an opportunity to be at the forefront of demand tariffs. This should not be placed at risk for the sake of economic purity.

We understand that the tariff assignment policies determined by the AER in the draft decision are designed to expedite the transition to cost-reflective tariffs; we believe, however, that this transition is too fast, impractical, and inefficient, puts at risk the tariff reform process and does not take into account customer preferences.

In response to the AER's draft TSS decision and ongoing consultation with stakeholders we will:

- Re-calculate our residential and small business demand tariffs such that the average customer is not expected to be worse-off should they opt-in to this tariff;
- Introduce an optional seasonal time of use (STOU) energy tariff for residential and small business customers;
- Retain STOU energy components within the tariffs for our Large Low Voltage, High Voltage and Subtranmission tariff class customers; and
- Further explain our tariff setting process including translating LRMC into charging parameters and allocated residual costs to tariff classes and charging parameters.

Based on customer engagement we cannot agree to the following aspects of the AER draft decision:

- The removal of the flat energy tariff as an opt-out option for customers on cost-reflective tariffs. Maintaining the legacy pricing option for customers ensures that no customer is adversely impacted by the transition to cost-reflective pricing.
- The inclusion of meter replacement as a trigger for cost-reflective tariff assignment - subsequently we also will not adopt the 12-month waiting period associated with the AER's draft decision. Re-assigning existing customers when they have not made a conscious change to their connection to the network will confuse and frustrate customers. The AER's proposed 12-month data gathering period is impractical, costly and inefficient to implement.
- The default assignment of customers to the demand tariff rather than the transitional demand tariff. The transitional tariff gives customers a chance to learn the incentives of the new cost-reflective tariff structures without the risk of significant network bill impacts. Those Customers who understand the tariff structure and respond can then elect the demand based tariff.

  The 'safe to fail' nature of the transitional demand tariff also eliminates potential system upgrade costs (which have not been included in Endeavour Energy's revised regulatory proposal), ongoing administrative cost, inconsistent treatment of consumers based on metrology and consumer frustration likely to be created by the AER's draft decision to introduce a 12-month data sampling period (discussed above).

The environment in which we operate

CHAPTER 3

3.1 Our network

We own and operate a $6.5 billion network used to transport electricity from the high voltage NSW transmission network (which is managed by TransGrid) directly to the homes and business of our customers in a form they can use. Increasing numbers of solar panels mean our network is also used to transport energy from these 'distributed' sources back into the system.

We perform this role according to extensive obligations, standards, conditions and requirements, particularly in relation to customer and community safety, and the security and reliability of supply.

Figure 2- Electricity industry structure

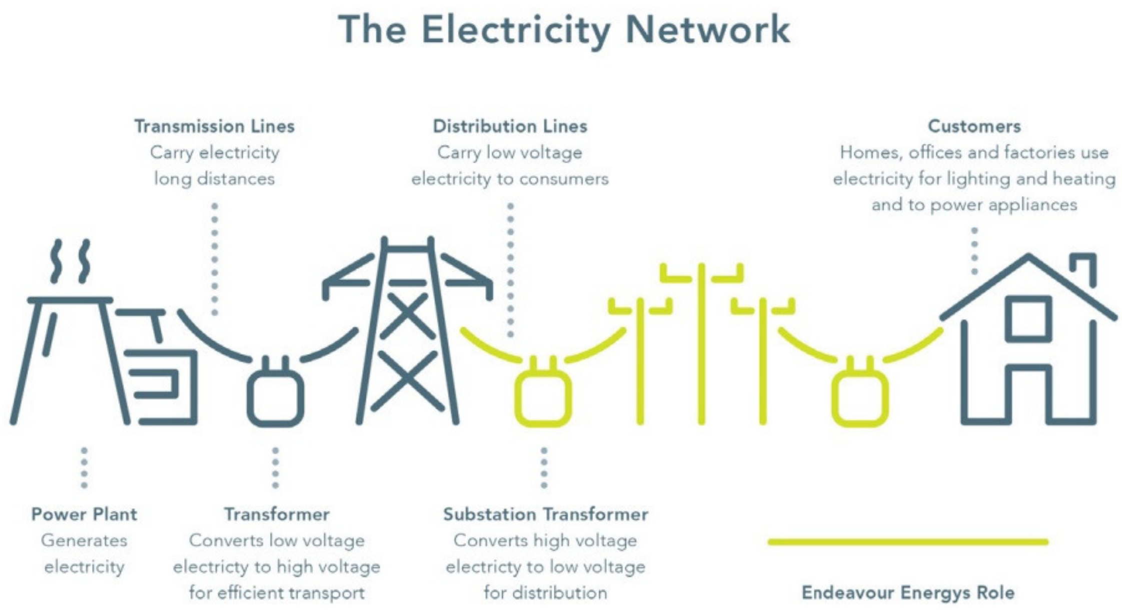


Table 2 - Residential and small business retail electricity bills

$ p.a.	Generation	Transmission	Distribution	Green schemes	Retail	Your Bill
Contribution to average household bill	41%	4%	31%	9%	15%	**100%**
Annual cost to average household	$684	$62	$508	$155	$249	**$1,657**
Contribution to median small to medium business bill	43%	4%	27%	11%	15%	**100%**
Annual cost to median small to medium business bill	$1,385	$124	$862	$366	$483	**$3,219**

3.2 Our customers

We serve a diverse population with almost 1 million customers across 24,980 square kilometres. Most of our customers are households and small to medium businesses located in urban and developing rural areas. We also serve large urban areas, medical precincts and manufacturing and industrial customers who have specific needs for a safe and reliable supply, and provide high voltage support directly to large businesses.

Our network includes significant development areas such as Sydney’s second airport, and its surrounding “Aerotropolis”. It’s also home to Sydney’s North West and South West Priority Growth sectors, planned as new release areas to house communities similar in size to Wollongong and Canberra. The population of Western Sydney is expected to swell by 900,000 over the next 20 years. That means that each year over the next decade, more than 20,000 new customers will require new electricity services.

In addition to population growth, our customers have the third highest energy density and second highest demand density in the NEM. This means that our customers consume a relatively high amount of energy, particularly during peak times (4pm to 8pm). This is largely due to a combination of higher summer temperatures (often up to 10 degrees higher than the Sydney CBD) and energy-intense economic activity.

Figure 3 - Endeavour Energy's Network Area

As the electricity industry undergoes rapid transformation, many customers are changing the way they interact with the network and we are seeing more small scale renewable forms of generation connecting to the network. Approximately111,000 customers have connected their own small scale renewable generation (mostly solar panels) to the network, representing a total capacity of around 330 MW.

Our network plays a critical role in enabling a range of customer benefits from the increasing uptake of distributed energy resources (DER). At this stage, the network support offered by DER remains limited and our peak demand will continues to grow, hitting a record high on 30 January 2017 of 4,107MW. Small scale generation is still mostly available outside of peak demand times and represents a small offset of our total energy delivered, which was 16,716 GWh for the 2016-17 year.

3.3 Supporting energy policy

3.3.1 Power of Choice

Changes to the rules governing competition in metering and related services commenced on 1 December 2017 and transfers the overall responsibility for the provision of metering services to a new participant - the Metering Coordinator. Amongst other things, the rule change is designed to facilitate a market-led deployment of advanced meters.

3.3.2 The ENA Network Transformation Roadmap

The Electricity Network Transformation Roadmap project (The ENA Roadmap) is designed to help guide the transformation of Australia's electricity networks over the 2017-27 decade toward a customer-oriented future.

The ENA Roadmap is formed from the basic expectation that modern electricity systems are efficient, reliable and safe. Increasingly, electricity systems must also create and enable new value to customers, innovative market actors and society as a whole.

The ENA's roadmap identifies the following 'Foundation' outcomes relevant to the development of our TSS:

1. Customer orientated electricity: improve trust with customers through better engagement, customised services and reform of customer protection frameworks.

2. Power system security: achieve system security with diverse generation and energy technologies.

3. Carbon abatement: enable agile connection and integration of large and small technologies.

4. Incentives and network regulation: Incentivise efficiency and innovation through fair and efficient demand based tariffs and enabling standalone systems and micro-grids.

5. Intelligent networks and markets: locational valuation of distributed energy resources.

Endeavour Energy's proposed TSS is designed to contribute, where feasible, to the achievement of the ENA Roadmap, specifically outcomes 1, 4 and 5.

3.4 Changing technology and small scale generation

3.4.1 Domestic air conditioning load

Domestic air-conditioning (AC) load is a significant driver of demand for network capacity, but the revenue recovery through energy based pricing is not commensurate with the cost of the incremental capacity. This outcome results in:

- overinvestment in AC, or at least an overinvestment in low energy efficient AC options;
- overinvestment in network capacity;
- increased network prices (prices used for “other purposes” are too high);
- under-utilisation of the network in “non-peak” times;
- the subsidisation of AC customers (the “haves”) at the expense of those without AC (the “have nots”); and
- the implementation of cost reflective pricing, which accurately signals the cost of the customer’s requirement for network capacity, and clearly differentiates between the cost of the energy provided, will address this distortion.

Such price signalling can be achieved using demand based tariff components.

However, the recovery of residual costs as either an impost on the demand based tariff components or as an impost on energy based tariff components will inevitably compromise the efficient price signal.

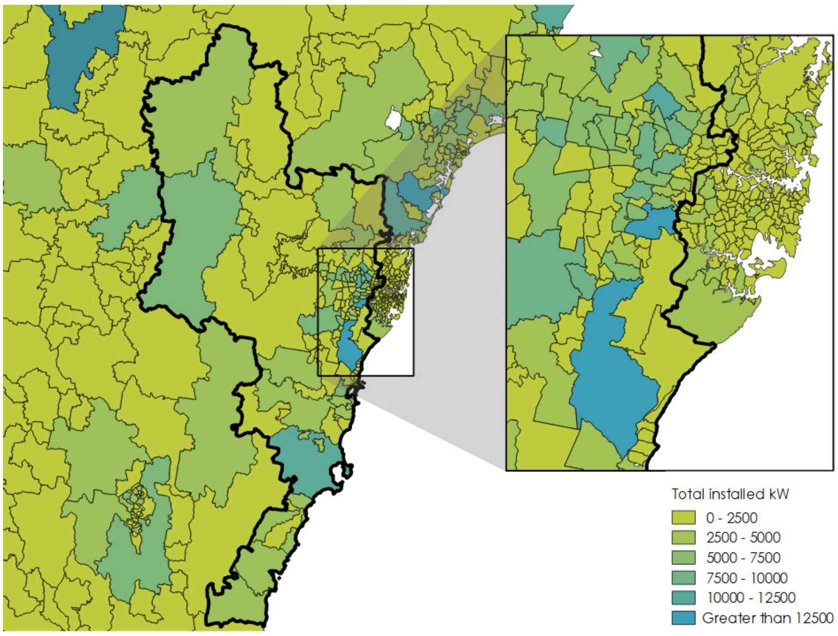
Whilst accurately signalling demand costs and over signalling energy costs (by recovering residual costs from energy based tariff parameters) might seem, from a broad societal perspective, preferable to fixed charge increases, such an approach has implications for incentivising overinvestment by customers in PV and battery systems without corresponding network cost offsets.

3.4.2 Small scale PV

While the introduction of roof top PV technology was initially driven by transparent government subsidies, hidden subsidies attributable to the shortcomings of network tariff structures also exist.

We illustrate the prevalence of solar PVs in the area covered by our network (indicated by a dark border) in Figure 4 below.

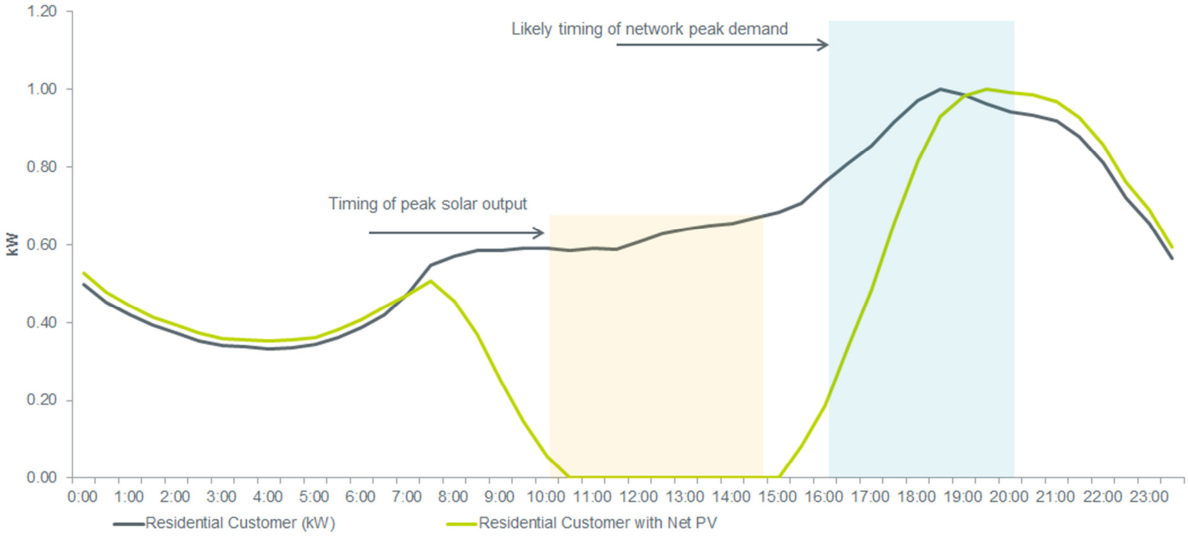
Figure 4 - PV installed capacity in the region covered by our network (dark border)



PV output, when consumed “behind the meter”, enables the owner to avoid paying the full retail value of the energy generated. This includes both the value of the energy not acquired from the network (avoided wholesale energy generation costs), but also the network’s residual and capacity based cost (LRMC) components, currently built into the network tariff energy rate.

The avoidance of this latter network component would be appropriate if the PV generation actually reduced the requirement for network capacity commensurately, but the evidence suggests that solar PV make little or no contribution to reducing system demand, as demonstrated in Figure 5 below:

Figure 5 - PV generation does not coincide with system peak events



Endeavour Energy’s peak network demand occurs in the late afternoon, well after the period of ‘peak’ solar output. Importantly, from a tariff design perspective, PV generation avoids the component of “residual cost recovery” that is also currently built into the energy charging parameter.

The avoidance of payments for energy based residual cost recovery by PV owners means that non-PV customers (typically those who rent, cannot afford the investment in PV, or for whom the option is simply not physically available), bear the additional burden of these avoided costs because, under the Revenue Cap, average prices rise. These higher prices make it even more commercially attractive to install PV (and so avoid paying the now more highly priced energy network charges).

Accurately signalling network capacity costs would ensure that, at the system level, whatever contribution PV does make to reducing peak demand, is appropriately rewarded.

However while network residual costs are recouped within the energy based charging parameter, behind the meter consumption of PV output will continue to avoid payment of these costs.

Further, increased PV penetration is likely to provide commercial incentive to ‘pair’ with a small scale battery installation.

3.4.3 Small scale battery installations

It is argued that the installation of batteries will improve network economics by enabling customers’ to shift their demand away from peak periods and thereby reduce network demands and the need for investment in network capacity.

If exposed to time based pricing, PV owners are incentivised to install batteries to store their excess PV energy accumulated during the day, when it would otherwise be exported to the network at ‘feed-in’ rates, and use it during the evening thus enabling them to avoid payment of the full retail energy rate, which is several times higher than the ‘feed-in’ rate.

Using PV energy in this way to meet evening loads should improve the underlying, systemic load profile of the customer. The issue, however, is whether the magnitude of the incentive to operate in this way is justified by the network benefit derived.

Currently, the largest component of the network energy rate is related to the recovery of residual costs that are sunk in nature. While the energy based charging parameter also serves to recover the LRMC of the capacity related costs, the current energy rate over signals the underlying LRMC benefit.

There is also the potential for inefficient arbitrage to occur between ‘peak’ and ‘off-peak’ periods where a customer has a battery installed and is supplied using an energy based TOU tariff. That is, an energy based TOU tariffs ‘peak’ signal (irrespective of the accuracy of its quantum) uniformly incentivises battery owners to load shift between ‘peak’ and ‘off-peak’ periods, even when there is no network benefit to load shifting. This is exacerbated when no seasonal signal is included in the tariff, as an inefficient load shifting incentive is provided year round.

To the extent that peak and off peak rate differentials do accurately represent the LRMC of providing network capacity, then this arbitrage would, theoretically at least, be efficient.

3.4.4 Peak demand

Peak demand is the key driver of our network costs. This is because we need to build our network sufficiently to provide safe and reliable electricity network services to our customers at all times, including on those few occasions when customers’ demand for our network services is abnormally high.

The magnitude of peak demand on our network has increased markedly in recent years driven by population growth in Sydney’s west and the prevalence of air conditioners. The uptake of solar PV and energy efficient appliances has also changed the nature of peak demand. In particular, our detailed analysis of peak demand in section 7.2 indicates that, in addition to increasing in magnitude, there is a broad trend towards peak demand events occurring later in the day.

3.5 Implications for network pricing

The way in which customers are using Endeavour Energy's distribution network is changing. It has become more important to make sure that network prices provide signals that allow customers to make informed choices about when and how to use the network, based on the costs of providing the services they use.

Under the Rules, Endeavour Energy is required to develop tariffs by reference to the efficient costs of providing services to customers.

As noted earlier, the costs of operating and maintaining a distribution network are largely fixed. However, distributors incur large, lumpy incremental costs when augmentation to the network is required to alleviate constraints at times of peak demand.

In light of this cost structure, tariffs should be designed so as to ensure that:

- the fixed costs of the network (residual costs) are recovered from all customers that use the network in a manner that does not affect their consumption of electricity (given that the fixed costs of the network do not change with the use of the network); and
- the cost of network augmentation is recovered from those customers that use the network at times of peak demand – customers that use the network at times of peak demand should be provided with an incentive to alter their consumption profile so as to reduce demand, thereby eliminating the need for network augmentation, or delaying the point at which such network augmentation is required.

An efficient price structure would, therefore have:

- recovery of the costs of the network as it stands today in the fixed components – this would imply an increase in the fixed components of our current network charges; and
- price signals to consumers as to the future cost of network augmentation reflected in the variable charge.

These changes to the level of tariff components would not change the overall amount of revenue that Endeavour Energy is allowed to collect from customers. However, they would change how much is paid by different types of customers, such that the price that each customer pays is more closely aligned with the costs that they impose on the network.

The change from existing tariff structures to those that have these characteristics will require a transition period, to avoid unacceptable impacts on customers.

Taking into account feedback from our customer engagement sessions, Endeavour Energy considers that the determining factor in relation to this balance should be the potential impact on customers.

Both of these factors argue for the speed of pricing reform to be moderate, whilst recognising that it is a process that will need to continue into the future.

Understanding our network pricing

CHAPTER 4

4.1 Defining key terms

Before setting out the types of tariffs that Endeavour Energy currently offers, it is useful to define some key terms and describe some common types of electricity tariffs offered by distributors.

Network businesses assign customers to what is termed a ‘tariff class’. A tariff class comprises a group of customers with similar characteristics. Each tariff class has one or more tariffs.

Tariffs within a tariff class can have different tariff structures. A tariff structure is made up of a number of different tariff components. For example, a tariff may comprise a fixed charge and an energy based consumption charge, which are separate tariff components within a tariff.

Charging parameters are the basis upon which a tariff component is determined. Examples of a charging parameter would be the time periods applicable to a peak energy consumption tariff component, or the consumption threshold applicable to the energy consumption blocks of a block tariff.

Once we have a tariff structure – with its tariff components and charging parameters – we set the level of each tariff component (the number of dollars per annum, per kilowatt, per kilowatt hour or per kilovolt-ampere as is appropriate for that component). We call these the price levels.

4.2 Common tariff structures

The network tariff structures we are able to adopt depend fundamentally on the type of metering technology available to measure a customer's energy consumption or demand. There are two types of meters:

- basic or accumulation meters; and
- more advanced interval or smart meters.

Basic or accumulation meters record the total amount of electricity a customer has used over a given time period between meter reads. Customers with an accumulation meter may be charged different types of tariffs on the basis of their total energy consumption. For example, common charging structures for customers with accumulation meters include:

- **Flat Tariff** - a single "flat" or "all-time" energy based variable tariff component charged on a c/kWh basis.
- **Inclining Block Tariff (IBT)** - a multi-block energy based tariff component charged on a c/kWh basis. The price level of each "block" charging parameter increases as customer consumption increases.
- **Declining Block Tariff (DBT)** - a multi-block energy based tariff component charged on a c/kWh basis. The price level of each "block" charging parameter decreases as customer consumption increases.

Interval and smart meters record a customer's electricity use down to a fraction of an hour. The primary distinction between interval and smart meters is that smart meters can communicate remotely, which allows for other services to be provided to customers. Where customers have interval or smart meters, the tariffs offered to them can be based on the timing of their electricity consumption, with different electricity rates for usage at different times of the day. For example, and in addition to the tariff options above, they may be offered a:

- **Time-of-Use (TOU) Tariff** - a multi-parameter energy based tariff charged on a c/kWh basis. The price level by charging parameter varies by the time of day that electricity is consumed. Charging parameters defined as "peak", "shoulder" and "off-peak" are generally used to define the time of day as it relates to the tariff. TOU tariffs may also contain seasonal based charging parameters (STOU);
- **Demand Tariff** - a single or multi-parameter demand based tariff charged on the basis of $/kW or $/kVA. Typically, the demand charging parameter is levied against the customer's peak consumption (measured in kW or kVA) over a defined period, commonly corresponding to the customer's billing period; and
- **Peak Time Rebate (PTR) Tariff** – a multi-parameter energy or demand based tariff charged on a c/kWh, $/kW or $/kVA basis. Typically, customers receive a bill rebate for energy or demand not used on a small number of critical days each year, as determined by the network, to reward reduced peak usage on extreme demand days.

Those tariffs that can be put in place with the use of interval or smart meters are more 'efficient', as they provide better signals to consumers regarding the costs they impose on the network.

The costs of running and maintaining a distribution network are mostly fixed. However, where demand for electricity reaches peak levels, distributors incur costs from the expansion of the network to accommodate excess demand. This typically occurs on the hottest days of the year and the peak levels of demand may only last for a short time.

The introduction of tariff structures with some 'time of use', 'demand' or 'peak pricing' component can help distributors contain their costs by reducing or deferring the need for network augmentation. This is because they allow distributors to provide price signals to customers through their retailers that encourage them to reduce their consumption at times of peak demand. By encouraging consumers to spread their consumption of electricity over longer periods of time, distributors can achieve higher utilisation of their network and lower the cost of new investment, without compromising the safety, quality or reliability of their services.

4.3 Our network tariff structures in TSS1

Endeavour Energy made a number of changes to its tariff structures as part of its first Tariff Structures Statement (TSS1). Our focus at that time was on transitioning towards having all new customers and those upgrading their network connection to 3-phase, on a more cost reflective TOU tariff.

Specifically, in TSS1, our network tariff structures were:

- a flat tariff for residential consumers with an opt-in TOU energy tariff;
- an IBT for small to medium commercial customers with an opt-in TOU energy tariff;
- demand based tariffs for large commercial customers; and
- site specific tariffs for our industrial customers.

We altered the tariff structure for existing residential customers from DBT to a flat tariff effective 1 July 2017.

By contrast, for small to medium commercial customers we have continued to charge an IBT. This continues Endeavour's strategy of creating an incentive for customers with high consumption to shift to more efficient tariff structures.

We anticipate that as interval meters are rolled out in Endeavour's area for both new customers and on meter replacement, then more customers will transition to cost reflective tariffs.

Our customers and stakeholders

CHAPTER 5

5.1 Overview

We worked hard to improve engagement with a diverse range of customers and stakeholders and to reflect their interests in our plans. We've kept downward pressure on network charges, simplified tariffs for retailers, and priced street lighting to encourage LED technology for councils.

The views of our customers and stakeholders have significantly shaped our TSS.

Our goal for this proposal has been to substantially improve our engagement approach to better reflect customers' long term interests,

We have built on the extensive customer engagement processes we undertook for our 2014-19 regulatory proposal and our first tariff structure strategy. We have also tried some new engagement techniques.

We responded to the AER's Consumer Challenge Panel feedback that more engagement was needed to support our revenue proposal and sought an extension of time from the AER to complete further customer engagement.

We responded by leading a series of 'deep dive workshops,' designed to examine our capital and operating expenditure plans in great detail with AER representatives and all stakeholder groups.

The process proved highly effective, and along with other engagement processes, helped refine and improve our proposal and customer outcomes.

Chapter 5 of our Regulatory Proposal outlines our commitment to customers and our approach to stakeholder engagement in detail. The following section summarises our intended response to customer feedback as it pertains to our future tariff planning.

5.1.1 What we heard from our customers and how we intend to respond

Table 3 - How we will respond to customer feedback

Customers and stakeholders said	We will
Affordability Affordability is the number one concern for many of our customers, but not at the sacrifice of safety or reliability. Electricity is valued because it provides security and lifestyle benefits to residential customers and communities, and because it connects new homes and underpins prosperous businesses and regions. There's a clear expectation Endeavour Energy's plans should reflect measures to continue downward pressure on our part of electricity bills, without compromising safety.	• Encourage greater efficiency in the way our network is used by introducing an opt-out seasonal demand tariff for new customer connections. • Offer customers who replace their old basic meter with a smart meter the opportunity to opt-in to our seasonal demand tariff to secure the savings it can offer. • Promote programs like *SolarSaver and CoolSaver* to educate customers through tangible personal experiences what smart meters, batteries and pricing can offer them. • Facilitate the connection of distributed energy resources including solar and batteries to help consumers control their bills.
Safety and Security Customers are concerned about a South Australian style blackout and want us to ensure this does not occur. Customers and regulators expect us to maintain high standards of workplace and community safety.	• Introduce cost-reflective pricing with a demand component. This will motivate new customers with smart meters to reduce their peak demand in order to reduce strain on the network during periods of excessive heat.

Customers and stakeholders said	We will
We also have an obligation to protect customers from cyber security risks and this requires new technology investment.	
Fair pricing Customers understand they can benefit from new ‘user pays’ ways of charging for electricity. They generally support transitioning to more efficient, cost reflective pricing with an opt-out option to the existing flat tariff as it gives them choice and control. Customer groups had concerns that charging windows were too wide and included shoulder periods, which could dilute pricing signals while retailers wanted simplicity and uniformity in order to be able to develop a marketable product and pass through our tariffs to customers.	• Introduce a seasonal demand tariff. • Replace TOU energy charging with a flat energy rate to simplify our tariff structure. • Give customers greater ability to respond to price signals by shortening our peak demand window from 1-8pm to 4-8pm on working weekdays. • Assign all new customers and existing customers who upgrade their network connection to three-phase or bi-directional flow, to the cost-reflective tariff with the option to ‘opt-out’ to the flat energy tariff. • Make the transition as easy as possible for customers with a ten-year transition for the ‘opt-out’ seasonal demand tariff and introduce a voluntary seasonal demand tariff with no transition period. • Work with retailers to help educate customers on tariff choices and with the industry as a whole to facilitate uniformity of tariff design in response to retailers’ feedback.
Transformation, choice and control Customers are keen to know more about smart meters, solar and batteries as a means to reduce/manage their consumption and their bills, and want our network to be ready to meet their future energy needs. Local councils have shown strong support for investment in new, greener technology, like extending battery storage trials to include council and commercial premises, and want a grid prepared for electric vehicles. Stakeholders expect Endeavour Energy to be innovative and trial new technologies, largely to keep downward pressure on capital expenditure, to prepare the grid for greater customer choice and to improve sustainability.	• Prudently invest in new technologies to improve automation, asset information, communication and monitoring systems, increasing our capacity to host distributed energy resources, including electric vehicles and utilise demand side response to manage network demand. • Align our direction with the CSIRO/ENA Electricity Networks Transformation Roadmap to provide more choice and control for customers and reduce the need for network investment in the long term. • Partner with local councils on technology trials and initiatives to reduce urban heat. • Prepare the network so customers can connect and use new technologies to offset their own usage and feed excess back into the network for the benefit of other Endeavour Energy customers.
Vulnerable customers Vulnerable customers want us to keep network costs as low as possible. Assisting the vulnerable is seen as the responsibility of the whole energy sector, particularly retailers. Customers have told us we should focus on assisting life	• Continue our business efficiency programs to reduce costs, which translate to savings for all customers.

Customers and stakeholders said	We will
support customers, as they depend on reliable power for life-sustaining medical equipment.	
Education and engagement Increased education and consultation are seen as important in building trust and addressing issues such as bill impacts, reducing peak demand, consumer empowerment and ensuring that the roll out of assets is timely and meets demand. The AER is seeking a frank, respectful and open conversation on customer benefits, risks and trade-offs.	• Implement a 'no surprises' approach to our expanded engagement program with all stakeholders. • Work more closely with retailers on customer education to increase their understanding of pricing and managing consumption. • Strengthen our relationship with Regional Organisations of Councils to assist them in their various local government initiatives like reducing urban heat, street lighting and vegetation management. • Adopt a long-term approach to engagement and embed effective processes in our day-to-day operations in order to keep customers' interests at the centre of our decision making.

5.1.2 Structural changes to our proposed tariffs following the 'deep dive' workshop

On 20 February 2018 detailed tariff structures were taken to stakeholders as part of our 'deep dive' consultation process. As a result of feedback received, we made significant changes to:

- the proposed structure of our cost reflective tariffs; and
- our proposed charging windows.

Both retailers and customer groups argued for greater simplicity in tariff design:

- **Retailers:** To maximise the probability of retailer pass-through of our pricing signals, the tariff structure must be both simple for them to communicate to customers and to implement in their billing systems.
- **Customer groups:** To maximise the probability that retailers pass-through the tariff structure and customers understand and respond to the tariff structure so as to access the potential benefits and savings of tariff reform.

Removing the seasonal TOU energy charge component (and replacing it with a single 'flat' energy rate) and the five-day peak demand averaging period (and replacing it with a single point monthly demand charge) was agreed by both retailers and customer groups as achieving their objective for simplicity.

Customer groups acknowledged that a single point maximum demand charge will occasionally reflect a one-off demand event but were comfortable that the monthly "resetting" of the billed demand amount would provide sufficient bill-impact mitigation without the complexity of the five-day averaging methodology.

The potential bill impact of the single point demand method is further mitigated by our strategy to introduce a transitional demand tariff over a ten year transition period.

Table 4 below summarises the key changes in the proposed structure of our cost reflective tariffs.

Table 4 - Changes to the tariff structure

Tariff	Fixed charge	Energy charges		Seasonal demand charge
		Flat	Seasonal TOU	
Tariff structure – position taken to stakeholder consultation				
Basic Metered Tariff	✓	✓	×	×
Cost Reflective Tariff	✓	×	✓	✓ (5 day average per month)
Tariff structure – revised position following stakeholder consultation				
Basic Metered Tariff	✓	✓	×	×
Cost Reflective Tariff	✓	✓	×	✓ (Single Point per month)

Table 5 below summarises the key changes in the proposed charging windows of our cost reflective tariffs.

Table 5 - Changes to the charging window

Charging window	Position taken to stakeholder consultation			Revised position following stakeholder consultation		
	Weekday High Season	Weekday Low Season	Weekend All times	Weekday High Season	Weekday Low Season	Weekend All times
Peak Energy	3 – 8pm	*n/a*	*n/a*	Removed		
Shoulder Energy	1-3pm & 8-10pm	3 – 8pm	*n/a*	Removed		
Off Peak Energy	All other times	All other times	All times	Removed		
High Season Demand	3 – 8pm	*n/a*	*n/a*	4 – 8pm	*n/a*	*n/a*
Low Season Demand	*n/a*	3 – 8pm	*n/a*	*n/a*	4 – 8pm	*n/a*

Our proposed network tariffs

CHAPTER 6

6.1 Our pricing objectives

Endeavour Energy aims to deliver electricity to customers in a way that is safe, reliable and sustainable.

Consistent with this goal, Endeavour Energy seeks to price services in a way that is transparent, equitable, predictable and efficient. More specifically, we seek to set prices that promote:

- **Fairness**: tariffs are reflective of the consumers network costs ;
- **Empowerment**: consumers are empowered to make efficient consumption choices;
- **Transparency:** ensure tariffs are simple and transparent; and
- **Predictability:** prices are predictable and stable over time.

Endeavour Energy recognises that at times there can be trade-offs between the achievement of these objectives. In particular, the transition to efficient pricing may come at the cost of simplicity and transparency and may not provide customers with the degree of predictability they desire. We will therefore pay close attention to the impact that changes to our tariff structures may have on our customers and aim to mitigate any negative impacts where possible.

In considering our future tariff strategy, Endeavour Energy needs to balance:

- prices that promote the efficient use of the network and network investment into the future;
- recovery of the regulated revenue the AER has allowed us; and
- the transitional bill impacts on some customers in moving towards more efficient structures.

We consider the transition to efficient pricing to be a long-term goal that will be best achieved by learning from experience and working with our customers to develop tariff structures that best meet their needs.

We consider these pricing goals to be consistent with the Network Pricing Objective and the Pricing Principles as set out in the Rules.

6.1.1 Proposed tariff classes

Our tariff classes for standard control services have changed to replace our current TOU tariffs with demand based tariff options for residential and small to medium business customers. This decision to remove our TOU charges resulted from direct consultation with our stakeholders and will simplify our tariffs while improving both the cost reflectiveness of our tariffs and our customer's ability to manage their bills.

Our existing Low Voltage Energy and Low Voltage Demand classes will be renamed Small Low Voltage and Large Low Voltage, respectively. All of our customers will be assigned to a tariff class for one or more of these services.[1]

Our tariff classes for these customers are set on the basis of:[2]

- the nature of the customers' connection to the network, i.e., whether they are high or low voltage customers or whether they are metered or unmetered; and
- the nature and extent of customers' usage, i.e., above or below a specified level of consumption per annum.

A summary of our network tariff classes is set out in Table 6 below:

[1] As required under the Rules, Clause 6.18.3(b) and (c).
[2] As required under the Rules, Clause 6.18.4(a)(1).

Table 6 - Endeavour Energy network tariff classes

Customer type	Tariff class	Connection characteristics
Residential and small to medium enterprise businesses	Small Low Voltage	LV Connection (230/400 V) Total electricity consumption, per financial year, is less than 160MWh
Larger commercial and light industrial	Large Low Voltage	LV Connection (230/400 V) Total electricity consumption, per financial year, is greater than 160MWh
Industrial	High Voltage Demand	HV Connection (12.7 kV SWER, 11 or 22 kV)
Industrial	Subtransmission Demand	ST Connection (33, 66 or 132 kV)
Distributors	Inter-Distributor Transfer Demand	Distributor Transfer
Unmetered	Unmetered Supply	Unmetered

We consider our existing tariff classes to be economically efficient.[3] This is because customers within each of our existing tariff classes place similar demands on our network – by grouping our customers into these network tariff classes we believe that customers with similar characteristics and similar demands on our network will pay similar prices.[4]

We also consider that the retention of our existing tariff classes will avoid unnecessary transaction costs that would arise from customers switching to new tariff classes, additionally:[5]

- we received no feedback from our customer engagement to suggest that customers are not satisfied with our existing tariff classes; and
- in the absence of strong discontent with our existing tariff classes, we see little reason to subject our customers, or retailers, to the costs of transitioning to alternative tariff classes.

Our tariff class definitions ensure customers with micro-generation facilities are allocated to the same tariff class as those customers without such facilities, but with a similar load profile.[6]

In addition to our standard control services, Endeavour Energy provides customer specific or customer requested services, and so the full cost of the service is attributed to that particular customer. These are referred to as alternative control services. One of the defining characteristics of these services is that the AER determines the price for the service or the unit rates used in quoting for a service.

The AER has classified the following categories of direct control services as alternative control services:

- ancillary network services;
- metering;
- public lighting; and
- security lights (Nightwatch)

[3] As required under the Rules, Clause 6.18.3(d)(1).
[4] As required under the Rules, Clause 6.18.4(a)(2).
[5] As required under the Rules, Clause 6.18.3(d)(2).
[6] As required under the Rules, Clause 8.18.4(a)(3).

Endeavour Energy proposes that customers that use these categories of service form our alternative control service tariff classes. A summary is set out in Table 7 below:

Table 7 - Endeavour Energy alternative control tariff classes

Customer type	Tariff class	Service characteristics
Retailers and ASPs on behalf of customers	Ancillary Network Services	Would include authorisations, inspections, permits, site establishment, connections/disconnections and conveyancing information. Service is initiated only at customer request.
Low voltage customers consuming less than 160MWh p.a.	Metering	Provision of Type 5 and Type 6 metering assets. Meter reading services for Type 5 and 6 metering assets. Retirement of Type 5 and 6 metering assets.
Public space illuminators (generally local councils)	Public Lighting	Provision of public lighting infrastructure. Maintenance of public lighting infrastructure. Retirement of public lighting infrastructure.
Customer requested flood lighting services	Security Lights (Nightwatch)	Provision of lighting infrastructure. Maintenance of lighting infrastructure. Supply of energy for lighting service.

We consider our proposed alternative control service tariff classes to be economically efficient.[7] This is because customers within each of our existing tariff classes place similar demands on our resources – by grouping our customers into these network tariff classes we believe that customers with similar service requirements will pay consistent prices as determined by the AER's form of control.

6.1.2 Allocation of customers to tariff classes

The AER is required to decide on the principles governing the assignment or reassignment of retail customers to or between Endeavour Energy's tariff classes under cl 6.12.1(17) of the Rules.

We accept the procedures for assigning retail customers to tariff classes as outlined in Appendix D of the AER's draft decision. These procedures are replicated in Appendix 2.[8]

The process under which new customers are assigned to network tariff classes and network tariffs occurs following the receipt of a connection application by the customer or their retailer. Customers will be assigned or reassigned to network tariff classes in accordance with the criteria described in section 6.1.1. Under our process, a customer that lodges an application to modify or upgrade an existing network connection is treated identically to a new customer.

[7] As required under the Rules, Clause 6.18.3(d)(1).
[8] These procedures meet various requirements under the Rules as set out in Clause 6.18.

6.1.3 Our proposed network tariff structures

Endeavour Energy is proposing to make two key changes to our network tariff structures as part of this TSS, namely:

- introducing demand based tariffs and a STOU energy tariff to replace the current TOU tariffs to provide a clearer and simpler signal to customers about the costs they impose on the network by their use during peak periods; and
- realigning the peak charging period for these tariffs to more closely align the peak period to the times at which network usage peaks arise.

The demand based tariffs will be introduced for residential and small business customers, and will represent a substantial shift towards cost reflectivity in Endeavour Energy's pricing structures.

Two demand based tariffs are proposed for each of the residential and small business customer segments, namely:

- a cost reflective demand tariff; and
- a transitional demand tariff.

Each tariff will consist of three tariff parameters: a seasonal maximum monthly demand charge, a flat energy charge and a fixed charge.

The demand tariff parameter will be calculated using a single point maximum demand charge on a $/kW/month basis. This design was seen by both retailers and customer groups as a simplistic and effective option that is easily understood by consumers.

The demand charge of the transitional demand tariff will initially be lower than that of the cost reflective demand tariff, with a higher flat energy charge, both of which will transition to the cost reflective tariff over 10 years. This transitional demand tariff will allow Endeavour Energy to manage the path of residential and small business customers to the fully cost reflective demand tariff over time.

We do not accept the AER's draft decision to assign replacement meter customers to cost reflective tariffs. However, our proposed default transitional demand tariff provides a more practical alternative to the AER's draft decision to introduce a 12-month data sampling period before triggering a tariff reassignment. The transitional demand tariff achieves the AER's goal to improve consumer understanding and acceptance of cost reflective tariffs. Over this TSS period, the demand charging parameters of the transitional demand tariff will account for only a small, but observable percentage of the customer's network bill. Once a consumer understands the operation of the transitional demand tariff, the cost-reflective demand tariff is then available to them as an option to better manage their network bills.

The 'safe to fail' nature of the transitional tariff also eliminates potential system upgrade costs (which have not been included in Endeavour Energy's revised regulatory proposal), ongoing administrative cost, inconsistent treatment of consumers based on metrology and consumer frustration likely to be created by the AER's draft decision to introduce a 12-month data sampling period.

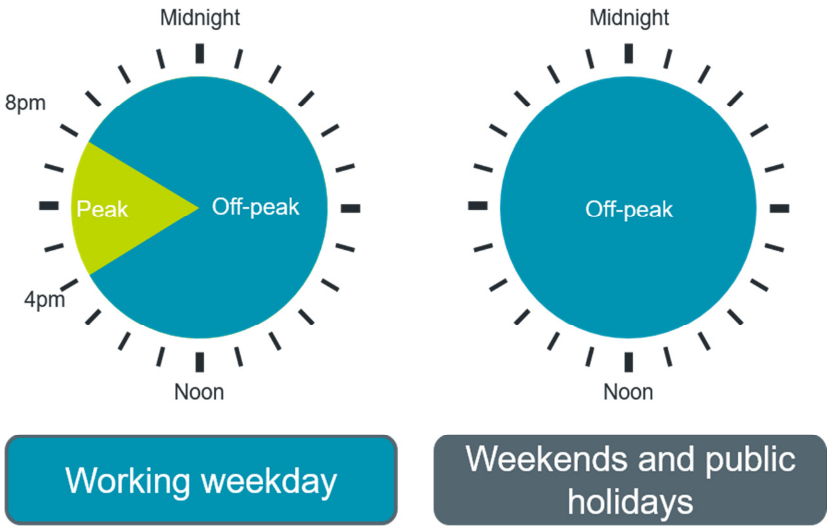
We will also offer an opt-in demand tariff set at the full cost reflective charge for customers who are able to make use of this tariff now.

While we do not agree with the AER's draft decision requiring us to maintain energy based TOU tariffs, we accept that the implementation of a STOU tariff provides an additional, though inferior, cost-reflective tariff option for consumers.

The STOU tariff will consist of two tariff parameters: seasonal TOU energy charges and a fixed charge.

From our analysis outlined in Chapter 7,and accepted in the AER's draft decision, the maximum monthly demand will be based on maximum demand only during periods when the congestion on our network is likely to be highest, i.e., from 4pm to 8pm on working weekdays. The level of this charge will be seasonal, with a higher charge in the typically hot months from November to March and a lower charge in all other months.

Figure 6 - Our proposed charging windows



The principal merits of Endeavour Energy's proposed demand tariffs are:

- **Empowerment** - they more effectively signal to customers the network costs that arise from further use of the network at peak times, which provide customers with the information they require to make decisions about network use and investments in new technologies that best meet their needs at least cost;
- **Fairness** - promotes the equitable treatment of adopters and non-adopters of new technologies like solar PV and batteries since it encourages investments that reduce our network costs (peak demand), rather than energy consumption, which benefits adopters and non-adopters;
- **Transparency** – they are straight forward to understand and include no more than three charging parameters; and
- **Predictability** – customers pay a network bill that better reflects the costs of their use of the network.

As discussed in section 2.4 above, we do not accept the AER's draft decision as it pertains to tariff assignment. The tariff assignment policies detailed in our initial TSS proposal where formed with the input of numerous stakeholders. We do not believe that the AER's draft decision on tariff assignment reflects the principles of best practice consumer engagement.

Our revised TSS proposal is, therefore unchanged from our initial TSS proposal in that we will modify our tariff allocations policy by requiring existing customers who upgrade their network connection to bi-directional flow (i.e., to support the feeding in of electricity to the network produced by on-site solar PV) to be assigned to the opt-out transitional demand tariff. This change is to ensure that those customers face more cost reflective prices, and so take this into account when making decisions about investing in solar PV technologies.

As in our preceding TSS, the remaining network tariff structures (i.e., in addition to the residential and small business demand and STOU tariffs) are:

- a flat tariff for residential customers;
- an IBT for small to medium commercial customers;
- demand based tariffs for large commercial customers; and
- site specific tariffs for our industrial customers.

The proposed changes to tariff allocation procedures in TSS1, will remain as part of TSS2, specifically:

- customers on existing tariff structures can continue to remain on those tariff structures;
- new customers will be assigned to the transitional demand tariff with the option to opt-out to the flat energy tariff for residential customers and to the IBT for small to medium business customers;
- existing customers who choose to modify or upgrade their existing network connection from single to three phase or bi-directional flow will be assigned to the transitional demand tariff (if their metrology allows) with the option to opt-out to the non-time of use tariff; and
- all existing customers have the option to opt-in to the transitional or cost-reflective demand tariff on a voluntary basis.
- all existing customers have the option to opt-in to the STOU energy tariff on a voluntary basis.

Endeavour Energy's proposed network tariff structure and allocation changes reflect a balancing of the desirability to transition quickly to cost reflect tariff structures, while managing customer bill impacts, as outlined in further detail in Appendix 10.

A more detailed explanation of the type of tariffs offered to customers in each of our tariff classes, and a description of the customers that are eligible for each is set out in the sections below.[9]

An indicative pricing schedule for each of our tariff classes, setting out the parameters of each of our tariffs over the TSS period is set out in Appendix 9.

[9] During the TSS period, Endeavour Energy may need to introduce new tariff codes for billing purposes. Any new tariff codes introduced will comply with the tariff structures outlined in this document for each tariff class and the price level for NUOS services will equate to the tariff type under which the new tariff code has been created.

6.2 Small low voltage tariff class

The tariff structures available for residential customers in the small low voltage tariff class are:

- a flat energy tariff with a fixed charge for residential consumers;
- a transitional demand tariff, which has a seasonal demand based charge, a flat energy consumption charge and a fixed charge;
- a demand tariff, which has a seasonal demand based charge, a flat energy consumption charge and a fixed charge; and
- a seasonal time of use energy tariff, which has seasonal time of use energy consumption charges and a fixed charge.
- An obsolete time of use energy tariff that has time of use energy consumption charges (under our existing, obsolete charging windows) and a fixed charge. This tariff is closed to new entrants. Customers on this tariff will be reassigned to the default demand cost-reflective tariff as a priority or the STOU if the bill impacts do not allow. This transition is expected to occur by year three of the regulatory control period.

The tariff structures available for non-residential customers in the small low voltage tariff class are:

- an IBT with a fixed charge for small to medium commercial customers;
- a transitional demand tariff, which has a seasonal demand based charge, a flat energy consumption charge and a fixed charge; and
- a demand tariff, which has a seasonal demand based charge, a flat energy consumption charge and a fixed charge.
- a seasonal time of use energy tariff, which has seasonal time of use energy consumption charges and a fixed charge.
- An obsolete time of use energy tariff that has time of use energy consumption charges (under our existing, obsolete charging windows) and a fixed charge. This tariff is closed to new entrants. Customers on this tariff will be reassigned to the default demand cost-reflective tariff as a priority or the STOU if the bill impacts do not allow. This transition is expected to occur by year three of the regulatory control period.

We will continue to offer our optional controlled load tariffs – these tariffs apply to any customer that has a residential or general supply tariff – the electricity load is separately metered and controlled at a connection point.

Our tariff assignment policy aims to place our customers on the most appropriate tariff. From 1 July 2019:

- new customers (all of whom will have interval meters under competitive metering) will be assigned to the default transitional demand tariff, with the option to opt-out to the flat energy tariff;
- existing customers that can be identified as having upgraded their network connection to 3-phase or bi-directional flow will be assigned to the default transitional demand tariff, with the option to opt-out to the alternate cost reflective tariffs or the flat energy tariff; and
- existing customers with interval meters will remain on their existing tariff (i.e., a flat tariff or IBT as appropriate), with the option to opt-in to the transitional demand tariff, demand tariff or STOU tariff.

Finally, Endeavour Energy recognises that the inclining block tariff does not minimise price distortions to the price signals for efficient usage of the network, but has historically maintained this structure to incentivise customers with high consumption to transfer to the more efficient demand tariff structure. The vast majority (97.8%) of customers on the general supply tariff consume less than 120MWh per annum. Therefore, maintaining the consumption threshold at which the second block commences (120MWh per annum) will continue to provide a long term signal for larger customers on the tariff to switch to a more efficient tariff, whilst minimising distortions to the vast majority of customers on this tariff. We believe this approach is consistent with the twin principles of minimising customer impact and promoting customers moving to more efficient tariffs.

The parameters and indicative price levels of each of the tariffs in this tariff class are set out in Appendix 9.

6.3 Large low voltage tariff class

The tariff structures available within the large low voltage tariff class are:

- a demand tariff, which has a seasonal demand based charge, seasonal time of use energy consumption charges and a fixed charge; and
- a transitional energy tariff with seasonal time of use energy consumption charges and a fixed charge.

The demand tariff is the default tariff for customers that consume more than 160MWh per annum.

The transitional large LV demand tariff is a mandated transitional tariff for customers whose annual consumption requires a demand based tariff, but who cannot be directly transferred to the default demand tariff due to a lack of metering capable of supporting this tariff or where the expected bill impact of a direct transition to the demand tariff is deemed excessive. The transition tariff is not available on customer or retailer request.

The parameters and indicative price levels of each of the tariffs in this tariff class are set out in Appendix 9.

6.4 High voltage demand tariff class

The tariff structures available within the High Voltage (HV) Demand tariff class are:

- a HV demand tariff, which has a seasonal demand based charge, seasonal time of use energy consumption charges and a fixed charge; and
- an individually calculated HV demand tariff with the same structure as the HV demand tariff.

Our HV demand tariff is the default tariff for customers where electricity is supplied at a voltage level defined as high voltage.

Our individually calculated HV demand tariff is a customer specific tariff applied where the customer's:

- electricity consumption has been equal to or greater than 100 GWh in total for the 36 months preceding the application; or
- electricity consumption has been equal to or greater than 40 GWh per annum in each of the two financial years preceding the application; or
- monthly peak demand has been equal to or greater than 10 MVA for 24 of the 36 months preceding the application.

The parameters and indicative price levels of the HV demand tariff are set out in Appendix 9.

6.5 Subtransmission demand tariff class

We plan to offer two network tariff types within the subtransmission demand tariff class:

- a ST demand tariff, which has a seasonal demand based charge, seasonal time of use energy consumption charges and a fixed charge; and
- an individually calculated ST demand tariff with the same structure as the ST demand tariff.

Our ST demand tariff is the default tariff for customers where electricity is supplied at a voltage level defined as subtransmission voltage.

Our individually calculated ST demand tariff is a customer specific tariff applied where the customers:

- electricity consumption has been equal to or greater than 100 GWh in total for the 36 months preceding the application; or
- electricity consumption has been equal to or greater than 40 GWh per annum in each of the two financial years preceding the application; or
- monthly peak demand has been equal to or greater than 10 MVA for 24 of the 36 months preceding the application.

The parameters and indicative price levels of the ST demand tariff are set out in Appendix 9.

6.6 Inter-distributor transfer demand tariff class

We plan to offer one network tariff type within the inter-distributor tariff class, being the inter-distributor demand tariff. This tariff is a mandated, distributor specific demand tariff for electricity transferred through the Endeavour Energy network on behalf of Ausgrid and Essential Energy.

6.7 Unmetered supply

We plan to offer one network tariff type within the Unmetered Supply tariff class, being an unmetered energy tariff.

We plan to offer four unmetered energy tariffs for the specific purpose of:

- unmetered energy (the default tariff for customers in this tariff class);
- streetlighting connection points;
- traffic control signal lights connection points; and
- security lighting (nightwatch) connection points.

The parameters and indicative price levels of the unmetered supply tariffs are set out in Appendix 9.

Compliance with the pricing principles

CHAPTER 7

7.1 Overview

Our proposed tariffs are consistent with the Pricing Principles as set out in the Rules. More specifically:

- our tariffs reflect the efficient costs of providing the services;[10]
- our tariffs for each tariff class lie between the stand-alone and avoidable cost of serving our customers;[11]
- our tariffs are set by reference to LRMC, with allowance for the recovery of residual costs;[12] and
- our tariffs mitigate impact on customers.

In setting our tariffs, we have had consideration for the impact that changes to our price levels will have on our customers.

7.2 Tariff Setting Methodology

Endeavour Energy sets price levels in two steps. First, costs are allocated to individual tariffs and, second, the structure of charges within each individual tariff is determined.

We allocate costs to individual tariffs by:

- allocating every tariff the LRMC of the distribution network, consistent with clause 6.18.5(f) of the Rules; then
- allocating the residual costs to each tariff by taking into account the previous years' allocation of residual costs and a targeted residual cost allocation where costs are allocated based on:
    - Shared network asset costs for individually calculated, site specific tariffs; and
    - Diversified contribution to peak period demand for 'postage stamp' tariffs

In our view, this approach appropriately takes into consideration the impact on retail customers of changes in tariffs from the previous regulatory year consistent with clause 6.18.5(h) of the Rules.

The costs allocated to each tariff are then converted to a charging structure, which may include a fixed charge, consumption charge and/or demand charge. The structure of charges within each tariff are determined on the following basis:

- For demand tariffs and seasonal TOU tariffs, we propose to signal to customers the LRMC of providing network services at times of greatest utilisation using the demand charging parameter in demand tariffs and the peak energy charge in seasonal TOU tariffs. The demand/peak consumption charge was selected because it provides a signal to customers that more closely reflects the driver of network costs (i.e. peak demand).
- Costs not recovered from demand charges or peak energy charges are recovered from either fixed charges or consumption charges (kWh charges). In the absence of reliable information on the price elasticity of demand, this allocation is guided by a rebalancing of the recovery of costs towards fixed charges and away from distortionary consumption-based charges, subject to the extent this rebalancing can be achieved without unacceptable network bill impacts for our customers.

The extent to which we can move towards LRMC-based charging and higher fixed charges is constrained by prioritising the management of customer bill impacts.

[10] As required under the Rule 6.18.5(a).
[11] As required under the Rule 6.18.5(e).
[12] As required under the Rule 6.18.5(f).

7.3 Tariffs reflect the efficient costs of providing the services

Clause 6.18.5(f) of the Rules prescribes that:

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.

However, the long run marginal cost (LRMC) of the network services we provide to customers is not constant through time and, on a particular part of our network, LRMC may be:

- low when there is excess capacity; and
- relatively higher when that element of our network approaches full utilisation.

The Rules therefore provide guidance as to the approach applied to estimate LRMC by requiring it to be calculated by reference to:[13]

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

Since LRMC is estimated at 'times of greatest utilisation' it follows that the provision of LRMC-based price signals should correspond with those periods. We explain below how we determined the months, days and times of day (charging windows) that our LRMC-based demand prices apply.

7.3.1 The introduction of seasonality (different charging windows depending on the time of the year)

Temperature is the underlying driver of peak demand on our network because it drives customers' use of energy intensive cooling (air-conditioning) and heating appliances. Specifically, the use of air conditioners during periods of extreme hot temperatures is the primary driver of peak demand on our network. By way of example, every system peak demand event in the last five years occurred in the summer months.

It is for this reason that we propose to improve the efficiency of our tariffs by introducing a demand tariff to reflect the seasonal nature of peak demand. In other words, we propose to introduce seasonal peak pricing where by demand charges are higher in those months of the year when peak demand events are likely to occur – the 'high season'. This will improve the efficiency of our tariffs by better aligning the application of our LRMC-based peak prices with the 'times of greatest' utilisation' on our network.

Given the concentration of peak demand in the summer months, we propose to introduce seasonality in our demand tariffs by charging a higher demand charge during the 'high season', which we define as the period from 1 November to 31 March.

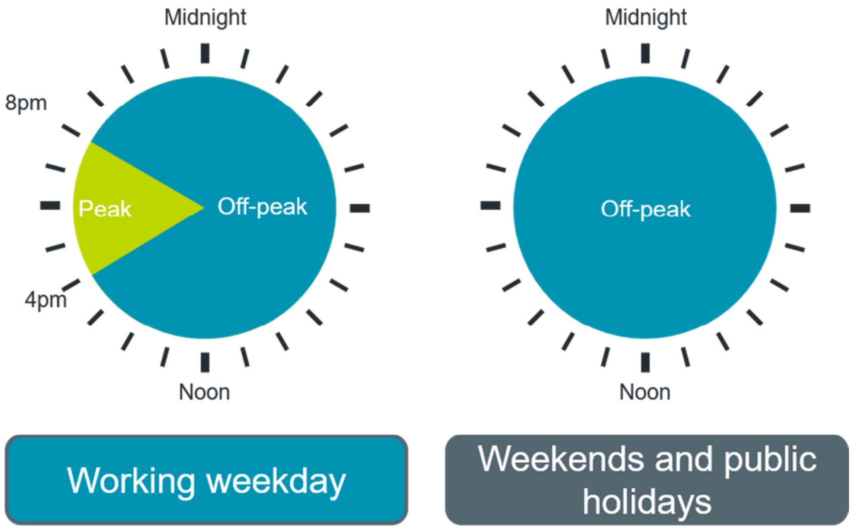
7.3.2 Reforming our charging windows

The AER has accepted our initial TSS proposal to narrow the peak charging window in the high-season by three hours. This will improve the efficiency of our cost reflective tariffs by better aligning the peak charging window with the times of the day at which peak demand is most likely to occur.

We present our proposed charging windows in Figure 7 below.

[13] As Required under the Rule 6.18.5(f)(2).

Figure 7 - Our proposed charging windows



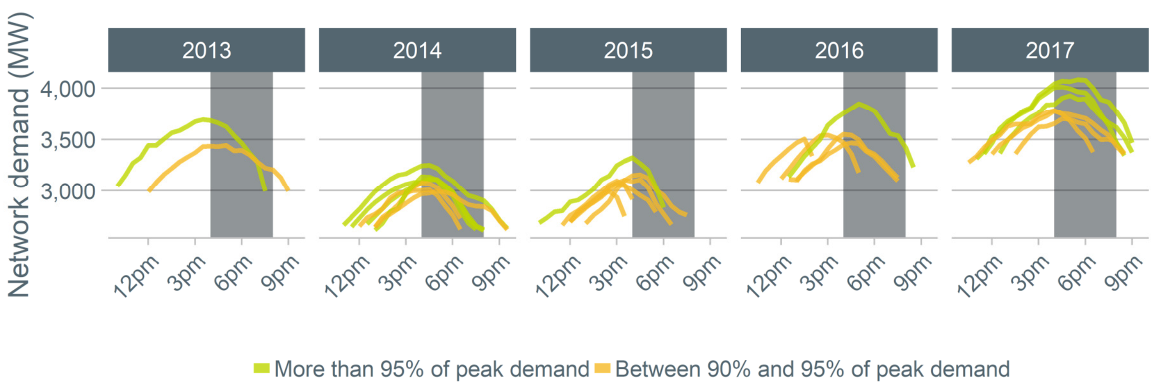
These reforms to our charging windows are supported by our analysis of the timing of peak demand:

- at the network level;
- in each of the regions that comprise our network;
- at the assets/locations where demand is driving our forward-looking costs; and
- the timing of peak demand at the network level

The starting point in our analysis of peak demand was at the network level, consistent with the approach approved by the AER in our first TSS.

Figure 8 shows the load profile on those days where maximum demand reached at least 90 per cent of system maximum demand for the year, where our proposed peak charging window is shaded dark grey.

Figure 8 - The timing of peak demand days within 90% of peak demand for the financial years 2013-17



We find that there is considerable diversity in the time of day at which the network peak demand occurs and, to a lesser extent, in the load profile on peak days. For example, peak demand in 2013 occurred close to 3pm, but much later in the day in 2017. This also illustrates a broad trend towards peak demand occurring later in the day, which underpins our proposal that the peak period starts at 4pm, rather than 1pm.

In summary, the significant diversity over the years in the timing of peak demand at the network level emphasises the importance of a relatively broad peak charging window from 4pm to 8pm. The timing of this charging window has been supported by our stakeholders as both reflecting the underlying costs of our network while still being narrow enough to allow customers to manage their bill impacts.

We will continue to monitor the extent to which network peak demand continues to occur later in the day and whether it warrants a further narrowing of the peak period in the future.

The timing of peak demand in different areas

Like all networks, we measure total demand as the sum of demand at each location of our network at a particular time. While this is helpful for understanding how demand is changing across our entire network, our need to provide safe and reliable services at each and every location in our network which means that our forward-looking costs are affected principally by location-specific peak demand, rather than system wide peak demand.

We have therefore also considered the extent to which there is diversity in the timing of peak demand across each of the regions that comprise our network. This ensures that our charging windows appropriately capture the diversity in the timing of peak demand at different locations in our network.

Our analysis shows that the timing of peak demand across our network is much more diverse than the timing of network peak demand. To illustrate this, Figure 9 presents the load profiles on the top five demand days in 2017 at a selection of bulk supply points for which peak demand occurs in the high-season.

Figure 9 - Top five peak days at bulk supply points in summer peaking regions in 2017

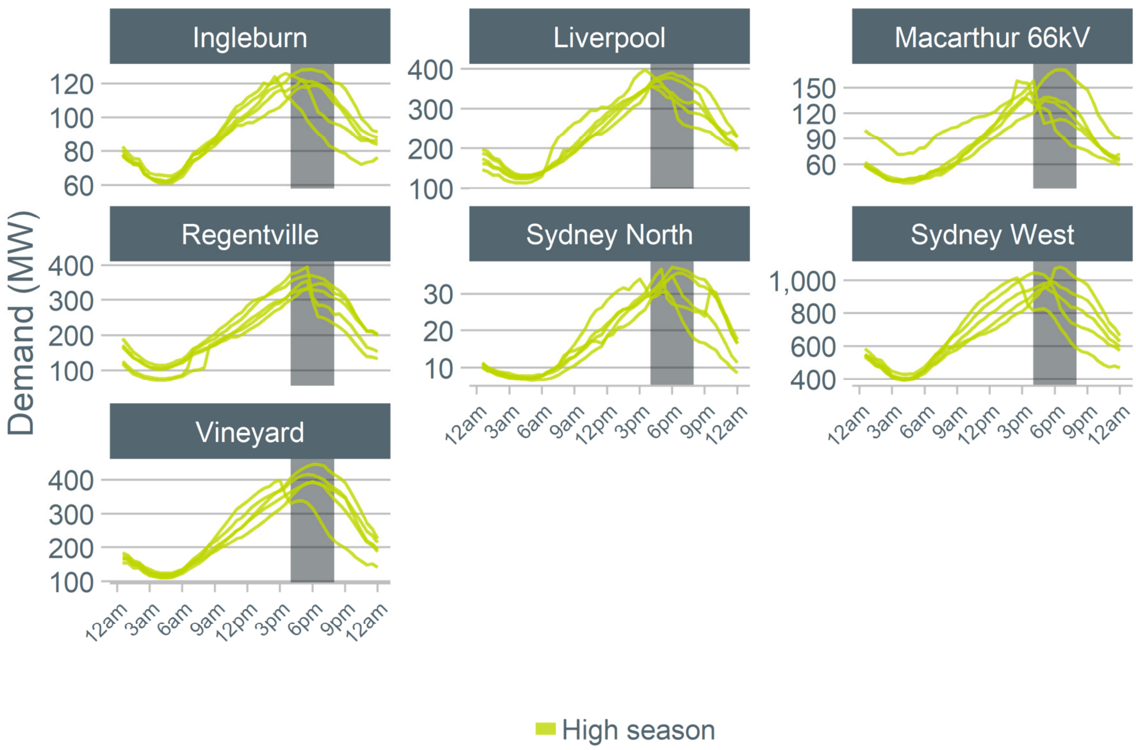


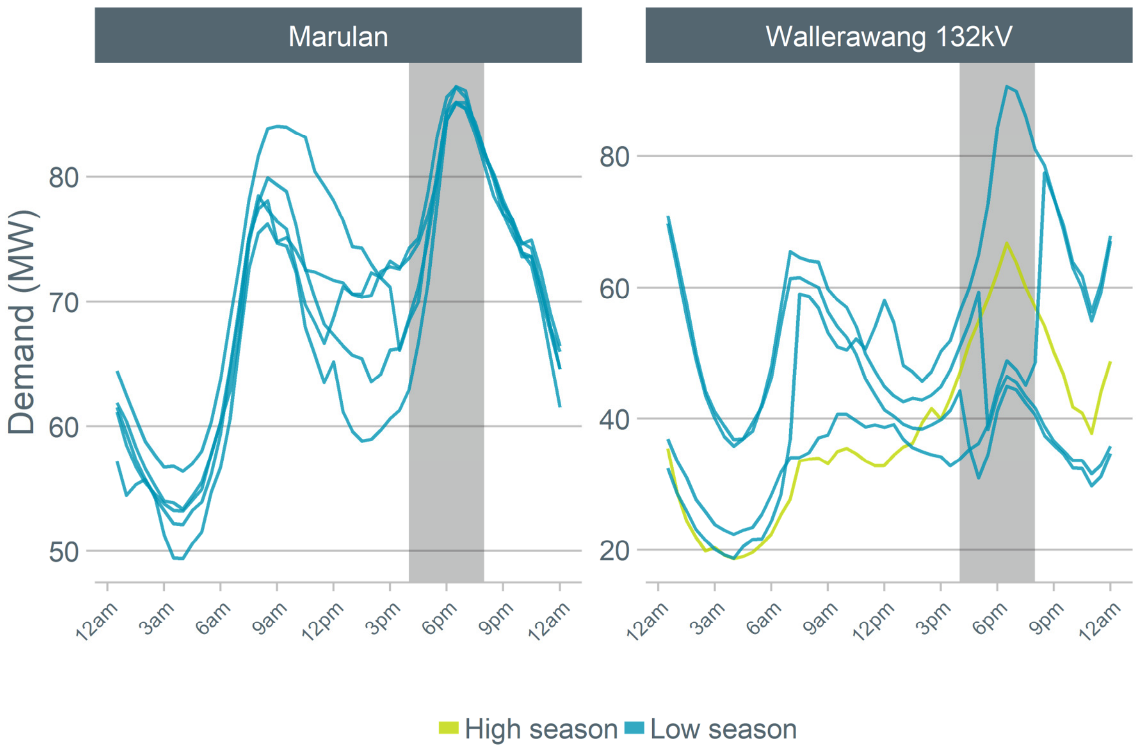
Figure 9 illustrates the substantial diversity in the timing of peak demand across our network and the importance of a sufficiently broad peak charging window. For example, if the peak charging window started later, at say 5pm, we would risk missing location-specific peak demand events that would send inefficient price signals to customers. This could exacerbate peak demand in these locations and increase our network costs to the detriment of the long-term interest of our customers.

Our analysis of peak demand across our network shows that a peak charging window from 4pm to 8pm is required to capture the diversity in the timing of locational peak demands across our network.

It is relevant to note that there are a small number of regions in our network – generally located in inland NSW or on the south coast – where peak demand typically occurs in the low-season. Peak demand in these regions generally occurs later in the day and exhibits a narrower peak, as compared with regions that peak in the high season. We therefore propose to apply a shoulder charging window in the low-season and, for simplicity, to align the shoulder period with the times at which the peak period applies in the high-season, i.e. so that the highest of the applicable charges in the high and low season apply during the same times.

We consider the economic efficiency benefits of a narrower shoulder period in the low-season are not material, and would be outweighed by the unnecessary complexity and confusion for customers. For completeness, Figure 10 presents the load profiles for the top five peak events for two winter peaking bulk supply points, both located in inland areas.

Figure 10 - Top five peak days at the bulk supply point level for winter peaking regions in 2017



The timing of peak demand that is driving our costs

The most granular level of our analysis involved an evaluation of location-specific peak demand that is driving our future costs. In other words, we examined the timing of peak demand at distribution zone substations that are approaching capacity. Demand at these substations is expected to trigger the consideration of expenditure options for ensuring we continue to provide a reliable service to those customers, which may include demand management, load shifting, or augmenting the network to cater for increased levels of demand.

This analysis reflects the AER's comments in its final decision on our first TSS that:[14]

It is network constraints–the relationship between demand levels and asset capacity–that drive investment decisions… We encourage Endeavour Energy to investigate how it can incorporate network capacity into the curves, rather than just demand levels in isolation.

In response to the AER's comments, we identified seven distribution zone-substations for which demand is approaching rated capacity, or is expected to over the next five to ten years. Figure 11 shows the forecast maximum demand at these distribution zone-substations in green, as compared

[14] AER, *Final decision – tariff structure statements - Ausgrid, Endeavour and Essential Energy,* February 2017, p.125.

with their current rated capacity (in orange), along with the potential level of expenditure in future years.

Figure 11 - Forecast maximum demand and capital expenditure in constrained zone substations

A peak charging window that does not coincide with the timing of peak demand at these zone substations will result in us providing inefficient price signals that exacerbate peak demand and potentially increase our network costs. We therefore examined the timing of peak demand at these substations on the top five demand days in 2017, which all occur in the high season. This analysis is presented at Figure 12.

Figure 12 - Top five peak days at growing zone substations in 2017

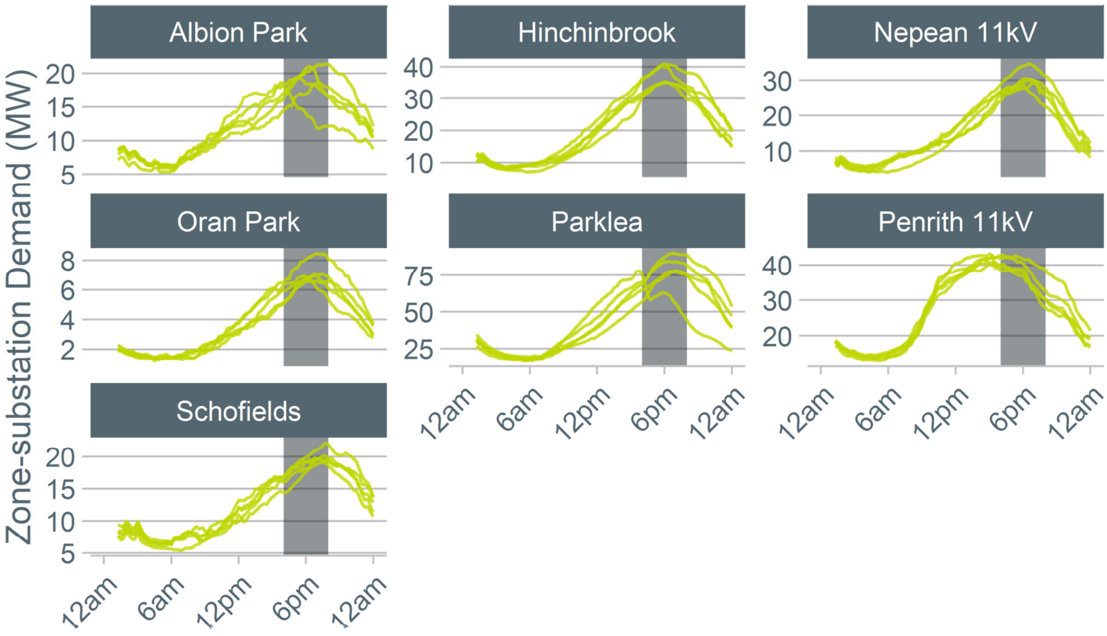


Figure 12 shows that peak demand at these substations generally occurs late in the day, with the exception of the Penrith 11kV substation which has a higher proportion of general supply customers and exhibits a flatter load profile and a peak that occurs much earlier in the day. Owing to the shared use of our assets by residential and business customers it is important that our peak charging window is sufficiently wide to capture peaks in demand driven by:

- residential customers – which generally occur later in the day as people arrive home from work; and
- business customers – which generally occur earlier in the day and exhibit a less pronounced peak.

Further, we note that on days of extreme temperature at predominantly residential substations, such as Parklea, demand can reach near-peak levels much earlier in the day than would typically be expected at a predominantly residential substation.

We conclude from this analysis that our proposed charging windows adequately capture the timing of peak demand that is driving our forward-looking costs. This will ensure that efficient LRMC-based price signals are provided to these customers at the times of peak demand that are driving our costs.

Summary of our analysis of peak demand

We conclude from our analysis that there exists considerable diversity in the timing of peak demand across our network. At a network level, we observe that peak demand generally occurs between 4pm and 8pm and that in more recent years peak demand appears to be occurring later in the day.

However, when we evaluate the timing of peak demand across the different regions that comprise our network it is clear that this trend is not pervasive across our network and that peak levels of demand occurred as early as 4pm in 2017. We therefore conclude that, currently, a peak period that started later than 4pm would risk sending inefficient price signals to customers in some regions of our network, which could:

- exacerbate peak demand in those regions;
- increase our forward looking costs; and

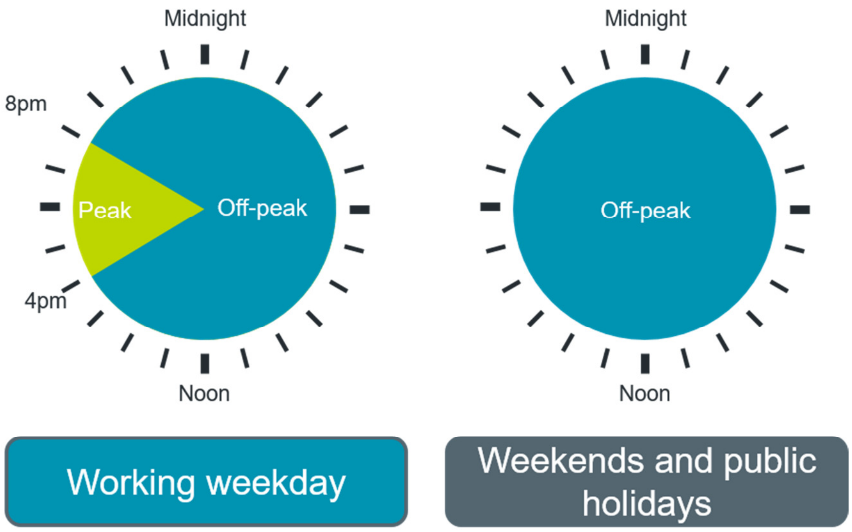
- ultimately, be to the detriment of the long term interests of consumers.

It is relevant at this point to note that moving to locational based charges would add considerable cost and complexity to the billing system and could have marked distributional implications in the absence of extensive supporting analyses and a targeted engagement process. Absent a more detailed analysis of whether a sharper price signal in those locations could potentially lower future investment costs, we are not proposing to consider locational charges at this time.

Finally, our analysis of location-specific demand that is driving our costs (at distribution zone-substations that are approaching capacity) confirms that a peak charging window of 4pm to 8pm aligns with the timing of peak demand in those locations.

On this basis, we propose the charging windows presented in Figure 13 below, as previously discussed at the start of this section. These seasonal charging windows will ensure that we provide efficient LRMC-based price signals at the times of greatest utilisation on our network, consistent with the network pricing principles.

Figure 13 - Our proposed charging windows



We will continue to monitor the timing of peak demand throughout the next regulatory period to ensure we identify any scope to further improve the efficiency of our time of use tariffs.

7.4 Revenue is between stand-alone and avoidable cost for each tariff class

Clause 6.18.5 (e) of the Rules sets the bounds within which our tariffs must be set. For each tariff class, our tariffs must be set at a level such that the revenue we expect to recover from customers lies between:

- the stand-alone cost of serving those customers who belong to that tariff class (the upper bound) and
- the avoidable cost of not serving those customers (the lower bound).

The stand-alone cost of serving a group of customers is the total cost required to serve those customers alone, i.e., were we to build the network anew, removing all other customers from the network. Setting the upper bound at this level ensures that customers that belong to any given tariff class do not pay more as a result of the provision of services to other customers.

The avoidable cost of serving a group of customers is the reduction in cost that could be achieved if those customers were no longer served, i.e., the reduction in cost associated with a reduction in output that was previously provided to that class of customer. Setting the lower bound at this level ensures customers must face a price no lower than the average cost that could be avoided by not supplying them.

Estimating the stand-alone and avoidable costs for each tariff class is an inherently hypothetical exercise. Networks neither routinely assess the cost reductions that might result from disconnecting large groups of customers, nor estimate the cost to supply those customers under the assumption that the remainder of their customer base no longer exists.

In the absence of these type of detailed studies, it is necessary to adopt an approach to estimating stand-alone and avoidable cost that comprises various assumptions, with a strong rationale for the adoption of each.

Endeavour Energy's approach begins by classifying each of our network cost categories on the basis of the following two dimensions:

- whether costs are direct or **indirect** – the framework assumes that a cost category is either:
  - 'direct', meaning that the cost can be attributed to a specific group of users and would not be incurred but for those users (e.g., metering is directly attributable to individual customers), or
  - 'indirect', meaning that the cost is common to multiple groups of users (e.g., operational expenditure costs such as the cost of equity raising cannot be attributed to specific customers or customer groups).
- whether costs are **scalable** or **non-scalable** – the framework assumes that a cost category is either:
  - 'scalable', meaning the cost tends to increase in proportion to the scale at which the service is provided (e.g., maintenance and repair costs are considered scalable as they are likely to be highly dependent on the physical size of the network), or
  - 'non-scalable', meaning the cost is independent of the scale at which the service is provided (e.g., equity raising costs are likely to be relatively independent of network characteristics such as the number of customers or maximum demand).

Endeavour Energy has calculated avoidable cost for each of its tariff classes as the sum of all direct costs multiplied by some weight, which represents the proportion of direct costs that are attributable to that tariff class.

Endeavour Energy's current weights are derived from the estimated value of the assets at each voltage level. Our asset value weights, and the resultant estimates of avoidable cost for each tariff class is set out in Appendix 5.

Endeavour Energy has calculated stand-alone cost for each tariff class by taking the avoidable cost for that tariff class and adding to it:

- all non-scalable indirect costs we incur in operating the network; and
- a proportion of our scalable, indirect costs that can be attributed to that tariff class.

Endeavour Energy's estimates of stand-alone cost are also set out in Appendix 5.

7.5 Tariffs reflect long-run marginal cost and allow for recovery of costs

Clause 6.18.5(f) of the Rules requires that each tariff be based on the long run marginal cost (LRMC) of providing services to those customers assigned to that tariff. There are a number of methods that can be used to estimate the LRMC of supplying specific groups of customers. When determining the method of calculating LRMC and the manner in which it is to be applied, distributors must have regard to:

- the costs and benefits associated with calculating, implementing and applying their proposed method;
- 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
- 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.

We explain in detail our methodology for estimating LRMC in Appendix 6.

Clause 6.18.5(g) allows distributors to set charges that depart from LRMC to the extent that they reflect ‘efficient’ costs and enable the distributor to recover expected revenue for the relevant services in accordance with their distribution determination. However, this must be done in a way that minimises distortions to the price signals for efficient usage that would result from tariffs that are set purely by reference to LRMC.

The effect of clause 6.18.5(g) is to allow distributors to recover their residual costs, which are the fixed costs of operating the network, as well as other costs that they currently pass-through to consumers. However, these costs are required to be allocated between customers in a way that promotes efficient use of the network.

We set out our approach to estimating LRMC, allocating residual costs and passing-through other costs in the sections below.

Estimating LRMC

The LRMC of our network is the cost of supplying one more unit of demand during the system peak.

We have estimated the LRMC of supplying each tariff class using an average incremental cost approach.

Under this approach, the LRMC of network services is estimated as the average change in projected operating and capital expenditure attributable to future increases in demand, ie, it averages the total cost of supplying new growth in demand over that growth in demand.

In practice, under this approach LRMC is estimated by:

- projecting future operating and capital costs attributable to expected increases in demand;
- forecasting future load growth for the relevant network asset (or assets); and then
- dividing the present value of projected costs by the present value of expected increases in demand.

Details of our estimates of LRMC and how these estimates have been converted into charging parameters for each tariff class are set out in Appendix 6.

7.6 Treatment of residual costs

Clause 6.18.5(g) allows for a distributor to recover its residual costs, which are included in its expected revenue allowance.

However, it establishes constraints on the recovery of these costs in that:

- the revenue expected to be recovered from each tariff must reflect the total efficient cost[15] of serving the customers assigned to each tariff; and
- the revenue expected to be recovered from each tariff must minimise distortions to the price signals for efficient usage that would result from tariffs that reflect LRMC.

The requirement that a distributor recovers revenues from each tariff in a manner that minimises distortions for efficient use of the network has implications for:

- the manner in which residual costs are recovered from each tariff, i.e., from the different charging parameters that make up each tariff; and
- the manner in which residual costs are recovered from, or allocated to, different tariffs.

Theoretically, it is most efficient for us to recover from our customers the residual costs we incur exclusively from the fixed charge tariff component because these charges are independent of a customer's usage decisions and therefore minimise the distortion to the LRMC-based price signals that promote efficient usage of our network service.

When a customer's usage charges (either in the form of charges for energy or demand) are set equal to LRMC, the marginal cost to the customer is equal to the marginal cost to the network, which promotes efficiency.

We explain our approach and the reasons for that approach to allocating residual costs in Appendix 7.

In essence, our allocation is guided by three considerations, or principles, i.e.:

- for tariffs where customers have no alternative tariff, or where the structure of alternative tariffs provides the same strength signals for efficient usage, there is no 'hard and fast' rule as to how they should be allocated, so long as the allocation does not violate the customer impact principle;
- for tariffs where a customer can switch to a tariff with a different strength price signal, residual costs should be assigned so as to encourage customers to shift to tariffs that have the most efficient price signal. Put another way, residual costs should be allocated to tariffs so that customers on more efficient tariffs pay a smaller quantum of residual costs; and
- over time charging parameters will need to be rebalanced to ensure that the shifting of customers between tariffs:
    - does not lead to under- or over-recovery of revenue; and
    - does not result in unacceptable bill shock.

Details of how we allocate residual costs are set out in Appendix 7.

7.6.1 Pass through of other costs

Endeavour Energy passes-through a number of costs that we incur in our tariffs including transmission costs and Climate Change Fund jurisdictional scheme costs.

Our approach to the pass-through of these costs is set out in detail in Appendix 8.

[15] We take this to mean the costs necessary to provide the service to each customer, including allocated operating costs and a return on and of the regulated asset base as allocated to the provision of the service to those customers.

7.7 Tariffs mitigate impact on customers

Endeavour Energy considers customer impact to be an upmost priority at this stage of transitioning to efficient pricing. Our proposed tariffs are constructed in accordance to clause 6.18.5(h) of the Rules that requires distributors to consider and limit customer impacts from year to year

A key challenge in this TSS involved managing any potential customer bill impacts arising from a more cost reflective price level for our demand charges. In essence, we considered two options, i.e.:

- apply full cost-reflective demand pricing from 1 July 2019; or
- implement demand framework from 1 July 2019 with an initial low demand tariff and increase this parameter over time.

Endeavour Energy has opted for the second option (the transitional demand tariff) but has also added an opt-in cost reflective pricing option for consumers.

We present an analysis of the customer impacts arising from our proposal in Appendix 10.

Appendix 1: Glossary

Term	Definition
AEMC	Australian Energy Market Commission
AER	Australian Energy Regulator
AIC	Average incremental cost
ASP	Accredited service provider
DBT	Declining block tariff
DNSP	Distribution network service provider
EWON	Energy and Water Ombudsman NSW
GWh	Gigawatt hour
HV	High voltage
IBT	Inclining block tariff
kV	Kilovolt
kVA	Kilovolt-ampere
kW	Kilowatt
kWh	Kilowatt hour
LRMC	Long run marginal cost
LV	Low voltage
NEM	National Electricity Market
NER or the Rules	National Electricity Rules
NUOS	Network Use of System
MVA	Megavolt-ampere
MW	Megawatt
MWh	Megawatt hour
PTR	Peak time rebate
SBS	NSW Solar Bonus Scheme
ST	Subtransmission voltage
TOU	Time of use
TSES	Tariff structure explanatory statement
TSS	Tariff structure statement

Appendix 2: Allocation of customers to tariff classes

Assignment of existing customers to tariff classes at the commencement of the next regulatory control period

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

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

2. If, after 1 July 2019, Endeavour Energy becomes aware that a person will become a customer of Endeavour Energy, then Endeavour Energy will determine the tariff class to which the new customer will be assigned.

3. In determining the tariff class to which a customer or potential customer will be assigned, or reassigned, in accordance with paragraph 2 or 5, Endeavour Energy will take into account one or more of the following factors:
   a) the nature and extent of the customer's usage;
   b) the nature of the customer's connection to the network; and
   c) whether remotely–read interval metering or other similar metering technology has been installed at the customer's premises as a result of a regulatory obligation or requirement.

4. In addition to the requirements under paragraph 3, Endeavour Energy, when assigning or reassigning a customer to a tariff class, will ensure the following:
   a) that customers with similar connection and usage profiles are treated equally;
   b) that customers which have micro–generation facilities are not treated less favourably than customers with similar load profiles without such facilities; and
   c) the national pricing objective and the distribution pricing principles which direct that tariffs charged by a distributor for direct control services should reflect the distributor's efficient costs of providing these services to the customer.

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

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

Notification of proposed assignments and reassignments

6. Endeavour Energy will notify the customer's retailer in writing of the tariff class to which the customer has been assigned or reassigned, prior to the assignment or reassignment occurring.

7. A notice under paragraph 6 above must include advice informing the customer's retailer that they may request further information from Endeavour Energy and that the customer's retailer may object to the proposed reassignment. This notice must specifically include reference to Endeavour Energy's published procedures for customer complaints, appeals and resolution.

8. If the objection is not resolved to the satisfaction of the customer's retailer under the Endeavour Energy's internal review system or the Energy and Water Ombudsman NSW (EWON), then the retail customer is entitled to seek a decision of the AER via the dispute resolution process available under Part 10 of the NEL.

9. If, in response to a notice issued in accordance with paragraph 7 above, Endeavour Energy receives a request for further information from a customer's retailer, then it must provide such

information within a reasonable timeframe. If Endeavour Energy reasonably claims confidentiality over any of the information requested by the customer's retailer, then it is not required to provide that information to the retailer or retail customer. If the customer's retailer disagrees with such confidentiality claims, it may have resort to the dispute resolution procedures referred to in paragraph 7 above (as modified for a confidentiality dispute).

10. If, in response to a notice issued in accordance with paragraph 7 above, a customer's retailer makes an objection to Endeavour Energy about the proposed assignment or reassignment, Endeavour Energy must reconsider the proposed assignment or reassignment. In doing so Endeavour Energy must take into consideration the factors in paragraphs 3 and 4 above, and notify the customer's retailer in writing of its decision and the reasons for that decision.

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

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

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

Appendix 3: Proposed tariff structures – standard control services

Endeavour Energy's proposed tariff structures for its Standard Control Services are set out in the sections below.

Our proposed charges for the regulatory control period are set out in Appendix A9.

1. Small low voltage tariff class

The charging parameters for the proposed tariffs for our low voltage customers in this tariff class are set out in Table 8 below.

Table 8 - Charging parameters for the small low voltage tariff class

Tariff type	Components	Measurement	Charging parameter[16]
Residential Flat Tariff	Fixed	c/day	Access charge reflecting a fixed amount per day.
	Energy	c/kWh	Charge applied to all energy consumption.
Residential Transitional Demand	Fixed	c/day	Access charge reflecting a fixed amount per day.
	Energy	c/kWh	Charge applied to all energy consumption.
	High-season Demand	$/kW/month	Charge applied to maximum energy demand between 16:00 to 20:00 on business days. High-season includes the months November to March inclusive.
	Low-season Demand	$/kW/month	Charge applied to maximum energy demand between 16:00 to 20:00 on business days. Low-season includes the months April to October inclusive.
Residential Demand	Fixed	c/day	Access charge reflecting a fixed amount per day.
	Energy	c/kWh	Charge applied to all energy consumption.
	High-season Demand	$/kW/month	Charge applied to maximum energy demand between 16:00 to 20:00 on business days. High-season includes the months November to March inclusive.
	Low-season Demand	$/kW/month	Charge applied to maximum energy demand between 16:00 to 20:00 on business days. Low-season includes the months April to October inclusive.

[16] Endeavour Energy has displayed block tariff consumption thresholds on a MWh per annum basis. In practice, this annualised consumption threshold will be calculated on a pro-rata basis corresponding to the billing period.

Tariff type	Components	Measurement	Charging parameter[16]
Residential STOU	Fixed	c/day	Access charge reflecting a fixed amount per day.
	High-season Peak Energy	c/kWh	Charge applied to energy consumed between 16:00 to 20:00 on business days. High-season includes the months November to March inclusive.
	Low-season Peak Energy	c/kWh	Charge applied to energy consumed between 16:00 to 20:00 on business days. Low-season includes the months April to October inclusive.
	Off Peak Energy	c/kWh	Charge applied to energy consumed at all other times.
Obsolete Residential TOU (closed to new entrants)	Fixed	c/day	Access charge reflecting a fixed amount per day.
	Peak Energy	c/kWh	Charge applied to energy consumed between 13:00 and 20:00 on business days.
	Shoulder Energy	c/kWh	Charge applied to energy consumed between 07:00 to 13:00 and 20:00 to 22:00 on business days
	Off Peak Energy	c/kWh	Charge applied to energy consumed at all other times.
General Supply Block Tariff	Fixed	c/day	Access charge reflecting a fixed amount per day.
	Energy Block 1	c/kWh	Charge applied to energy consumption up to and including 120 MWh per annum.
	Energy Block 2	c/kWh	Charge applied to energy consumption above 120 MWh per annum.
General Supply Transitional Demand	Fixed	c/day	Access charge reflecting a fixed amount per day.
	Energy	c/kWh	Charge applied to all energy consumption.
	High-season Demand	$/kW/month	Charge applied to maximum energy demand between 16:00 to 20:00 on business days. High-season includes the months November to March inclusive.
	Low-season Demand	$/kW/month	Charge applied to maximum energy demand between 16:00 to 20:00 on business days. Low-season includes the months April to October inclusive.

Tariff type	Components	Measurement	Charging parameter[16]
General Supply Demand	Fixed	c/day	Access charge reflecting a fixed amount per day.
	Energy	c/kWh	Charge applied to all energy consumption.
	High-season Demand	$/kW/month	Charge applied to maximum energy demand between 16:00 to 20:00 on business days. High-season includes the months November to March inclusive.
	Low-season Demand	$/kW/month	Charge applied to maximum energy demand between 16:00 to 20:00 on business days. Low-season includes the months April to October inclusive.
General Supply STOU	Fixed	c/day	Access charge reflecting a fixed amount per day.
	High-season Peak Energy	c/kWh	Charge applied to energy consumed between 16:00 to 20:00 on business days. High-season includes the months November to March inclusive.
	Low-season Peak Energy	c/kWh	Charge applied to energy consumed between 16:00 to 20:00 on business days. Low-season includes the months April to October inclusive.
	Off Peak Energy	c/kWh	Charge applied to energy consumed at all other times.
Obsolete General Supply TOU (closed to new entrants)	Fixed	c/day	Access charge reflecting a fixed amount per day.
	Peak Energy	c/kWh	Charge applied to energy consumed between 13:00 and 20:00 on business days.
	Shoulder Energy	c/kWh	Charge applied to energy consumed between 07:00 to 13:00 and 20:00 to 22:00 on business days
	Off Peak Energy	c/kWh	Charge applied to energy consumed at all other times.
Controlled Load 1	Fixed	c/day	Access charge reflecting a fixed amount per day.
	Energy	c/kWh	Charge applied to controlled energy consumption where energy consumption is controlled by our equipment so that supply may not be available between 07:00 and 22:00.

Tariff type	Components	Measurement	Charging parameter[16]
Controlled Load 2	Fixed	c/day	Access charge reflecting a fixed amount per day.
	Energy	c/kWh	Charge applied to controlled energy consumption where supply is available for restricted periods not exceeding a total of 17 hours in any period of 24 hours.

2. Large low voltage tariff class

The charging parameters for the proposed tariffs for our low voltage customers in this tariff class are set out in Table 9 below.

Table 9 - Charging parameters for the large low voltage tariff class

Tariff Type	Components	Measurement	Charging Parameter
LV Demand	Fixed	c/day	Access charge reflecting a fixed amount per day.
	High-season Peak Energy	c/kWh	Charge applied to energy consumed between 16:00 to 20:00 on business days. High-season includes the months November to March inclusive.
	Low-season Peak Energy	c/kWh	Charge applied to energy consumed between 16:00 to 20:00 on business days. Low-season includes the months April to October inclusive.
	Off Peak Energy	c/kWh	Charge applied to all energy consumed at all other times.
	High-season Demand	$/kVA/month	Charge applied to maximum energy demand between 16:00 to 20:00 on business days. High-season includes the months November to March inclusive.
	Low-season Demand	$/kVA/month	Charge applied to maximum energy demand between 16:00 to 20:00 on business days. Low-season includes the months April to October inclusive.
LV Energy Transition Tariff	Fixed	c/day	Access charge reflecting a fixed amount per day.
	High-season Peak Energy	c/kWh	Charge applied to energy consumed between 16:00 to 20:00 on business days. High-season includes the months November to March inclusive.
	Low-season Peak Energy	c/kWh	Charge applied to energy consumed between 16:00 to 20:00 on business days. Low-season includes the months April to October inclusive.
	Off Peak Energy	c/kWh	Charge applied to energy consumed at all other times.

3. High voltage demand tariff class

The charging parameters for the proposed tariffs for our high voltage demand customers are set out in Table 10 below.

Table 10 - Charging parameters for the high voltage demand tariff class

Tariff type	Components	Measurement	Charging parameter
HV Demand	Fixed	c/day	Access charge reflecting a fixed amount per day.
	High-season Peak Energy	c/kWh	Charge applied to energy consumed between 16:00 to 20:00 on business days. High-season includes the months November to March inclusive.
	Low-season Peak Energy	c/kWh	Charge applied to energy consumed between 16:00 to 20:00 on business days. Low-season includes the months April to October inclusive.
	Off Peak Energy	c/kWh	Charge applied to energy consumed at all other times.
	High-season Demand	$/kVA/month	Charge applied to maximum energy demand between 16:00 to 20:00 on business days. High-season includes the months November to March inclusive.
	Low-season Demand	$/kVA/month	Charge applied to maximum energy demand between 16:00 to 20:00 on business days. Low-season includes the months April to October inclusive.
Individually Calculated HV Demand	As per the HV Demand tariff		

4. Subtransmission voltage demand tariff class

The charging parameters for the proposed tariffs for our subtransmission voltage are set out in Table 11 below.

Table 11 - Charging parameters for the subtransmission voltage demand tariff class

Tariff type	Components	Measurement	Charging parameter
ST Demand	Fixed	c/day	Access charge reflecting a fixed amount per day.
	High-season Peak Energy	c/kWh	Charge applied to energy consumed between 16:00 to 20:00 on business days. High-season includes the months November to March inclusive.
	Low-season Peak Energy	c/kWh	Charge applied to energy consumed between 16:00 to 20:00 on business days. Low-season includes the months April to October inclusive.
	Off Peak Energy	c/kWh	Charge applied to energy consumed at all other times.
	High-season Demand	$/kVA/month	Charge applied to maximum energy demand between 16:00 to 20:00 on business days. High-season includes the months November to March inclusive.
	Low-season Demand	$/kVA/month	Charge applied to maximum energy demand between 16:00 to 20:00 on business days. Low-season includes the months April to October inclusive.
Individually Calculated ST Demand	As per the ST Demand tariff		

5. Inter-distributor transfer tariff class

The charging parameters for the proposed tariffs for our inter-distributor transfer customers are set out in Table 12 below.

Table 12 - Charging parameters for the inter-distributer transfer tariff class

Tariff type	Components	Measurement	Charging parameter
Individually Calculated Demand	Fixed	c/day	Access charge reflecting a fixed amount per day.
	High-season Peak Energy	c/kWh	Charge applied to energy consumed between 16:00 to 20:00 on business days. High-season includes the months November to March inclusive.
	Low-season Peak Energy	c/kWh	Charge applied to energy consumed between 16:00 to 20:00 on business days. Low-season includes the months April to October inclusive.
	Off Peak Energy	c/kWh	Charge applied to energy consumed at all other times.
	High-season Demand	$/kVA/month	Charge applied to maximum energy demand between 16:00 to 20:00 on business days. High-season includes the months November to March inclusive.
	Low-season Demand	$/kVA/month	Charge applied to maximum energy demand between 16:00 to 20:00 on business days. Low-season includes the months April to October inclusive.

6. Unmetered supply tariff class

The charging parameters for the proposed tariffs for our unmetered supply customers are set out in Table 13 below.

Table 13 - Charging parameters for the unmetered supply tariff class

Tariff type	Components	Measurement	Charging parameter
Unmetered Energy Tariff	Energy	c/kWh	Charge applied to all energy consumption.

Appendix 4: Proposed tariff structures – alternative control services

This Appendix sets out Endeavour Energy's proposed tariff structures for its ancillary network services, metering services and public lighting services.

1. Ancillary network services

Ancillary service prices are provided to customers as either of the following:

- **Fee based services:** the work involved in some ancillary service activities are relatively fixed and are charged on a per activity basis. Fees are derived from the relevant labour rates and average time required to perform the task and are charged irrespective of the actual time taken to complete the activity; and
- **Quoted services:** costs for some ancillary service activities may vary considerably between jobs. This is often the case for one-off activities that are specific to a particular customer's request. For quoted services, charges are levied on a time and materials basis. Prior to commencing work, customers are informed of the per hour cost with the final total charge payable dependent on the time taken to complete the respective activity.

For the 2019-24 period, we propose to provide most of the ancillary service activities that were provided to customers in the current regulatory period. We have also proposed to provide several new activities to reflect recent regulatory and service classification changes that require us to provide them to our customers.

We propose the following forms of control for ancillary network services over the 2019-24 regulatory period consistent with the AER's F&A decision, i.e.:

- a schedule of fixed prices for ancillary network services for the first year of the regulatory period; and
- a price path for the remaining years of the regulatory control period, based on the CPI-X methodology contained in the submitted ancillary network services model.

Further detail on our ancillary network services proposal can be found in chapter 2.5 of our Revised Regulatory Proposal.

Our proposed charges for our ancillary network services for the 2019-24 period are set out in Attachment 0.17 of our Revised Regulatory Proposal.

2. Metering

Our proposed pricing approach is the same as that which applied for the 2014-19 period for the same reasons. To summarise, we have split metering services between primary and secondary categories. The latter are metering services that are in addition to the basic network service most customers receive, such as off-peak hot water or solar PV meter services. These additional services result in only marginally higher overall costs and therefore attract a lower incremental charge.

This means that a customer will pay a greater amount for their first metering service as this creates the majority of costs we incur as their meter provider. This approach also ensures that customers who have more metering services than a basic accumulation service will pay more to reflect the additional services being provided. We consider this balances the need for cost reflectivity and fairness. Our approach involves the following:

- **Existing metering assets:** we will seek to recover the existing capital costs for Type 5 and 6 meters during the course of the 2019-24 period. The collection of existing meter costs will be on a per-customer basis to avoid penalising customers for past decisions; and
- **Opex:** ongoing costs such as maintenance, meter reading, meter testing and data services will be recovered via a cents per day charge. The prices for ongoing opex have been developed on a per-service basis. This means that each unique data stream will attract a price. For example, a basic metering charge and an off-peak metering charge equates to two data streams and two services.

We propose the following forms of control for metering services over the 2019-24 regulatory period consistent with the AER's F&A decision, i.e.:

- a schedule of fixed prices for metering services for the first year of the regulatory period; and
- a price path for the remaining years of the regulatory control period, based on the CPI-X methodology contained in the submitted metering services model.

Further detail on our metering proposal can be found in chapter 2.5 of our Revised Regulatory Proposal.

Our proposed charges for our metering services for the 2019-24 period are set out in Attachment 0.18 of our Revised Regulatory Proposal.

3. Public lighting

We propose to continue applying the current tariff structures and component based pricing over the next regulatory period, based on supportive feedback provided by councils in our network area on the current structures. The tariff classes are broken down into two key subgroups, tariffs for assets installed before 8 August 2009 and those after this date:[17]

- **Tariff class 1:** is an aggregate capital recovery and maintenance tariff. This applies where the asset was initially funded by us and was included as part of the RAB determined by IPART prior to 8 August 2009. Capital cost recovery built into this tariff class will trend in line with the residual RAB value reducing over time and historical price escalation constraints. Assets priced under tariff class 1 may sometimes also be referred to as legacy assets. No new public lighting installations are covered by this tariff class;
- **Tariff class 2:** is a maintenance cost recovery only tariff. This applies to assets where we did not fund the initial construction which occurred prior to 8 August 2009. As we did not fund the construction we are not entitled to any capital recovery charges for these assets. Similarly with tariff class 1, assets priced under tariff class 2 may sometimes also be referred to as legacy assets. No new public lighting installations are covered by this tariff class;
- **Tariff class 3:** is an aggregate capital recovery and maintenance tariff similar to tariff class 1, however this tariff class is priced using an annuity approach and only applies to assets installed after 8 August 2009. Unlike tariff class 1 there is no RAB value driving variable prices over time and is specific to the asset installed;
- **Tariff class 4:** is a two part tariff; the first element is a maintenance cost recovery only charge similar to tariff class 2. This applies to assets where we did not fund their initial construction which occurred after 8 August 2009. As we did not fund the construction we are not entitled to any capital recovery charges for these assets. However, we are required to pay income tax on assets gifted to us in this manner. The second element of tariff class 4 is a tax cost recovery charge that is paid through an annual amount over the life of an asset that is gifted to us by our customers after 8 August 2009; and
- **Tariff class 5:** is a pure capital recovery tariff that is paid in a lump sum at the time of agreeing to replace an asset before the end of its useful life. This tariff class does not have specified prices but rather a specified formula for calculating the residual unrecovered capital and tax costs when a customer requests an early replacement of assets paid for by us.

We propose the following forms of control for public lighting services over the 2019-24 regulatory period consistent with the AER's F&A decision, i.e.:

- a schedule of fixed prices for public lighting services for the first year of the regulatory period; and
- a price path for the remaining years of the regulatory control period, based on the CPI-X methodology contained in the submitted public lighting model.

Further detail on our public lighting proposal can be found in chapter 2.5 of our Revised Regulatory Proposal.

Our proposed charges for our public lighting services for the 2019-24 period are set out in Attachment 0.16 of our Revised Regulatory Proposal.

[17] Even though the AER cut-off date for switchover of charges from legacy rates to annuity rates was 1 July 2009, on demand from its Public Lighting Customers and ASPs, Endeavour Energy agreed to a date of 8 August 2009 to cater for completion of projects that were already under way and to give time for Public Lighting Customers and ASPs to understand the new rates.

4. Security lights (Nightwatch)

Security lighting for private customers is similar to public lighting with installations typically attached to existing distribution network poles and structures. Customers are able to select from a variety of lighting equipment which is mounted on nearby network poles and positioned to provide optimal illumination according to their needs. We operate and maintain these lights which are commonly used by public buildings, sports arenas, shopping centres and car yards.

For the purposes of transitioning this service to regulation by the AER we have proposed a forward looking pricing methodology for security lights similar to that of public lighting tariff 3. Customers are required to pay a one-off installation cost and a monthly rental charge. These charges will vary depending on the type of lighting service requested and length of the contractual period. The ongoing charge will cover the costs of operating, maintaining and replacing the assets as required.

For existing contracted prices negotiated in an unregulated environment we are proposing that these prices be grandfathered as part of the transition to regulated prices.

We propose the following forms of control for ancillary network services over the 2019-24 regulatory period consistent with the AER's F&A decision, i.e.:

- a schedule of fixed prices for ancillary network services for the first year of the regulatory period; and
- a price path for the remaining years of the regulatory control period, based on the CPI-X methodology contained in the submitted ancillary network services model.

Further detail on our security lights (Nightwatch) proposal can be found in chapter 2.5 of our Revised Regulatory Proposal.

Our proposed charges for our security lights (Nightwatch) services for the 2019-24 period are unchanged from the AER's draft decision.

Appendix 5: Estimated stand-alone and avoidable cost

Clause 6.18.5(e) of the Rules requires Endeavour Energy to set tariffs for each tariff class between the avoidable and stand-alone cost of providing services to each class of customers.

Further detail in relation to our estimates of avoidable and stand-alone cost is set out in the section below. It is important to note that the estimates below are illustrative of Endeavour Energy's proposed methodology and will be updated annually to reflect current inputs and assumptions.

Endeavour Energy has not changed its stand-alone and avoidable cost calculation methodology for this TSS period. The AER has accepted this methodology in their draft TSS decision.

1. Avoidable cost

An illustrative example of Endeavour Energy's methodology for the calculation of the avoidable cost of serving customers in each tariff class is set out in Table 14 below.

Table 14 - Asset value weights and resultant estimates of avoidable cost by tariff class, 2019-20 ($m)

Tariff class	Total direct cost	Asset value weight	Avoidable cost per tariff class
Small LV	459	86%	393
Large LV		8%	35
HV Demand		3%	14
ST Demand		3%	12
Inter-Distributor Transfer		1%	3
Unmetered		0%	-

2. Stand-alone cost

Endeavour Energy has calculated stand-alone costs according to the following formula:

$$\text{Stand} - \text{alone Cost}_i = \text{Avoidable Cost}_i + \text{Nonscalable Indirect Costs} + \sum_{j=1}^{n} \beta_{i,j}\text{Scalable Indirect Costs}_j,$$

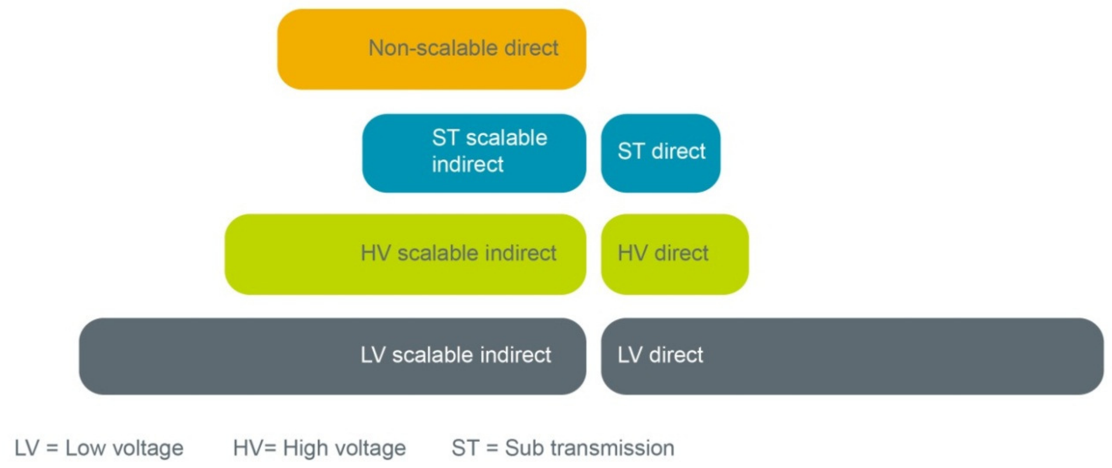
Where:

- i represents each of Endeavour Energy's tariff classes;
- $\text{Stand alone Cost}_i$ is the stand-alone cost to serve customers on tariff class i;
- Avoidable Costs_i is the avoidable cost to serve customers on tariff class i;
- j represents each of Endeavour Energy's scalable indirect cost categories; and
- $\beta_{i,j}$ is the scaling factor (some value between zero and one) applied to cost category j.

Endeavour Energy's current model has derived all scaling factors from the asset values attributable to customers in each tariff class.

Figure 14 illustrates this process applied to each of the three voltage levels in Endeavour Energy's network, ie, subtransmission, high voltage, and low voltage.[18] The figure illustrates the relationship between the different cost components.

Figure 14- Components of stand-alone costs for Endeavour Energy's three voltage levels



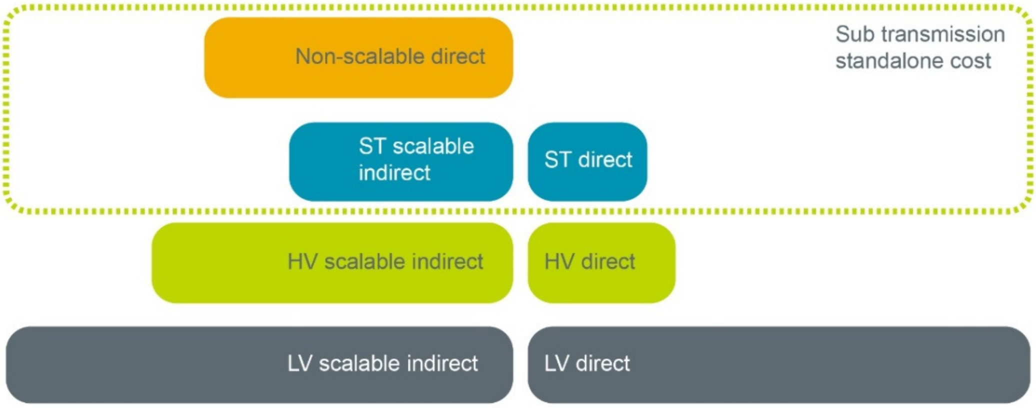
Scalable indirect costs of higher voltage services necessarily feed into the scalable indirect costs of lower voltage services. Put another way, part of the low voltage scalable indirect costs are associated with providing subtransmission and high voltage services, which are necessary precursors to low voltage supply.

Figure 15 shows that stand-alone costs of a particular customer group are calculated to be the sum of:

- non-scalable indirect costs;
- direct costs incurred by that group; and
- scalable indirect costs attributable to that group.

[18] For the purposes of illustration, this figure simplifies Endeavour Energy's tariff classes by the Small LV and Large LV tariff classes, and omitting the Inter-Distributor Transfer and Unmetered tariff classes.

Figure 15 - Framework for calculating stand-alone cost of subtransmission customers



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

Such an approach is predicated on the assumption that current network expenditure is a valid reference point. There is no guarantee that this assumption will always hold.

For example, consider a tariff class consisting only of large industrial customers located at one remote, isolated part of the network. Expenditure to supply these customers via the existing network could potentially well exceed the cost of a new network constructed solely to service these customers alone, say in the form of a small network with energy supplied via a local generator.

In contrast, it seems reasonable to assume that the optimal network to supply all of the customers in the low voltage network – and only those customers, would have similar characteristics to the current network, albeit with a reduction in the scale of investment in the high voltage and subtransmission systems. Given that Endeavour Energy's tariff classes are principally defined with respect to voltage level, we believe this approach is reasonable.

Endeavour Energy's approach yields the estimates of stand-alone cost set out in the table below. We note that low voltage tariff classes have been attributed the highest scalable indirect costs because the majority of our asset value has been attributed to low voltage customers.

Table 15 - Components of stand-alone cost for each tariff class, 2019/20 ($m)

Tariff class	Non-scalable indirect costs	Scalable indirect costs	Avoidable (direct) costs	Stand-alone cost
Small LV	29	390	393	812
Large LV		390	35	454
HV Demand		282	14	330
ST Demand		86	12	129
Inter-Distributor Transfer		86	3	120
Unmetered		390	-	419

Appendix 6: Estimated LRMC

The AER's draft TSS decision accepts our LRMC methodology as proposed in our initial TSS decision. We have updated the LRMC figures below to reflect our revised capex forecast.

The marginal cost of an energised connection is typically expressed in terms of the cost per kW (or cost per kVA) of maximum demand. Put another way, the 'cost of the next unit' is assumed to be the cost of supplying one more unit of demand during the system peak.

1. Our approach to estimating LRMC

The distribution pricing principles in the rules state that:[19]

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…

Long run marginal cost (LRMC) is a forward-looking concept and measures the additional cost incurred as a result of an incremental (or relatively small) increase or decrease in the use of our network, assuming all factors of production are able to be varied. It focuses on forward-looking costs because it is only future costs – not historical costs – that will be affected by changes in the use of our network, ie, only future costs can be saved. For example, Kahn highlights that:[20]

Marginal costs look to the future, not to the past: it is only future costs for which additional production can be causally responsible; it is only future costs that can be saved if that production is not undertaken. …in a dynamic economy, with changing technology as well as changing factor prices, there is every reason to believe that future capital costs per unit of output will not be the same as the capital costs historically incurred installing present capacity.

These comments also illustrate that the cost of new network capacity, and so LRMC, changes through time.

As a matter of principle, setting prices equal to LRMC will promote efficient use and production of electricity network services because:

- it ensures that customers face price signals that reflect the resource cost of providing services, which encourages them to use our network where the benefit they derive exceeds the cost of providing the relevant network service; and
- it signals to us the value our customers place on potential future investments in our network.

1.1 Estimation methodologies

There are two main approaches to practically estimating the LRMC, i.e.:

- the perturbation or 'Turvey' approach; and
- the average incremental cost (AIC) approach.

The perturbation approach involves estimating LRMC equal to the change in forward looking operating and capital costs resulting from a small upward or downward perturbation, or change, in forecast demand. Although the perturbation approach best reflects the theoretical construction of LRMC, its application is administratively burdensome, as compared with the AIC approach, and so DNSPs have to date generally favoured the AIC approach.

The AIC approach involves estimating LRMC equal to the average change in forward-looking costs resulting from the forecast change in demand over a defined period. It is typically applied by:

- forecasting the level of expected demand growth over a defined period;

[19] Rules, clause 6.18.5(f).
[20] Kahn, A, The Economics of Regulation: Principles and Institutions, Massachusetts Institute of Technology, volume 1, p.98

- forecasting the future capital and operating expenditure required to meet that demand forecast; and
- dividing the present value of forecast expenditure by the present value of forecast demand growth.

Put differently, the AIC approach involves estimating LRMC as follows, ie:

$$LRMC = \frac{NPV(growth\ related\ capital\ and\ operating\ costs)}{NPV(additional\ demand\ served)}$$

The AIC approach is generally applied only in circumstances where there is expected demand growth, owing to its implicit focus on forecast demand growth and future growth-related costs. Therefore, the AIC approach needs to be modified if it is to be applied to estimate LRMC in circumstances where demand is declining.

Potential improvements to the AIC approach

In addition to changing through time, LRMC also varies across the different locations that comprise our network, ie, LRMC is likely to be:

- higher in areas where our network is highly utilised; and
- lower in areas where there is excess capacity available.

Despite this locational dimension to LRMC, the application of postage stamp pricing means that a single, network-wide estimate of LRMC is required for pricing purposes. In the past Endeavour and other DNSPs have applied the AIC approach by reference to:

- all future growth-related expenditure; and
- the forecast growth in network demand.

Following the AER's comments in its final decision on our first TSS we considered potential elements of the AIC approach that could be improved, as summarised below.

The potential role of replacement expenditure

The potential for and nature of a causal relationship between demand and the level of replacement expenditure is likely to differ between locations where demand is declining and falling. We consider these two circumstances and the appropriateness of including replacement expenditure in the estimation of LRMC below.

Demand can affect replacement expenditure in areas of declining demand

The AIC approach is generally applied only in circumstances where there is expected demand growth, owing to its implicit focus on forecast demand growth and growth-related costs. However, the concept of LRMC applies equally to an increase or decrease in demand and, as Turvey notes:[21]

Marginal costs between upwards and downwards changes may differ.

It is intuitive that in areas of the network where demand is declining, a reduction in demand may permit the downsizing of an asset upon replacement at the end of its useful life. It follows that the LRMC of a decline in demand would be likely to reflect avoidable replacement expenditure, rather than growth-related costs.

That said, a decision to downsize an asset upon replacement and realise a corresponding cost saving will depend on a range of economic and engineering considerations, including:

- the available asset sizes;
- the quantum of any cost saving arising from downsizing upon replacement; and

[21] Turvey, R., *What are Marginal Costs and How to Estimate them?*, March 2000, p.3.

- the risk and cost associated with having to upsize that asset over its life due to a future increase in demand.

The role of replacement expenditure in locations where demand is growing
Where an asset reaches the end of its useful life and expected demand growth leads to its replacement with a higher-rated asset, the additional expenditure associated with upsizing that asset upon replacement should be classified as a growth-related cost, rather than replacement expenditure. This is consistent with the AER's Expenditure Forecast Assessment Guideline, which explains that:[22]

*Replacement expenditure is the **non-demand driven capex** to replace an asset with its modern equivalent where the asset has reached the end of its economic life. [emphasis added]*

It follows that, provided replacement expenditure is appropriately classified, expenditure classified as 'replacement expenditure' in areas of the network where demand is growing would not be affected by growing demand and so should not be included in the calculation of LRMC.

That said, it is important to review the drivers of expenditure classified as 'replacement expenditure' for planning purposes to identify whether any part of that expenditure is driven by demand, and so should be included in the estimation of LRMC.

A network-wide estimate may overstate LRMC in areas of growing demand
Network demand comprises the sum of demand across all locations that comprise our network, where demand may be expected to grow in some locations and to fall in others. In these circumstances, forecast growth in network demand understates the additional demand served as a result of growth-related expenditure. This is because of the offsetting effect of falling demand at some locations, which lowers the denominator in the AIC calculation and therefore overstates the LRMC of serving additional demand.

By way of example, consider circumstances where $1 of growth-related expenditure is required to serve an additional 3kW of demand at Substation A in Year 1, but demand at Substation B falls by 1kW in that year (with no effect on future costs). In this case, growth related expenditure is $1 and the additional network demand served is $2kW (3kW less kW), ie, the inputs to the AIC calculation (as typically defined) would suggest that $1 of expenditure was required to serve 2kW of additional network demand (3kW minus 1kW). In fact, $1 of expenditure at Substation A was sufficient to serve 3kW of additional demand at substation A and so the inputs to the LRMC calculation for growing Substation A in that year should be expenditure of $1 and additional demand of 3kW.

Our proposed methodology

We applied the average incremental cost approach to estimate the LRMC of providing network services to our customers. However, application of the AIC approach generally has regard only to growth-related expenditure and so disregards the potential for demand to affect the level of replacement expenditure.

Consequently, we undertook detailed discussions with our network planners to inform our understanding of the decision-making process for replacements and, ultimately, to determine the extent to which replacement expenditure should be incorporated into our estimate of LRMC.

These discussions identified that there are two general circumstances in which demand could affect the level of replacement expenditure, i.e.:

- where an increase in demand requires an existing asset nearing the end of its life to be replaced with a larger sized asset – this could happen where demand is growing; [23] and
- where a decrease in demand enables an existing asset nearing the end of its life to be replaced with a smaller sized asset – this could happen where demand is falling.

[22] AER, *Explanatory Statement – Expenditure Forecast Assessment Guideline*, November 2013, p.184.
[23] Consistent with the AER's Expenditure Forecast Assessment Guideline, in this circumstance the cost of the replaced larger sized asset would be split into a replacement expenditure component based on the cost of a like-for-like asset replacement, with the remainder of the cost being allocated to augmentation expenditure.

Since there are two distinctly different ways and circumstances in which demand might affect replacement expenditure, we evaluated them both separately. We did this by estimating LRMC and explicitly considering whether to include replacement expenditure:

- in areas where we expect demand growth over the next ten years; and
- in areas where we expect stable or declining demand over the next ten years.

In addition to enabling the inclusion of demand-affected replacement expenditure, our approach also enabled us to better understand how our future costs vary across our network.

LRMC in areas where demand is growing

To estimate the LRMC in areas where demand is growing, we first identified zone substations at which demand was forecast to grow over the next ten years. We estimated LRMC across these zone substations by reference to the sum of forecast demand at those zone substations only, rather than forecast network demand.

We allocated to these zone substations the relevant site-specific augmentation expenditure and all program augmentation expenditure. We also undertook a detailed review of forecast replacement expenditure to determine whether that expenditure – either in whole or part – is driven by growing demand.

Our review confirmed that all replacement projects for these zone substations involved the replacement of assets on a like-for-like basis, with the exception of the Gerringong zone substation. One of the two 5MVA transformers at the Gerringong zone substation is to be replaced with an existing spare 10MVA transformer, which was previously removed from another zone substation. It follows that the corresponding increase in capacity is not driven by demand but, rather, is the most cost-efficient approach to replacement. We therefore excluded replacement expenditure from our estimation of LRMC for areas in which demand is growing.

This decision reflects that replacement expenditure at zone substations where demand is growing could not be avoided even if demand was to incrementally rise or fall, as compared with our expectations.

It follows that the relevant replacement expenditure forecast was classified consistent with the AER's Expenditure Forecast Assessment Guideline, which explains that:[24]

Replacement expenditure is the non-demand driven capex to replace an asset with its modern equivalent where the asset has reached the end of its economic life.

That said, our focus on better understanding the drivers of network planning decisions highlighted the importance of reviewing in detail the expenditure inputs to our LRMC calculations. To the extent some proportion of a replacement expenditure is driven by demand and not classified as augmentation expenditure in the future, we will include the relevant proportion of replacement expenditure in our estimation of LRMC.

We present our estimates of LRMC in areas of our network where demand is growing in Table 16 below.

[24] AER, *Explanatory Statement – Expenditure Forecast Assessment Guideline*, November 2013, p.184.

Table 16 - LRMC estimates in areas where demand is growing.

Service	LRMC estimate ($/kW pa)
Low Voltage	91.3
High Voltage	8.1
Subtransmission	7.8

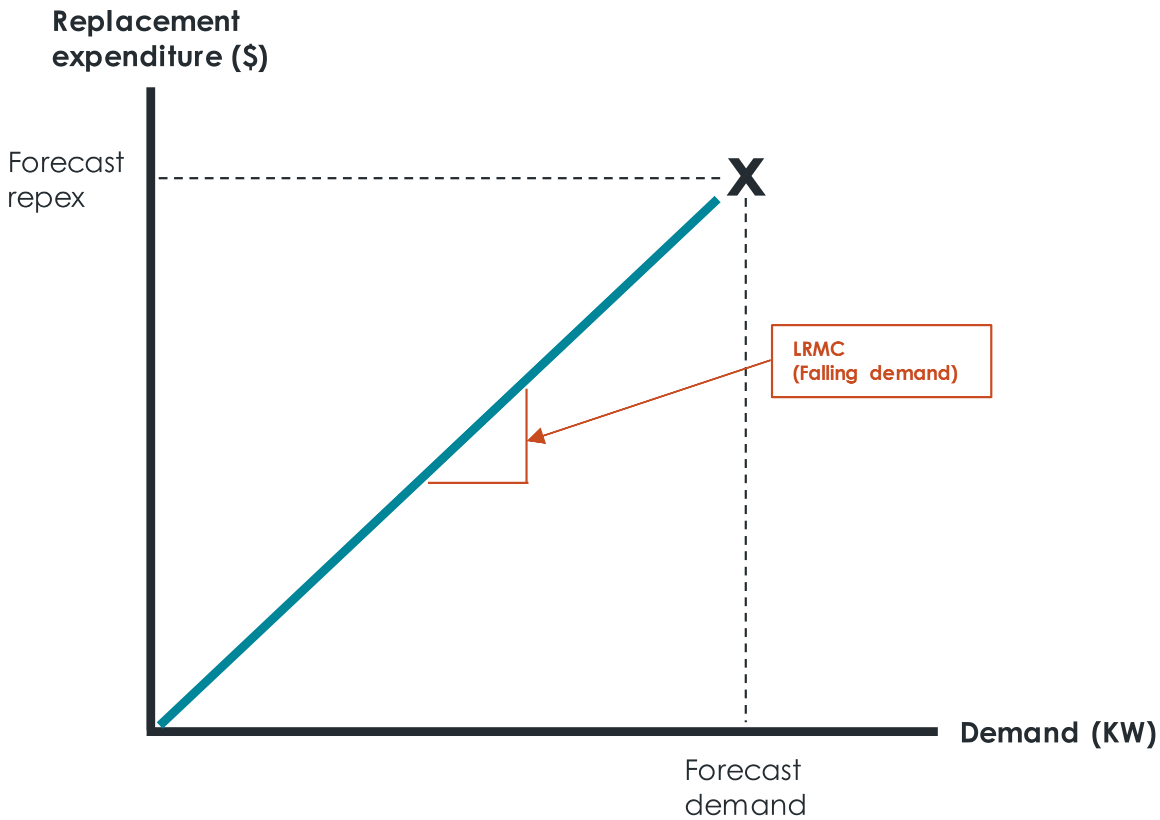
LRMC in areas where demand is stable or falling

Estimating LRMC in areas of our network where demand is forecast to remain stable or to fall necessitated modifications to the AIC approach, i.e., to account for the absence of 'growth related costs' and 'negative' demand growth. As a starting point, we considered circumstances where there existed a linear relationship between demand and replacement expenditure, i.e., such that a ten percent reduction in demand would result in a ten per cent reduction in replacement expenditure. This would mean calculating LRMC as follows, i.e.:

$$LRMC = \frac{NPV(total\ capital\ and\ operating\ replacement\ costs\ for\ relevant\ substations)}{NPV(total\ demand\ at\ the\ relevant\ substations)}$$

We illustrate this potential relationship in Figure 16 below.

Figure 16 - Stylised diagram of potential relationship between demand and replacement expenditure



Our analysis indicates that this 'linear' assumption would lead to an estimate of LRMC equal to $73/kW for the low voltage tariff class. However, our discussions with network planning engineers indicated that an assumed linear relationship would significantly overstate the effect of a fall in demand on replacement expenditure.

First it is relevant to note that, although there exists a theoretical relationship between the extent an asset is used and its useful life, in our experience this relationship is not readily observable in practice. Therefore, incremental changes in demand do not have a material effect on the useful life of an asset, ie, the timing of replacement. However, changes in demand may affect the level of replacement expenditure at the time of replacement.

The non-linear nature of the relationship between demand and replacement expenditure follows from the economic considerations that govern network replacement decisions, namely that the cost savings associated with the potential downsizing of an asset upon replacement:

- are typically low in the context of the total cost of a replacement; and
- are generally insufficient to outweigh the risk that an increase in demand over the asset's useful life (up to 45 years) will necessitate an upgrade that costs significantly more than the cost saving upon downsizing.

This is namely because of the significant economies of scale in the replacement of assets at the end of their useful life, ie, because of the significant role of installation costs in replacement projects. By way of example:

- the cost of a transformer itself is in the order of $1 million to $1.5 million, but the installation cost of replacing a transformer is approximately $2 million to $3 million, ie, a significant proportion of the total cost; and
- the difference in cost between, say, a 25MVA and 35MVA transformer is approximately $300,000.

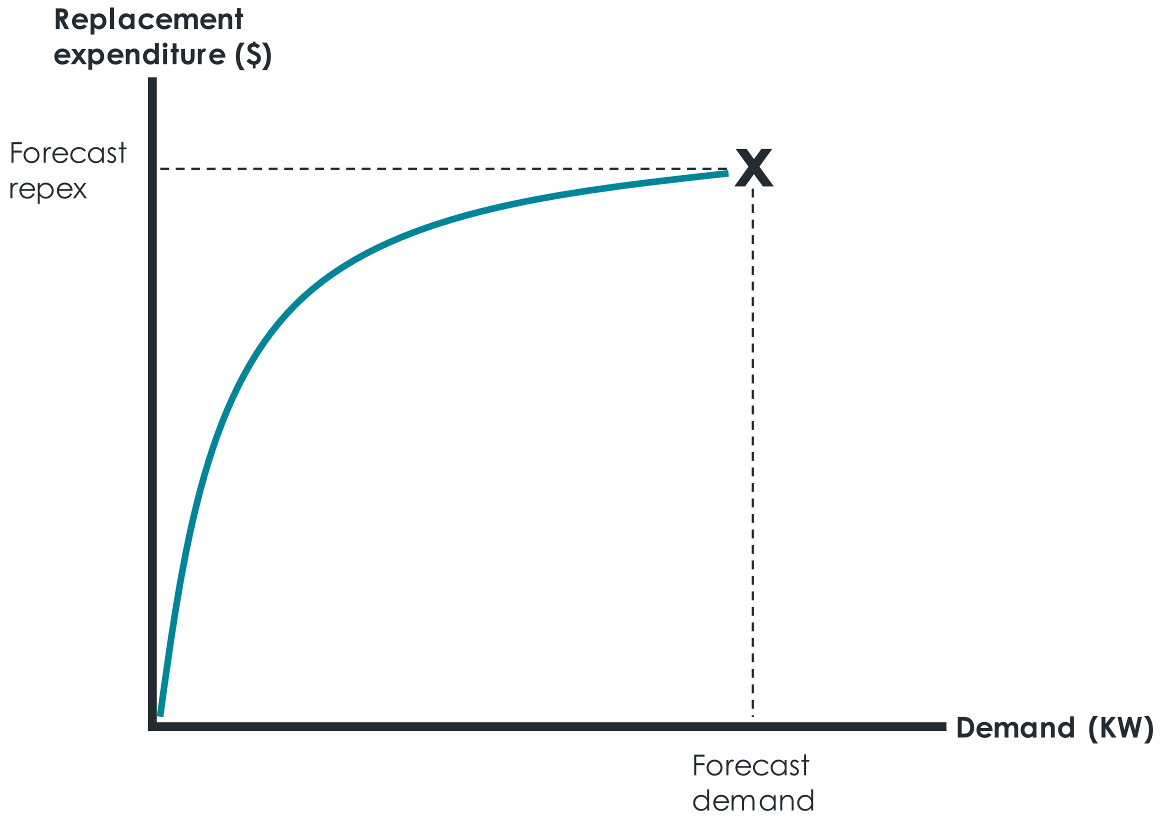
In other words, the cost saving of downsizing an asset upon replacement are generally low in the context of the total replacement cost. Further, the potential cost saving in the short term of downsizing an asset upon replacement must be weighed against the risk that a future increase in demand over the asset's useful life (approximately 40 years) will necessitate further expenditure. Relevantly, the potential future cost of having to increase the rating of an asset that was previously downsized generally significantly outweighs the cost saving in the short term.

For example, in considering options for the renewal of the Marayong zone substation we identified that downsizing its firm capacity from 50MVA to 35MVA upon the replacement of its three existing transformers would give rise to a cost saving of only $0.5 million, but risk further costs of $2.6 million if demand increases in the future.

The scope to downsize an asset upon replacement also depends on the cost efficiencies associated with stocking asset types with the same rating. Further, many of our assets are purchased on international markets, where the available ratings are governed by the requirements in larger countries such as the United States and China. Therefore, there are often large increments in asset sizes available and so a significant and sustained reduction in demand is required before it is economic to downsize an asset.

Against this back-drop, the causal relationship between demand and replacement expenditure is unlikely to be linear and is more likely to reflect the relationship illustrated in Figure 17 below.

Figure 17- Stylised relationship between demand and replacement expenditure



The replacement project at the Marayong zone substation well illustrates this relationship, particularly since approximately 70 per cent of our forecast replacement costs relate to zone substations.

Box 1: Case study of replacement expenditure in Marayong zone substation

The Marayong zone substation in Blacktown comprises three 25MVA transformers (50MVA firm capacity) that are approaching the end of their useful life (less than five years remaining). One of those transformers requires replacement in the short term and, given the economies of scale in replacement projects, it is efficient to replace the other two transformers and the other assets that comprise the zone substation at the same time. It is relevant to note that demand at the Marayong zone substation is forecast to be stable at approximately 40MVA over the next ten years.

We went to market for non-network options that would enable a downsizing of the Marayong zone substation from the current firm rating of 50MVA. As mentioned earlier, we determined that the cost saving associated with downsizing firm capacity to 35MVA was not efficient due to the corresponding risk of a much higher cost in the long run.

However, a non-network option that enables a demand reduction of 13.5MVA would permit a downsizing of firm capacity to 25MVA and reduce the cost of the replacement from $18.8 million to $17.4 million, ie, a cost saving of $1.4 million.

Put differently, a 34 per cent reduction in demand[25] would be sufficient to reduce the replacement cost by only 7.9 per cent.[26] In other words, on average every five per cent reduction in demand resulted in a one per cent replacement expenditure saving.

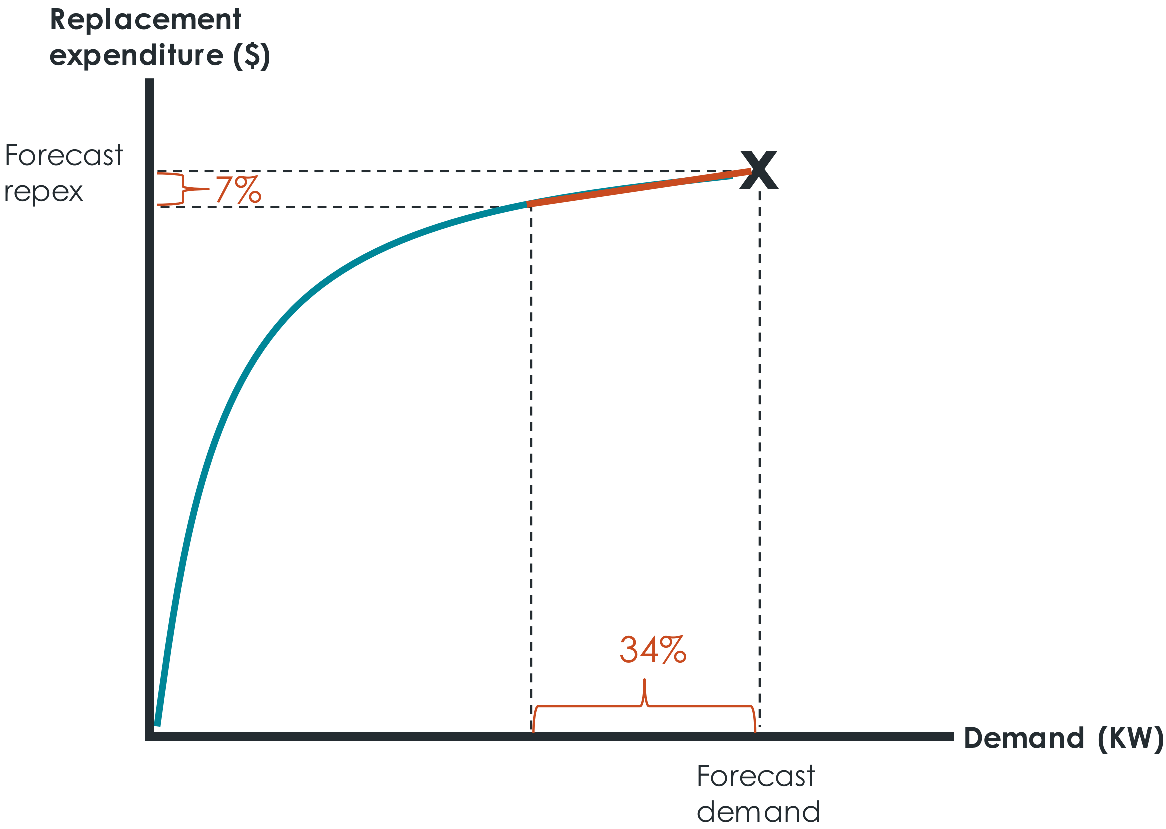
This current example of a replacement project illustrates:

- that the cost saving arising from downsizing an asset is relatively low, as compared with the total cost of the replacement; and
- a significant, sustained reduction in demand (34 per cent in this case) would be required to make downsizing economically efficient.

Following detailed discussions with network planners we consider that it is appropriate to apply the observed, five to one relationship between demand and replacement cost savings at the Marayong zone substation to approximate avoidable replacement expenditure in this TSS, as shown in the figure below. We consider this to be an appropriate, albeit highly conservative, approach since a demand reduction of close to 34 per cent would be very unlikely. In other words, this approach may still overstate the relationship between demand and replacement expenditure because a smaller reduction in demand would correspond to a flatter section of the stylised curve in Figure 18 below.

[25] A reduction in demand from 40MVA to 25MVA, in addition to a 1.5MVA load transfer. A 37 per cent reduction would be required without the load transfer.
[26] Calculated equal to 1,383,000 divided by 18,822,000.

Figure 18 - Assumed relationship between demand and replacement expenditure



Practically, we estimate LRMC in areas of falling demand as follows, i.e.:

$$LRMC = \frac{NPV(total\ capital\ and\ operating\ replacement\ costs\ for\ relevant\ substations)}{NPV(total\ demand\ at\ the\ relevant\ substations)} \times \frac{7}{34}$$

We present our estimates of LRMC in areas of falling demand in Table 17 below, under both an assumed linear relationship and what we consider to be a more appropriate assumption, as explained above.

Table 17 - LRMC estimates in areas where demand is stable or falling

Service	LRMC – best estimate ($/kW pa)	LRMC – hypothetical linear relationship ($/kW pa)
Low Voltage	11.8	57.9
High Voltage	0.8	3.9
Subtransmission	0.6	2.7

Deriving a single LRMC estimate for each tariff class

Our analysis shows that LRMC in areas of our network where demand is growing is significantly higher than those areas where demand is falling. For example, we estimate that for the low voltage tariff class LRMC is:

- equal to $91/kW in areas of growing demand; and
- equal to $12/kW in areas of declining demand.

In essence, these estimates can be thought of as a disaggregation of the network-wide estimate of LRMC in our first TSS. However, our proposal to apply postage-stamp pricing means that for pricing purposes we must infer from this estimated range a single estimate of LRMC for each tariff class.

Given the apparent diversity in LRMC across our network, this necessarily means that the price signal to some customers will differ from a reasonable estimate of the forward-looking costs that could be practically avoided in each location. The task at hand is therefore how best to minimise this inconsistency, consistent with the national pricing objective and the long-term interest of our customers.

Of particular relevance to this decision, we note that over the next regulatory control period we expect:

- demand in growing areas of our network to increase by approximately 785 MW; and
- demand in declining areas of our network to decrease by less than 30 MW.

Further, it is clear that the future cost-consequences of sending inefficient price signals in growing areas of our network are approximately 9 times greater than those in areas of our network where prices are falling.[27] Specifically, using the low voltage tariff class as an example:

- a lower than LRMC-based peak price in areas of our network where demand is growing may encourage inefficient over-use of our network in those areas and result in $91/kW of additional inefficient costs to be recovered from customers in the future; whereas
- a higher than LRMC-based peak price in areas of our network where demand is falling may encourage inefficient under-use of our network in those areas and result in the loss of only $12/kW of potential cost savings.

Because of the significantly greater cost-consequences of inefficient over-use of our network in growing areas and vastly greater forecast demand growth, as compared with areas of falling demand, we consider it appropriate to base prices across our entire network on the LRMC in growing areas of our network. We present these estimates in Table 18below.

Table 18 - Estimate of LRMC by service

Service	LRMC Estimate ($/kW pa)
Low Voltage	91.3
High Voltage	8.1
Subtransmission	7.8

[27] Calculated equal to $148/kW divided by $8/kW.

2. Translation of LRMC estimates into charging parameters

The average incremental cost approach yields an LRMC estimate for each network service expressed in dollars per kW per annum. However, many customers are not, and indeed cannot, be charged on the basis of their contribution to the network's maximum demand. It is therefore necessary to express these 'dollars per kW per annum' LRMC estimates (hereafter termed 'base LRMC estimates') in terms of the charging parameters that constitute each tariff.

Translation of LRMC into charging parameters for non-TOU energy tariffs

Translation of LRMC into charging parameters for non-TOU tariffs involves two steps, i.e.:

1. Converting the base LRMC estimate using the power factor for a given customer class.

2. Converting the resulting estimate to dollars per kWh by dividing by the number of hours in the year that the variable tariff component can be charged, i.e.:

$$\text{LRMC estimate (\$ per kWh)} = \frac{\text{LRMC (\$ per kW per year)}}{\text{Hours per year}}$$

The table below illustrates this calculation for our flat residential tariff.

Table 19 - Efficient charging parameters for Endeavour Energy's residential flat tariff

Time Period	LRMC of the service ($/kW pa)	LRMC estimate (c/kWh)
Flat Energy	91.3	1.0

Translation of LRMC into charging parameters for TOU energy tariffs

Translation of LRMC into charging parameters for TOU tariffs involves two steps, i.e.:

1. Converting the base LRMC estimate using the power factor for a given customer class.

2. Converting the resulting estimate to dollars per kWh by dividing by the number of hours in the year that the variable tariff component can be charged, i.e.:

$$Peak\ energy\ price\ high\ season = \frac{LRMC \times P(MD) \times (1-\beta^h) \times (1-\alpha)}{number\ of\ high\ season\ peak\ hours}$$

$$Peak\ energy\ price\ low\ season = \frac{LRMC \times P(MD) \times (1-\beta^l) \times (1-\alpha)}{number\ of\ low\ season\ peak\ hours}$$

Where:

$P(MD)$ is the probability of maximum demand occurring in the peak period;

$(1-\beta^h)$ is the per cent allocated to the high-season, and sums to one when added to $(1-\beta^l)$;

$(1-\beta^l)$ is the per cent allocated to the low-season; and

α applies only to large business customers and is the per cent of LRMC recovered from the demand charge, as compared with the peak energy charge, and ensures the *combined* peak energy and demand price signal is appropriately reflects estimated LRMC.

The table below illustrates this calculation for Endeavour Energy's residential seasonal TOU tariff.

Table 20 - Efficient charging parameters for Endeavour Energy's residential flat tariff

Time Period	LRMC of the service ($/kW pa)	LRMC of the service (c/kWh)
High Season	91.3	12.4
Low Season	91.3	3.8

Translation of LRMC into charging parameters for demand tariffs

We have reconsidered the translation of LRMC to demand based charging parameters in our revised proposal. The key changes are:

- The introduction of a diversity factor to ensure the price signal reflects diversity in the timing of each customer's peak demand and their behavioural contribution to maximum demand; and
- The introduction of an allocation factor (β) to better guide the calculation of required difference between high and low season tariffs reflective of differences in seasonal demand.

Translation of LRMC into charging parameters for demand tariffs involves two steps, i.e.:

1. Converting the base LRMC estimate using the power factor for a given customer class (if required).
2. Converting the resulting estimate to dollars per kW or kVA by dividing by the number of months in the year that the variable tariff component can be charged, i.e.:

$$Demand\ price\ high\ season = \frac{LRMC\ \times DF \times P(MD) \times (1-\beta^h) \times \alpha}{Number\ of\ high\ season\ months}$$

$$Demand\ price\ low\ season = \frac{LRMC\ \times DF \times P(MD) \times (1-\beta^l) \times \alpha}{Number\ of\ low\ season\ months}$$

Where:

DF is the per cent diversity factor for the applicable tariff, and ensures the price signal reflects diversity in the timing of each customer's peak demand and their behavioural contribution to maximum demand;

$P(MD)$ is the probability of maximum demand occurring in the peak period;

$(1-\beta^h)$ is the per cent allocated to the high-season, and sums to one when added to $(1-\beta^l)$;

$(1-\beta^l)$ is the per cent allocated to the low-season; and

α applies only to large business customers and is the per cent of LRMC recovered from the demand charge, as compared with the peak energy charge, and ensures the *combined* peak energy and demand price signal is appropriate.

The table below illustrates this calculation for Endeavour Energy's residential demand tariff.

Table 21 - Efficient charging parameters for Endeavour Energy's cost-reflective residential demand tariff

Time Period	LRMC of the service ($/kW pa)	LRMC of the service ($/kW/month)
High Season	91.3	4.1
Low Season	91.3	1.3

Treatment of controlled load

Many of Endeavour Energy's low voltage customers purchase a controlled load service in addition to their standard low voltage service. Endeavour Energy has the capability of interrupting a controlled load during system peak events, and so limiting their contribution to the key driver of LRMC. For this reason, the controlled load service will have a much lower LRMC than its non-controlled equivalent.

Endeavour Energy has two different controlled load services, namely:

- the controlled load 1 service, supplied under the N50 tariff; and
- the controlled load 2 service, supplied under the N54 tariff.

To account for the differing obligations on the network arising from these services, we note that:

- the controlled load 1 service is almost entirely interruptible; and
- the controlled load 2 service is largely interruptible, but can nevertheless contribute to a maximum demand event.

Consistent with these observations, Endeavour Energy has assumed that the controlled load 1 service has an LRMC of zero, and the controlled load 2 service has an LRMC equal to 5 per cent of the non-controlled low voltage service.

Compliance with the LRMC criteria

A necessary condition of efficient tariffs is that the variable components of each tariff must be no less than the LRMC of the service so as to not promote inefficient use of the network.

Based on our estimates of LRMC and our proposed translation of these estimates into tariff components, Endeavour Energy believes that our tariffs are compliant with the LRMC criteria of the Rules.

Appendix 7: Allocation of residual costs

The requirement that a distributor allocate revenues from each tariff in a manner that minimises distortions for efficient use of the network has implications for:

- the manner in which residual costs are recovered from each tariff, i.e., from the different charging parameters that make up each tariff; and
- the manner in which residual costs are recovered from, or allocated to, different tariffs.

1. Allocation of residual costs between tariff parameters

The need to recover a network business's residual costs has critical implications for the charging parameters that it sets. Once a network business has set its charges equal to LRMC, any additional charges levied on the customer have the potential to distort the price signals for efficient usage.

However, the absence of substitutes for the network service means that a customer's decision to purchase an energised connection is highly price inelastic. Put simply, in general it is not feasible for customers to sever their connection to the network in favour of some alternative supply option, even if prices for the service increase.

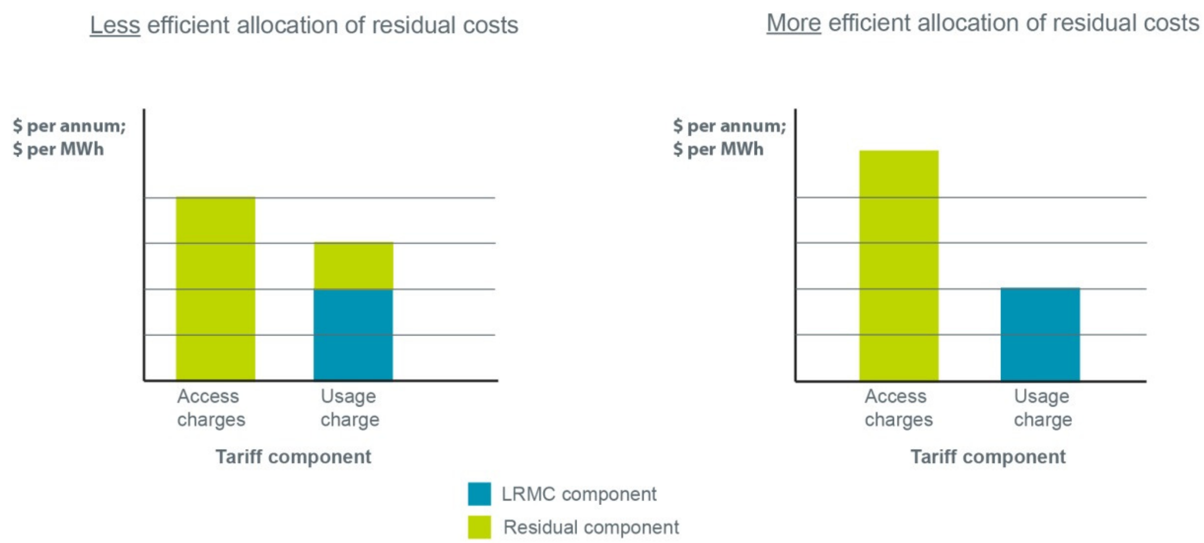
Given that customers will tend to remain connected, it follows that residual costs can generally be recovered via fixed charges, also called 'network access' charges. Because these charges are independent of customer's usage decisions, they have no effect on the price signals for efficient usage of the network service. When the customer's usage charges (either in the form of charges for energy or demand) are set equal to LRMC, the marginal cost to the customer is equal to the marginal cost to the network, which promotes efficiency.

Consider the example of a two-part tariff. Assuming that customers do not have an alternative to the service, a two-part tariff that minimises distortions to price signals comprises:

- an energy charge set at a level equal to LRMC, and
- a fixed charge that recovers any residual costs allocated to the tariff.

A mark-up to usage charges over and above the level of LRMC has the potential to result in inefficient outcomes. However, this assumes that customers' usage of energy is elastic, i.e., that they respond to the signals that they receive for usage of energy.

Figure 19 - Illustrations of the efficiency of different allocations of residual costs for a two-part tariff



In summary, the approach to the allocation of residual costs to tariff components that will minimise distortions to price signals sees the residual costs recovered exclusively from the network access charge.

An exception to this allocation rule occurs where a substitute exists for the service. For example, consider the case of controlled load for water heating, where a customer has the scope to switch to other sources of energy and so disconnect from the controlled load service.

The existence of a substitute for the service has two implications i.e.:

- we would expect a smaller quantum of residual costs to be recovered from this tariff than if there were no substitute; and
- for any residual costs that are ultimately allocated to the tariff, there is no 'hard-and-fast rule' as to the manner in which these costs should be allocated across the two charging parameters.

In particular, it is incorrect to assume that residual costs should be simply recovered via the fixed charge. It will often be sensible to mark-up usage charges rather than fixed charges, so as to ensure that customers with low levels of usage do not cease to purchase the service.

As discussed above, from an economic perspective it is important to ensure that mark-up to LRMC-based prices for residual costs is minimised. The easiest way to achieve this is to recover residual costs via the fixed charge. Endeavour Energy believes, however, that recovery all residual costs from the fixed charge tariff component is at odds with the customer impact principle.

2. Recovery of residual costs from different tariffs

A second consideration is whether the manner in which residual costs are recovered from distinct tariffs distorts price signals for efficient usage of the network. For example, consider the case where a customer has an option of choosing a flat energy or a demand based tariff.

Assuming that both tariffs have been set based on LRMC, the demand based tariff provides a more efficient price signal than the flat energy tariff. Provided that the benefits of transitions outweigh the costs, over time a network business should encourage customers moving towards the most efficient tariff structures.

Consistent with the Rules, the allocation of residual costs across these three tariffs should harness, or alternatively minimise distortions to, the price signals for efficient usage that these tariffs provide.

Our approach to allocating residual costs across tariffs involves three considerations, or principles:

- for tariffs where customers have no alternative tariff, or where the structure of alternative tariffs provides the same strength signals for efficient usage, there is no ‘hard and fast’ rule as to how they should be allocated, so long as the allocation does not violate the customer impact principle;
- for tariffs where a customer can switch to a tariff with a different strength price signal, residual costs should be assigned so as to encourage customers to shift to tariffs that have the most efficient price signal. Put another way, residual costs should be allocated to tariffs so that customers on more efficient tariffs pay a smaller quantum of residual costs; and
- over time charging parameters will need to be rebalanced to ensure that the shifting of customers between tariffs:
  - does not lead to under- or over-recovery of revenue; and
  - does not result in unacceptable bill shock.

Appendix 8: Pass through of specified costs

Endeavour Energy passes-through a number of costs that we incur in our tariffs including transmission costs and Climate Change Fund jurisdictional scheme costs. Our approach to the pass-through of these costs is set out below.

1. Transmission costs

Endeavour Energy's transmission cost recovery (TCR) tariffs are designed to recover transmission related costs, including TransGrid's transmission use of system (TUOS) charges, avoided transmission payments made to embedded generators, and adjustments to balance Endeavour Energy's transmission overs and unders account. The TCR tariffs comprise part of the overall Network Tariffs.

The TCR amount to be passed on to customers for a particular regulatory year must not exceed the estimated transmission related costs including the overs and unders adjustment amount.

The over and under recovery amount is calculated in a way that:

- ensures that Endeavour Energy is able to recover from customers no more and no less than the transmission related costs it incurs; and
- adjusts for an appropriate cost of capital that is consistent with the allowed rate of return used in the Endeavour Energy determination for the relevant regulatory year.

The key principles of Endeavour Energy's TCR methodology are:

- total TUOS allocated to network tariffs are aligned with the total estimated transmission charge to be paid by Endeavour Energy, adjusted for any overs and unders account balance;
- transmission charges are allocated to network tariffs in a manner that reflects the cost drivers present in transmission pricing;
- customers on an individually calculated tariff have transmission charges allocated in a manner that preserves the location and time signals of transmission pricing; and
- network tariffs for smaller customer classes have transmission charges allocated on an energy basis, as location signals cannot be preserved in all cases due to metering limitations.

2. Climate Change Fund Jurisdictional Scheme Costs

Endeavour Energy is required to contribute to the Climate Change Fund (CCF) scheme which is managed by the NSW Government. Each year Endeavour Energy is notified of the amount that it will be required to pay in the next financial year. This contribution amount, adjusted for over or unders, is recovered from customers through the CCF tariffs. The CCF tariffs comprise part of the overall Network Tariffs.

CCF recovery tariffs have been in place since 1 July 2005 and are levied on the energy (kWh) based charging parameter of tariffs only. Existing tariffs are annually adjusted such that the weighted average price change for the CCF recovery portion of network price is evenly applied to all tariffs to achieve the required recovery amount (subject to the 25% cap placed by the NSW Government on residential tariff contributions to the CCF).

Endeavour Energy does not recover a contribution to the CCF from:

- controlled load tariffs as customers contribute to the fund through their primary tariff; or
- inter-distributor transfer tariffs as customers contribute to the fund through the tariffs offered by the destination distributor.

The CCF amount to be passed on to customers for a particular regulatory year must not exceed the CCF contribution amount adjusted for over or under recoveries in previous years.

The over and under recovery amount is calculated in a way that:

- ensures that Endeavour Energy is able to recover from customers no more and no less than the CCF scheme costs it incurs; and
- adjusts for an appropriate cost of capital that is consistent with the allowed rate of return used in the Endeavour Energy determination for the relevant regulatory year.

Appendix 9: Indicative pricing schedule

The tables below set out the indicative prices for our standard control services for the regulatory period.

During the TSS period, Endeavour Energy may need to introduce new tariff codes for billing purposes. Any new tariff codes introduced will comply with the tariff structures outlined in this Tariff Structure Statement and the price level for NUOS services will equate to the tariff type under which the new tariff code has been created. Some tariffs codes include generated energy (credit) rate components in addition to the charging parameters.

Indicative prices for alternative control services are provided as attachments to our Revised Regulatory Proposal:

- Metering - Attachment 0.18;
- Public Lighting – Attachment 0.16; and
- Ancillary Network Services – Attachment 0.17.

Our proposed charges for our security lights (Nightwatch) services for the 2019-24 period are unchanged from the AER's draft decision.

Table 22 - 2019/2020 Indicative network pricing

Tariff type	Fixed ($/day)	Non TOU Energy consumption (c/kWh)		TOU Energy consumption (c/kWh)			Demand ($/kVA or kW/mth)	
	Daily	Anytime/ Step 1	Step 2	High Season Peak / Peak	Low Season Peak / Shoulder	Off Peak	High Season	Low Season
Residential Energy	0.3681	8.6227						
Residential TOU (Obsolete)	0.4047			12.3840	8.1290	7.6710		
Residential Seasonal TOU	0.4047			19.4775	10.8215	7.0705		
Residential Demand	0.4047	5.8119					4.0890	1.2520
Residential Demand (Transitional)	0.4047	7.2815					1.0000	0.3062
General Supply (GS) Energy	0.5268	8.7032	9.6528					
GS TOU (Obsolete)	0.5795			11.9813	7.7263	7.2683		
GS Seasonal TOU	0.5795			20.0229	11.3669	7.6159		
GS Demand	0.5795	6.5980					5.6230	1.7210
GS Demand (Transitional)	0.5795	7.9713					1.0000	0.3061
Controlled Load 1	0.0324	1.4138						
Controlled Load 2	0.0324	3.3512						
LV TOU Demand	20.5400			3.9714	3.3914	2.0024	10.1349	8.6509
LV TOU Demand Transition	20.5400			18.2205	15.3205	8.3735		
HV TOU Demand	35.2900			1.6974	1.6464	1.5264	8.8189	8.6909
ST TOU Demand	55.4800			1.1589	1.1119	0.9999	7.1307	7.0107
Unmetered Energy		8.7032						
Unmetered Street Lighting		7.8399						
Unmetered Traffic Lights		8.7032						
Unmetered Night Watch		6.9047						

Table 23 - 2020/2021 Indicative network pricing

Tariff type	Fixed ($/day)	Non TOU Energy consumption (c/kWh)		TOU Energy consumption (c/kWh)			Demand ($/kVA or kW/mth)	
	Daily	Anytime/ Step 1	Step 2	High Season Peak / Peak	Low Season Peak / Shoulder	Off Peak	High Season	Low Season
Residential Energy	0.3875	8.7484						
Residential TOU (Obsolete)	0.4159			12.8214	8.4600	7.9906		
Residential Seasonal TOU	0.4159			19.9439	11.0715	7.2267		
Residential Demand	0.4159	5.9447					4.1912	1.2833
Residential Demand (Transitional)	0.4159	7.2260					1.4600	0.4470
General Supply (GS) Energy	0.5546	8.8779	9.8942					
GS TOU (Obsolete)	0.5956			12.3230	7.9616	7.4922		
GS Seasonal TOU	0.5956			20.5126	11.6402	7.7954		
GS Demand	0.5956	6.7566					5.7636	1.7640
GS Demand (Transitional)	0.5956	7.9655					1.6700	0.5111
Controlled Load 1	0.0373	1.5120						
Controlled Load 2	0.0373	3.4897						
LV TOU Demand	22.6500			4.1667	3.5722	2.1484	9.7470	8.2259
LV TOU Demand Transition	22.6500			18.7525	15.7800	8.6593		
HV TOU Demand	38.9200			1.7605	1.7082	1.5852	8.8558	8.7246
ST TOU Demand	61.1900			1.2204	1.1722	1.0574	7.1545	7.0315
Unmetered Energy		8.8779						
Unmetered Street Lighting		7.9986						
Unmetered Traffic Lights		8.8779						
Unmetered Night Watch		7.1984						

Table 24 - 2021/2022 Indicative network pricing

Tariff type	Fixed ($/day)	Non TOU Energy consumption (c/kWh)		TOU Energy consumption (c/kWh)			Demand ($/kVA or kW/mth)	
	Daily	Anytime/ Step 1	Step 2	High Season Peak / Peak	Low Season Peak / Shoulder	Off Peak	High Season	Low Season
Residential Energy	0.4068	8.7043						
Residential TOU (Obsolete)	0.4262			13.1375	8.6671	8.1859		
Residential Seasonal TOU	0.4262			20.2527	11.1585	7.2176		
Residential Demand	0.4262	5.9182					4.2960	1.3154
Residential Demand (Transitional)	0.4262	7.0248					1.9200	0.5879
General Supply (GS) Energy	0.5823	8.8375	9.8411					
GS TOU (Obsolete)	0.6104			12.4949	8.0245	7.5433		
GS Seasonal TOU	0.6104			20.7969	11.7027	7.7618		
GS Demand	0.6104	6.7029					5.9077	1.8081
GS Demand (Transitional)	0.6104	7.7476					2.3400	0.7162
Controlled Load 1	0.0428	1.6290						
Controlled Load 2	0.0428	3.6517						
LV TOU Demand	24.9100			4.2776	3.6682	2.2089	9.3348	7.7757
LV TOU Demand Transition	24.9100			19.1065	16.0597	8.7610		
HV TOU Demand	42.8100			1.7736	1.7200	1.5939	8.9187	8.7842
ST TOU Demand	67.3000			1.2383	1.1889	1.0712	7.1920	7.0659
Unmetered Energy		8.8375						
Unmetered Street Lighting		7.9517						
Unmetered Traffic Lights		8.8375						
Unmetered Night Watch		7.4823						

Table 25 - 2022/2023 Indicative network pricing

Tariff type	Fixed ($/day)	Non TOU Energy consumption (c/kWh)		TOU Energy consumption (c/kWh)			Demand ($/kVA or kW/mth)	
	Daily	Anytime/ Step 1	Step 2	High Season Peak / Peak	Low Season Peak / Shoulder	Off Peak	High Season	Low Season
Residential Energy	0.4271	8.6271						
Residential TOU (Obsolete)	0.4368			13.4308	8.8486	8.3554		
Residential Seasonal TOU	0.4368			20.5436	11.2220	7.1826		
Residential Demand	0.4368	5.8620					4.4034	1.3483
Residential Demand (Transitional)	0.4368	6.7892					2.3800	0.7287
General Supply (GS) Energy	0.6114	8.8514	9.8511					
GS TOU (Obsolete)	0.6256			12.7276	8.1454	7.6522		
GS Seasonal TOU	0.6256			21.1472	11.8257	7.7863		
GS Demand	0.6256	6.7067					6.0554	1.8533
GS Demand (Transitional)	0.6256	7.5870					3.0100	0.9212
Controlled Load 1	0.0492	1.7285						
Controlled Load 2	0.0492	3.7657						
LV TOU Demand	27.4000			4.3649	3.7403	2.2445	8.8847	7.2866
LV TOU Demand Transition	27.4000			19.4430	16.3201	8.8389		
HV TOU Demand	47.0900			1.7704	1.7155	1.5863	8.9805	8.8427
ST TOU Demand	74.0300			1.2428	1.1922	1.0715	7.2289	7.0997
Unmetered Energy		8.8514						
Unmetered Street Lighting		7.9549						
Unmetered Traffic Lights		8.8514						
Unmetered Night Watch		7.7771						

Table 26 - 2023/2024 Indicative network pricing

Tariff type	Fixed ($/day)	Non TOU Energy consumption (c/kWh)		TOU Energy consumption (c/kWh)			Demand ($/kVA or kW/mth)	
	Daily	Anytime/ Step 1	Step 2	High Season Peak / Peak	Low Season Peak / Shoulder	Off Peak	High Season	Low Season
Residential Energy	0.4464	8.4509						
Residential TOU (Obsolete)	0.4464			13.7252	9.0285	8.5229		
Residential Seasonal TOU	0.4464			20.7377	11.1831	7.0427		
Residential Demand	0.4464	5.7005					4.5135	1.3820
Residential Demand (Transitional)	0.4464	6.4494					2.8400	0.8696
General Supply (GS) Energy	0.6394	8.7777	9.7669					
GS TOU (Obsolete)	0.6394			12.8714	8.1747	7.6692		
GS Seasonal TOU	0.6394			21.4143	11.8596	7.7192		
GS Demand	0.6394	6.6183					6.2067	1.8997
GS Demand (Transitional)	0.6394	7.3387					3.6800	1.1263
Controlled Load 1	0.0564	1.8184						
Controlled Load 2	0.0564	3.8549						
LV TOU Demand	30.0500			4.3997	3.7595	2.2263	8.3431	6.7050
LV TOU Demand Transition	30.0500			19.6595	16.4584	8.7902		
HV TOU Demand	51.6500			1.7237	1.6674	1.5350	9.0024	8.8611
ST TOU Demand	81.2100			1.2173	1.1654	1.0418	7.2453	7.1128
Unmetered Energy		8.7777						
Unmetered Street Lighting		7.8841						
Unmetered Traffic Lights		8.7777						
Unmetered Night Watch		8.0497						

Appendix 10: Bill impact analysis

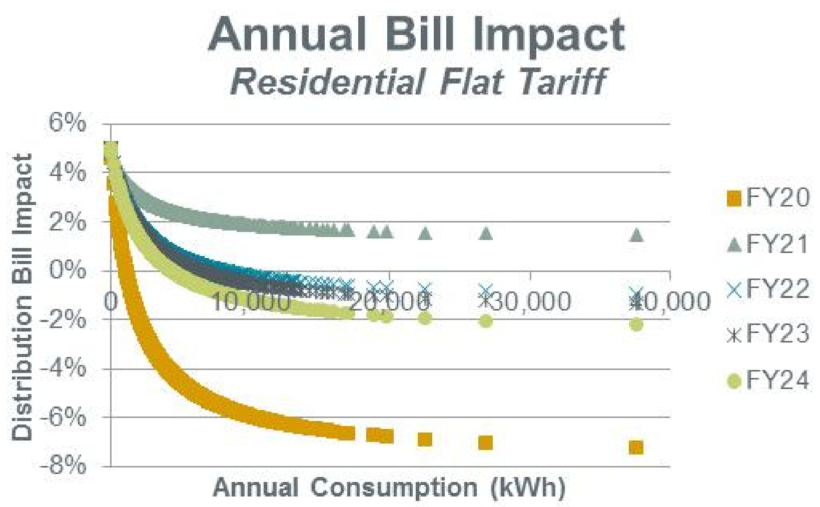
1. Residential tariffs

1.1 Residential flat energy tariff

The figure below illustrates the expected distribution network bill impacts for residential customers on the flat energy tariff. Bill impacts include estimated CPI of 2.4% and are set using our smoothed annual revenue requirement as proposed in our Revised Regulatory Proposal.

The fixed charge for this tariff has been increased annually at a rate of 5.0%. At this growth rate it is expected that the fixed charges for the residential flat energy tariff and residential transitional demand tariff will reach parity in 2023/24.

Figure 20 – Illustrative annual increase in distribution network bill – residential flat tariff



1.2 Residential transitional demand tariff

During our stakeholder engagement processes, stakeholders made it clear that having both TOU energy and demand based tariff components in the one tariff was overly complex and unlikely to be understood by customers or passed through by retailers in the retail price. It was agreed that our TSS submission would propose more simplistic cost-reflective tariffs structured with a fixed charge, a flat energy rate and a seasonal demand charge.

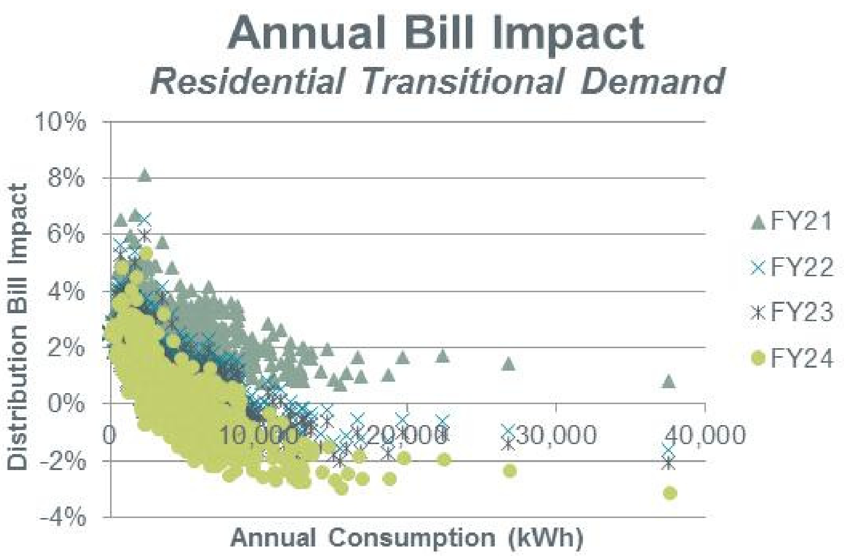
Endeavour Energy is proposing to transition the demand charging parameters of this tariff over a ten year period.

The figure below illustrates the expected distribution network bill impacts for residential customers on the proposed transitional demand tariff. Bill impacts include estimated CPI of 2.4% and are set using our smoothed annual revenue requirement as proposed in our Revised Regulatory Proposal. Due to a lack of residential customers with interval metering, this analysis is based on sample residential customer data.

The fixed charge for this tariff has been increased annually at a rate of 2.5%. At this growth rate it is expected that the fixed charges for the residential flat energy tariff and residential transitional demand tariff will reach parity in 2023/24.

A 10% increase in a residential customer's distribution bill is expected to translate to a 3% increase in retail bill.

Figure 21 – Illustrative annual increase in distribution network bill – residential transitional demand tariff

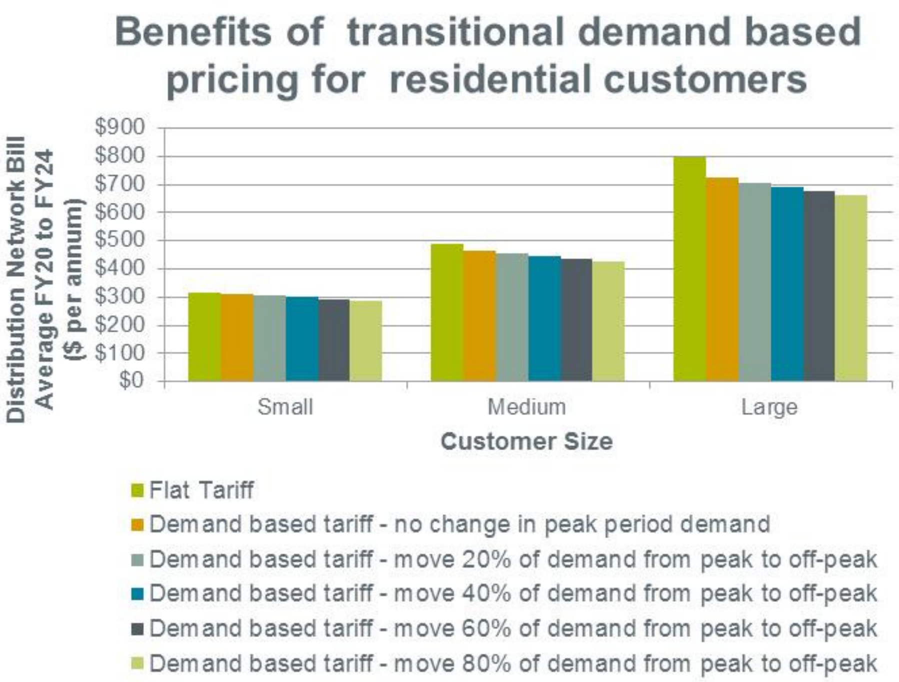


The figure above illustrates the annual movement in distribution network bill of residential customers on the transitional demand tariff. It is important to note that this analysis:

- assumes that customers make no change in their demand for energy in response to the demand based signal.
- provides no bill comparison to the flat energy tariff for these customers.

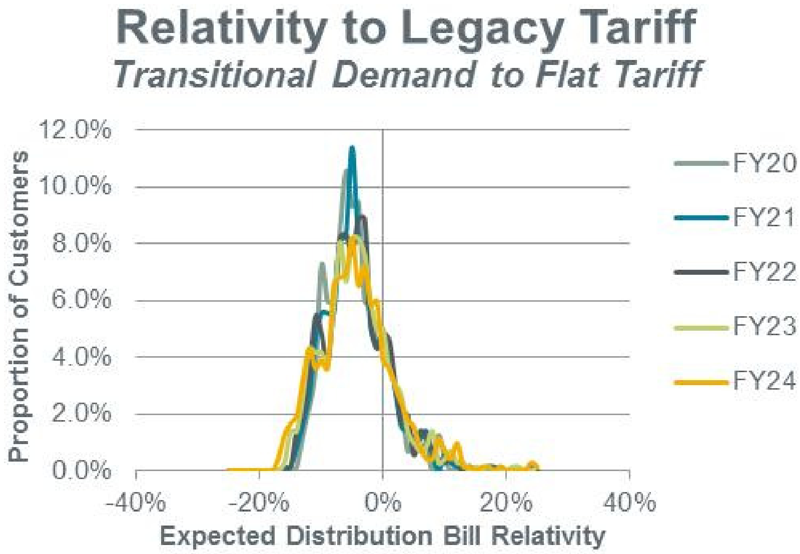
The figure below illustrates the expected average annual distribution bill for small, medium and large residential customers on the flat energy and transitional demand based tariff. It also illustrates the benefit of demand based pricing on a customer's bill if they were to move a portion of their demand from the peak to off-peak period.

Figure 22 – Benefits of transitional demand based pricing for residential customers



The figure below illustrates the expected tariff relativity between the residential flat energy tariff and the residential transitional demand tariff. Customers on the negative side of the distribution are expected to pay a lower network bill on the transitional demand tariff relative to what they would pay on the flat energy tariff. As demonstrated above, if the customer chooses to respond to the demand based pricing signal, greater savings are possible.

Figure 23 – Illustrative distribution network bill relativity – residential transitional demand & flat tariffs



1.3 Residential demand tariff

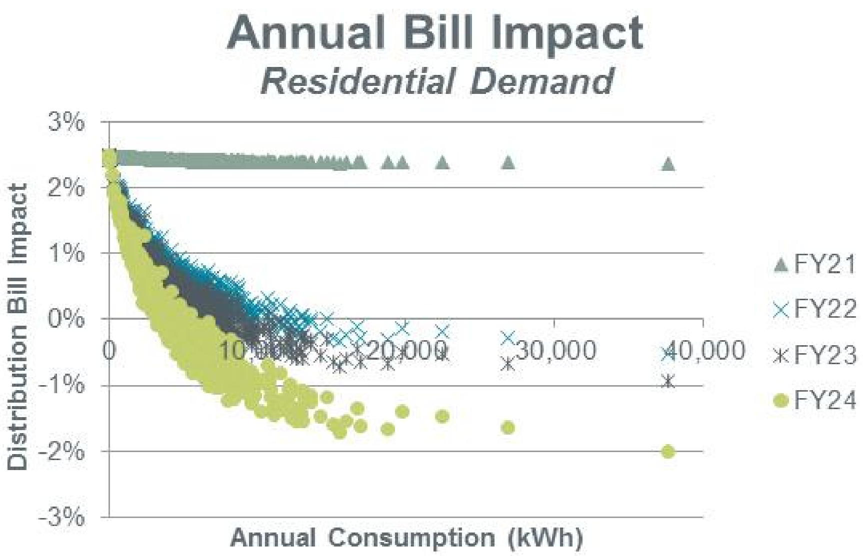
Endeavour Energy will also offer a fully cost reflective opt-in demand tariff for customers willing to lead the way to cost reflective tariffs.

The figure below illustrates the expected distribution network bill impacts for residential customers on the proposed demand tariff. Bill impacts include estimated CPI of 2.4% and are set using our smoothed annual revenue requirement as proposed in our Revised Regulatory Proposal. Due to a lack of residential customers with interval metering, this analysis is based on sample residential customer data.

The fixed charge for this tariff has been increased annually at a rate of 2.5%. At this growth rate it is expected that the fixed charges for the residential flat energy tariff and residential demand tariff will reach parity in 2023/24.

A 10% increase in a residential customer’s distribution bill is expected to translate to a 3% increase in retail bill.

Figure 24 – Illustrative annual increase in distribution network bill – residential demand tariff

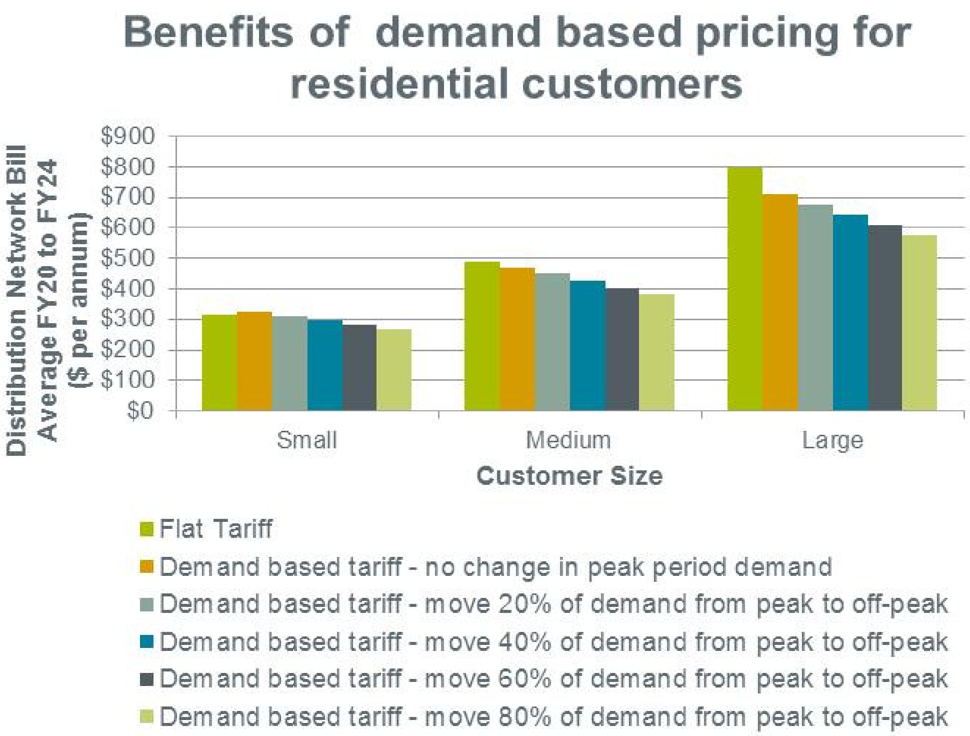


The figure above illustrates the annual movement in distribution network bill of residential customers on the demand tariff. It is important to note that this analysis:

- assumes that customers make no change in their demand for energy in response to the demand based signal.
- provides no bill comparison to the flat energy tariff for these customers.

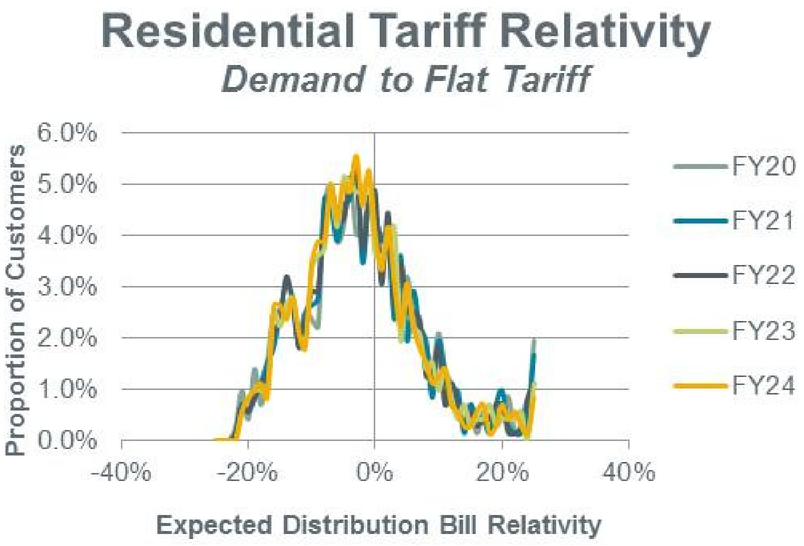
The figure below illustrates the expected average annual distribution bill for small, medium and large residential customers on the flat energy and demand based tariff. It also illustrates the benefit of demand based pricing on a customer's bill if they were to move a portion of their demand from the peak to off-peak period.

Figure 25 – Benefits of demand based pricing for residential customers



The figure below illustrates the expected tariff relativity between the residential flat energy tariff and the residential demand tariff. Customers on the negative side of the distribution are expected to pay a lower network bill on the demand tariff relative to what they would pay on the flat energy tariff. As demonstrated above, if the customer chooses to respond to the demand based pricing signal, greater savings are possible.

Figure 26 – Illustrative distribution network bill relativity – residential demand & flat tariffs



1.4 Residential seasonal time of use tariff

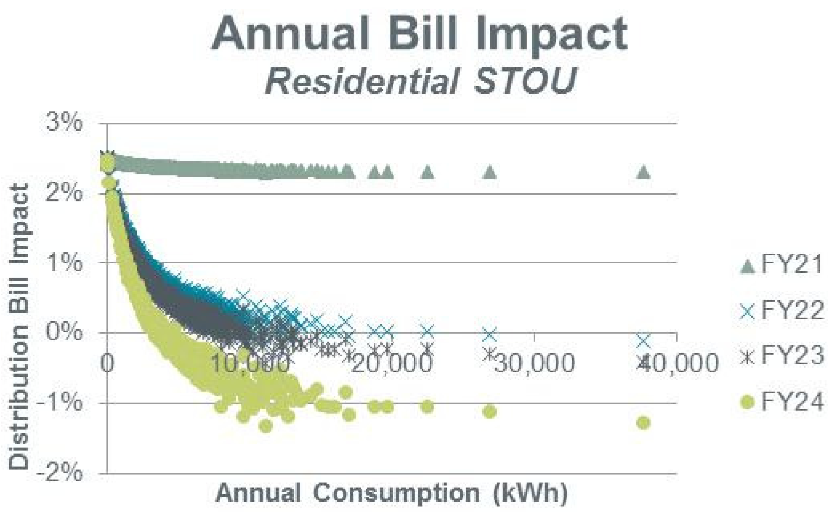
Endeavour Energy will also offer a fully cost reflective opt-in seasonal time of use (STOU) tariff.

The figure below illustrates the expected distribution network bill impacts for residential customers on the proposed STOU tariff. Bill impacts include estimated CPI of 2.4% and are set using our smoothed annual revenue requirement as proposed in our Revised Regulatory Proposal. Due to a lack of residential customers with interval metering, this analysis is based on sample residential customer data.

The fixed charge for this tariff has been increased annually at a rate of 2.5%. At this growth rate it is expected that the fixed charges for the residential flat energy tariff and residential STOU tariff will reach parity in 2023/24.

A 10% increase in a residential customer's distribution bill is expected to translate to a 3% increase in retail bill.

Figure 27 – Illustrative annual increase in distribution network bill – residential STOU tariff

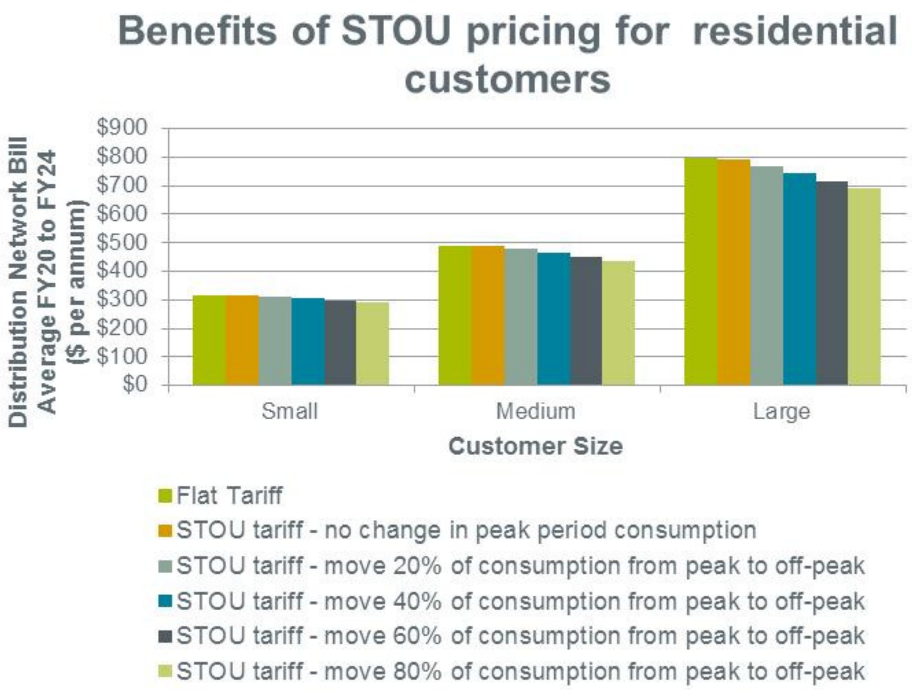


The figure above illustrates the annual movement in distribution network bill of residential customers on the STOU tariff. It is important to note that this analysis:

- assumes that customers make no change in their demand for energy in response to the energy based signal.
- provides no bill comparison to the flat energy tariff for these customers.

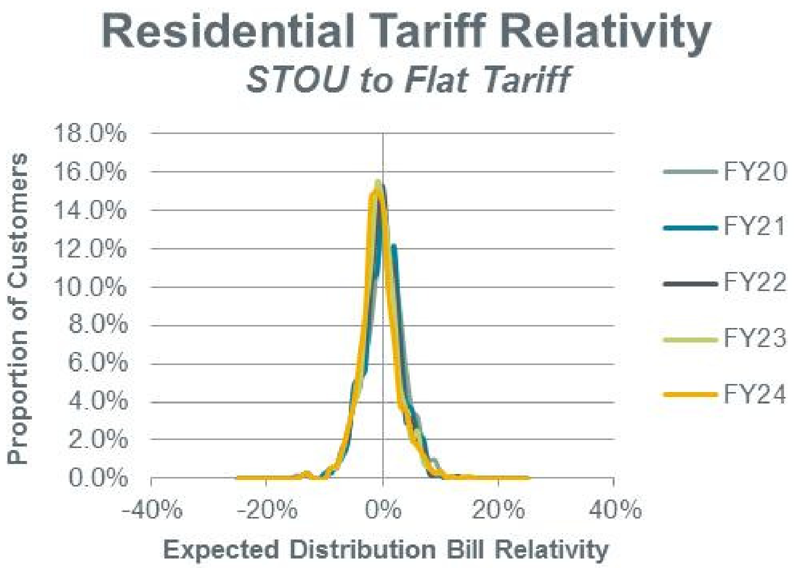
The figure below illustrates the expected average annual distribution bill for small, medium and large residential customers on the flat energy and STOU tariff. It also illustrates the benefit of STOU based pricing on a customer's bill if they were to move a portion of their energy consumption from the peak to off-peak period.

Figure 28 – Benefits of STOU pricing for residential customers



The figure below illustrates the expected tariff relativity between the residential flat energy tariff and the residential STOU tariff. Customers on the negative side of the distribution are expected to pay a lower network bill on the STOU tariff relative to what they would pay on the flat energy tariff. As demonstrated above, if the customer chooses to respond to the STOU pricing signal, greater savings are possible.

Figure 29 – Illustrative distribution network bill relativity – residential STOU & flat tariffs



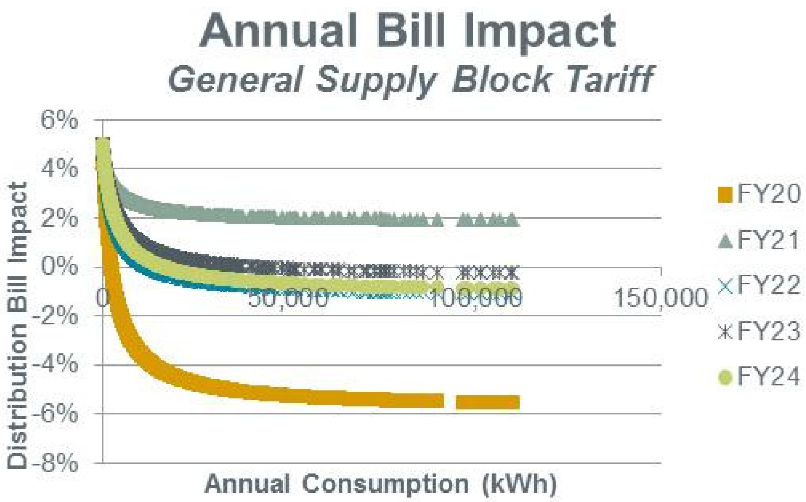
2. General supply

2.1 General supply block tariff

The figure below illustrates the expected distribution network bill impacts for general supply customers on the block energy tariff. Bill impacts include estimated CPI of 2.4% and are set using our smoothed annual revenue requirement as proposed in our Revised Regulatory Proposal.

The fixed charge for this tariff has been increased annually at a rate of 5.0% At this growth rate it is expected that the fixed charges for the general supply block energy and the general supply transitional demand tariff will reach parity in 2023/24.

Figure 30 – Illustrative annual increase in distribution network bill – general supply block tariff



2.2 General supply transitional demand tariff

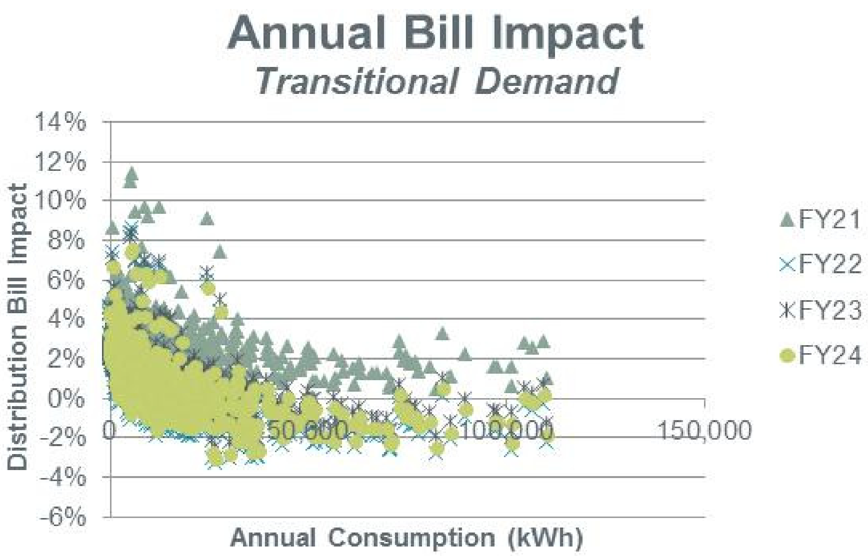
During our stakeholder engagement processes, stakeholders made it clear that having both TOU energy and demand based tariff components in the one tariff was overly complex and unlikely to be understood by customers or passed through by retailers in the retail price. It was agreed that our TSS submission would propose more simplistic cost-reflective tariffs structured with a fixed charge, a flat energy rate and a seasonal demand charge.

The figure below illustrates the expected distribution network bill impacts for general supply customers on the proposed transitional demand tariff. Bill impacts include estimated CPI of 2.4% and are set using our smoothed annual revenue requirement as proposed in our Revised Regulatory Proposal. Due to a lack of general supply customers with interval metering, this analysis is based on sample general supply customer data.

The fixed charge for this tariff has been increased annually at a rate of 2.5%. At this growth rate it is expected that the fixed charges for the general supply block energy and the general supply transitional demand tariff will reach parity in 2023/24.

A 10% distribution network bill impact for a general supply customer is expected to translate to a 3% retail bill impact.

Figure 31 – Illustrative annual increase in distribution network bill – general supply transitional demand tariff

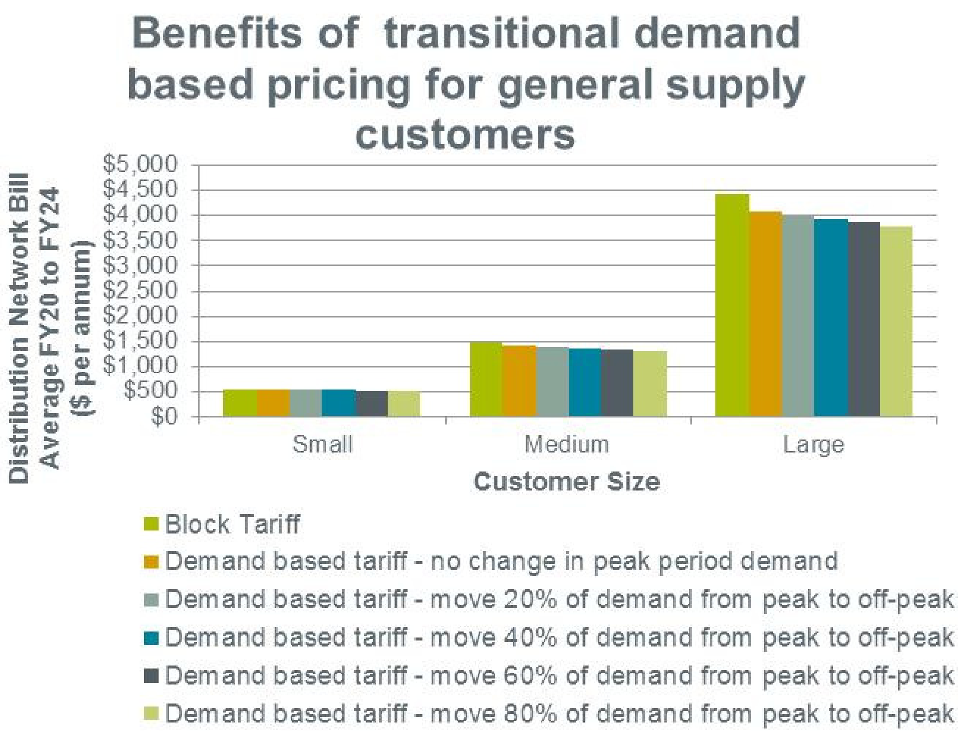


The figure above illustrates the annual movement in distribution network bill of general supply customers on the transitional demand tariff. It is important to note that this analysis:

- assumes that customers make no change in their demand for energy in response to the demand based signal.
- provides no bill comparison to the flat energy tariff for these customers.

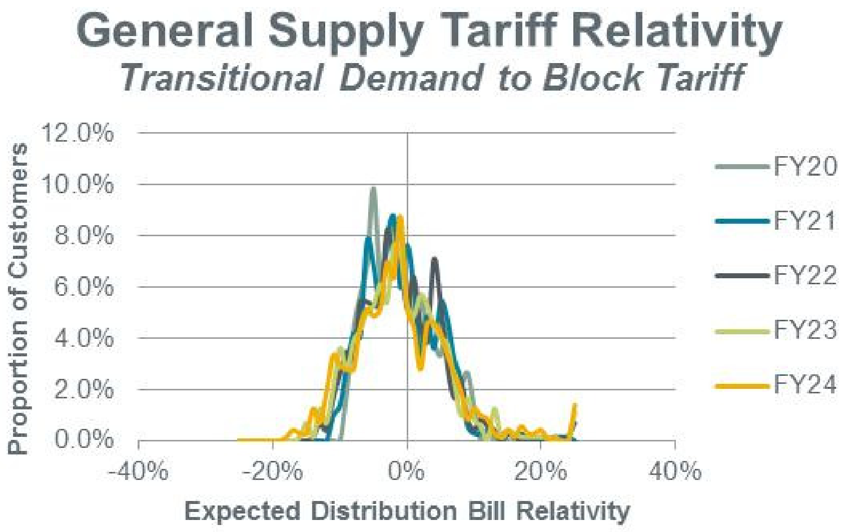
The figure below illustrates the expected average annual distribution bill for small, medium and large general supply customers on the block energy tariff and demand based tariff. It also illustrates the benefit of demand based pricing on a customer's bill if they were to move a portion of their demand from the peak to off-peak period.

Figure 32 – Benefits of transitional demand based pricing for general supply customers



The figure below illustrates the expected tariff relativity between the general supply block energy tariff and the general supply transitional demand tariff. Customers on the negative side of the distribution are expected to pay a lower network bill on the transitional demand tariff relative to what they would pay on the block energy tariff. As demonstrated above, if the customer chooses to respond to the demand based pricing signal, greater savings are possible.

Figure 33 – Illustrative distribution network bill relativity – general supply transitional demand & block tariffs



2.3 General supply demand tariff

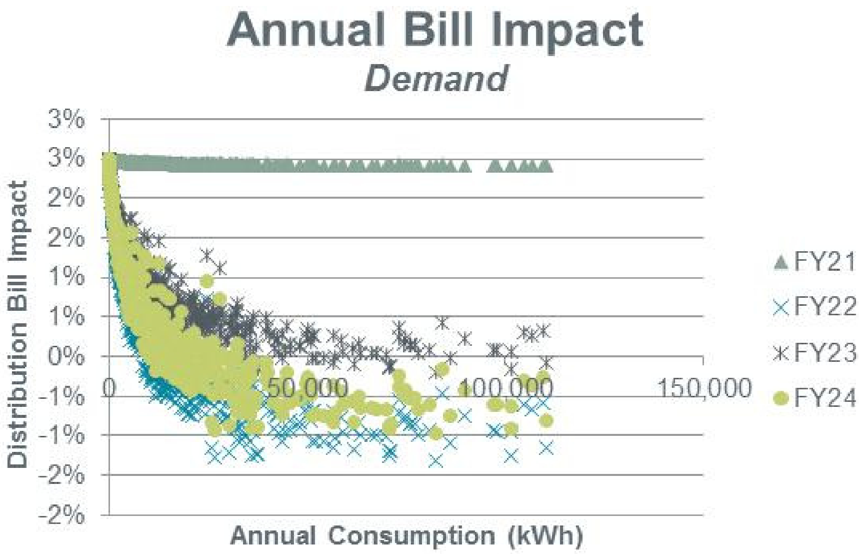
Endeavour Energy will also offer a fully cost reflective opt-in demand tariff for customers willing to lead the way to cost reflective tariffs.

The figure below illustrates the expected distribution network bill impacts for general supply customers on the proposed demand tariff. Bill impacts include estimated CPI of 2.4% and are set using our smoothed annual revenue requirement as proposed in our Revised Regulatory Proposal. Due to a lack of general supply customers with interval metering, this analysis is based on sample general supply customer data.

The fixed charge for this tariff has been increased annually at a rate of 2.5%. At this growth rate it is expected that the fixed charges for the general supply block energy and the general supply demand tariff will reach parity in 2023/24.

A 10% distribution network bill impact for a general supply customer is expected to translate to a 3% retail bill impact.

Figure 34 – Illustrative annual increase in distribution network bill – general supply demand tariff

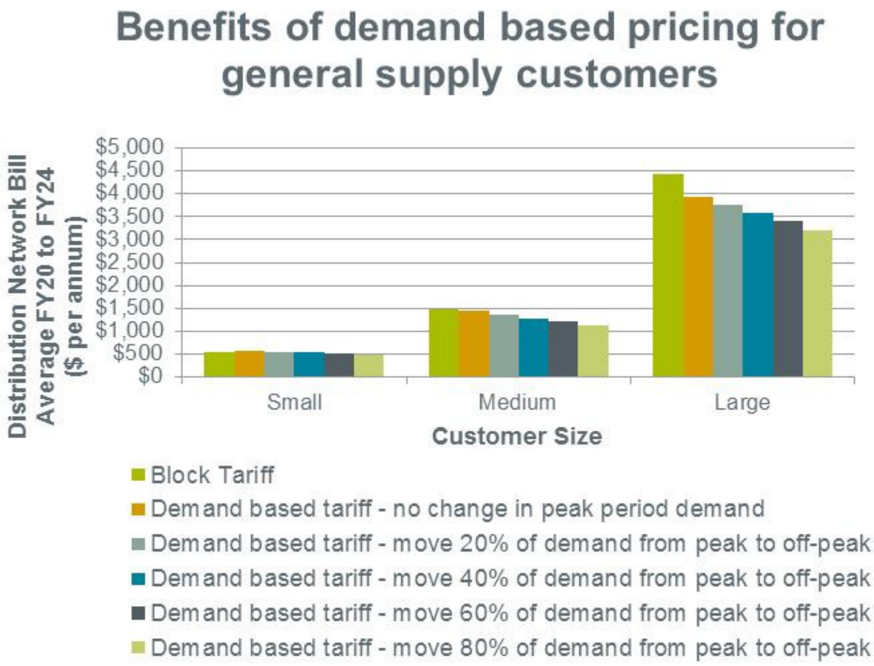


The figure above illustrates the annual movement in distribution network bill of general supply customers on the demand tariff. It is important to note that this analysis:

- assumes that customers make no change in their demand for energy in response to the demand based signal.
- provides no bill comparison to the flat energy tariff for these customers.

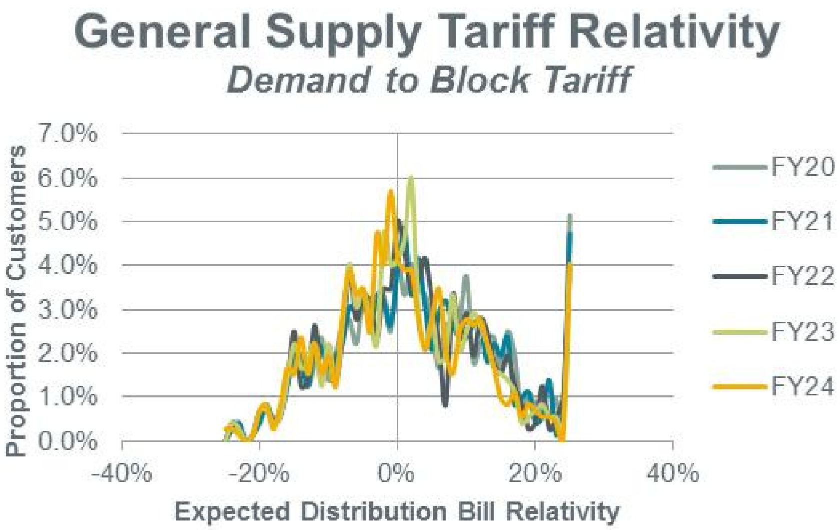
The figure below illustrates the expected average annual distribution bill for small, medium and large general supply customers on the block energy tariff and demand based tariff. It also illustrates the benefit of demand based pricing on a customer's bill if they were to move a portion of their demand from the peak to off-peak period.

Figure 35 – Benefits of demand based pricing for general supply customers



The figure below illustrates the expected tariff relativity between the general supply block energy tariff and the general supply demand tariff. Customers on the negative side of the distribution are expected to pay a lower network bill on the transitional demand tariff relative to what they would pay on the block energy tariff. As demonstrated above, if the customer chooses to respond to the demand based pricing signal, greater savings are possible.

Figure 36 – Illustrative distribution network bill relativity – general supply demand & block tariffs



2.4 General supply seasonal time of use tariff

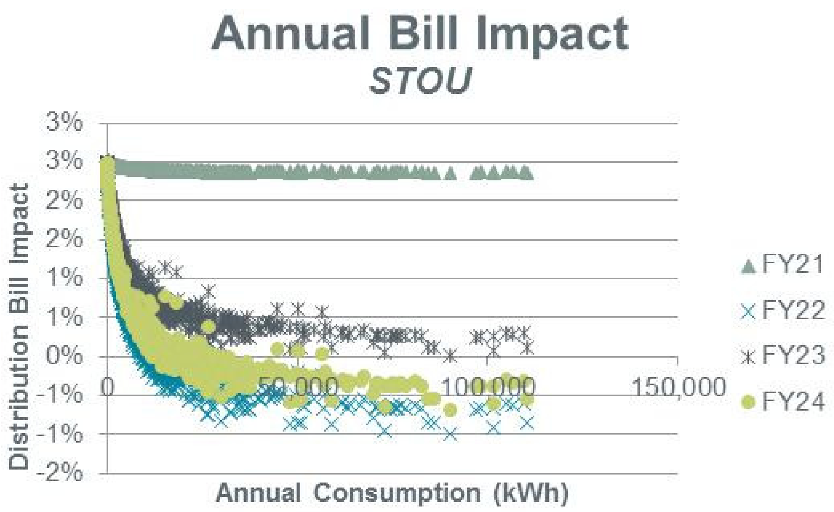
Endeavour Energy will also offer a fully cost reflective opt-in seasonal time of use (STOU) tariff.

The figure below illustrates the expected distribution network bill impacts for general supply customers on the proposed STOU tariff. Bill impacts include estimated CPI of 2.4% and are set using our smoothed annual revenue requirement as proposed in our Revised Regulatory Proposal. Due to a lack of general supply customers with interval metering, this analysis is based on sample general supply customer data.

The fixed charge for this tariff has been increased annually at a rate of 2.5%. At this growth rate it is expected that the fixed charges for the general supply block energy and the general supply STOU tariff will reach parity in 2023/24.

A 10% distribution network bill impact for a general supply customer is expected to translate to a 3% retail bill impact.

Figure 37 – Illustrative annual increase in distribution network bill – general supply STOU tariff

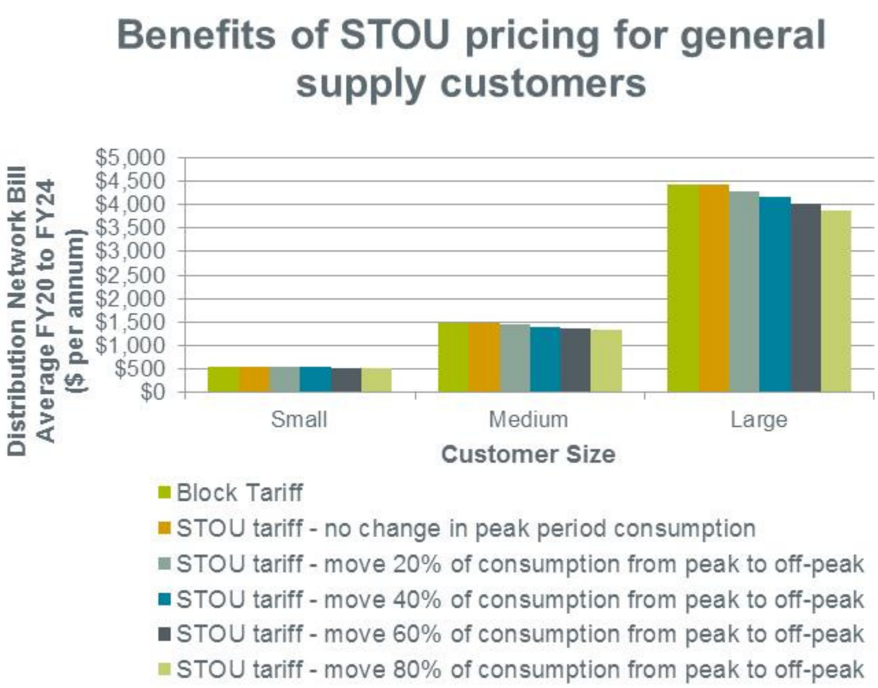


The figure above illustrates the annual movement in distribution network bill of general supply customers on the STOU tariff. It is important to note that this analysis:

- assumes that customers make no change in their demand for energy in response to the demand based signal.
- provides no bill comparison to the flat energy tariff for these customers.

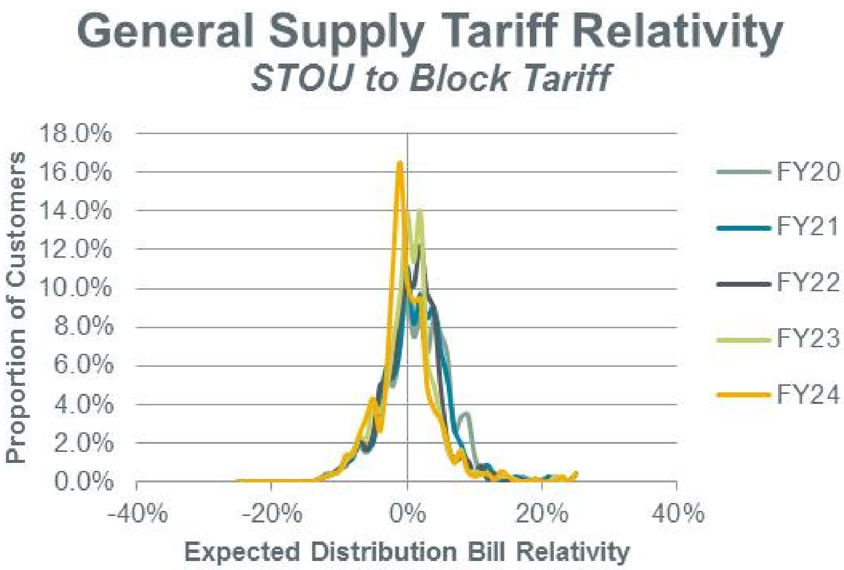
The figure below illustrates the expected average annual distribution bill for small, medium and large general supply customers on the block energy tariff and STOU tariff. It also illustrates the benefit of STOU pricing on a customer's bill if they were to move a portion of their energy consumption from the peak to off-peak period.

Figure 38 – Benefits of STOU pricing for general supply customers



The figure below illustrates the expected tariff relativity between the general supply block energy tariff and the general supply STOU tariff. Customers on the negative side of the distribution are expected to pay a lower network bill on the transitional demand tariff relative to what they would pay on the block energy tariff. As demonstrated above, if the customer chooses to respond to the STOU pricing signal, greater savings are possible.

Figure 39 – Illustrative distribution network bill relativity – general supply STOU & block tariffs



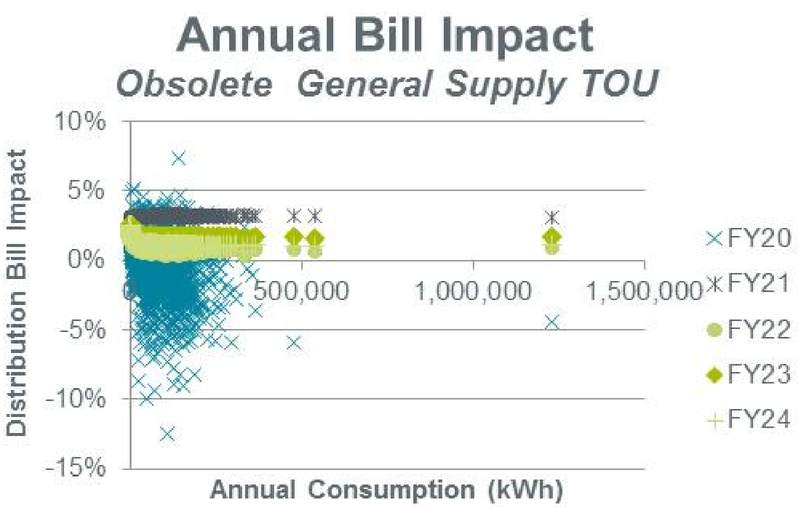
2.1 Obsolete General supply time of use tariff

There are approximately 2,500 general supply customers currently taking supply on the obsolete general supply TOU energy tariff.

The figure below illustrates the expected distribution network bill impacts for general supply customers on the proposed STOU tariff. Bill impacts include estimated CPI of 2.4% and are set using our smoothed annual revenue requirement as proposed in our Revised Regulatory Proposal.

A 10% distribution network bill impact for a general supply customer is expected to translate to a 3% retail bill impact.

Figure 40 – Illustrative annual increase in distribution network bill – obsolete general supply TOU tariff



Endeavour Energy plans to transfer customers away from the obsolete tariff to the transitional general supply demand tariff, the general supply demand tariff or the general supply STOU tariff by the end of the TSS period. Over time, the obsolete general supply TOU tariff will be increased relative to the cost-reflective tariff options.

In 2019/20 it is expected that over 90% of customers will be better off by moving to one of the cost-reflective tariff options.

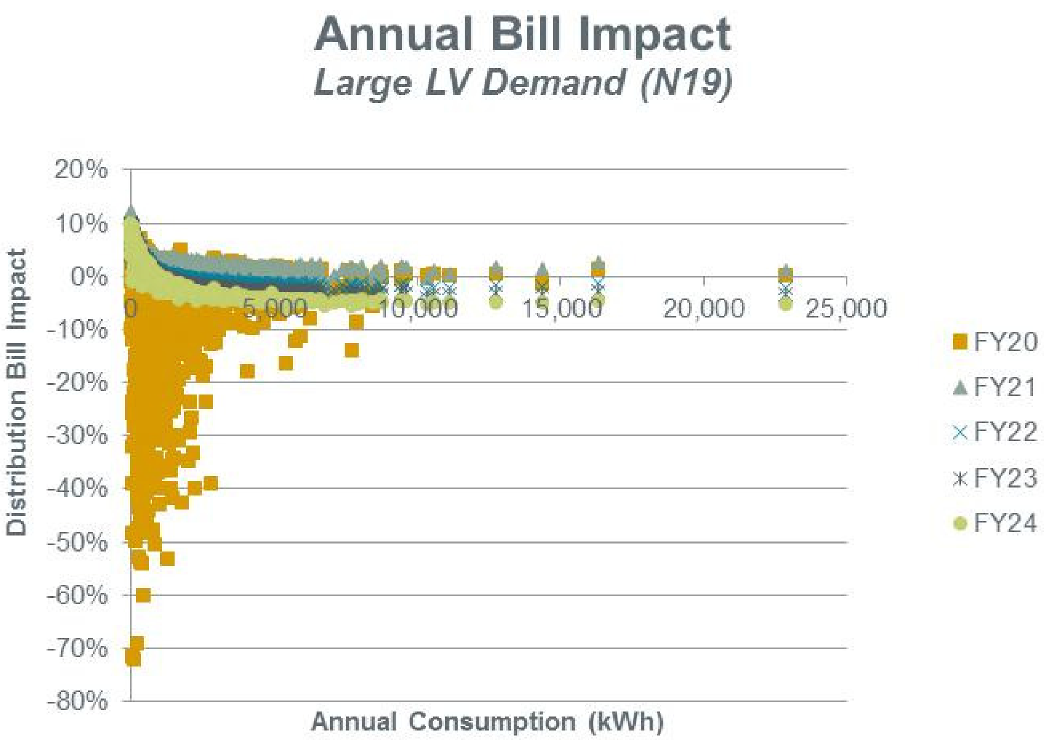
3. Low voltage demand

The figure below illustrates the expected distribution network bill impacts for large LV demand tariff customers. Bill impacts include estimated CPI of 2.4% and are set using our smoothed annual revenue requirement as proposed in our Revised Regulatory Proposal.

The 2019/20 estimates are impacted by the following changes to the structure of this tariff:

- replacing our 1pm to 8pm demand charging window with a 4pm to 8pm demand charging window; and
- changes to those months defined a high season and low season.

Figure 41 – Illustrative annual increase in distribution network bill – large LV demand tariff (N19)



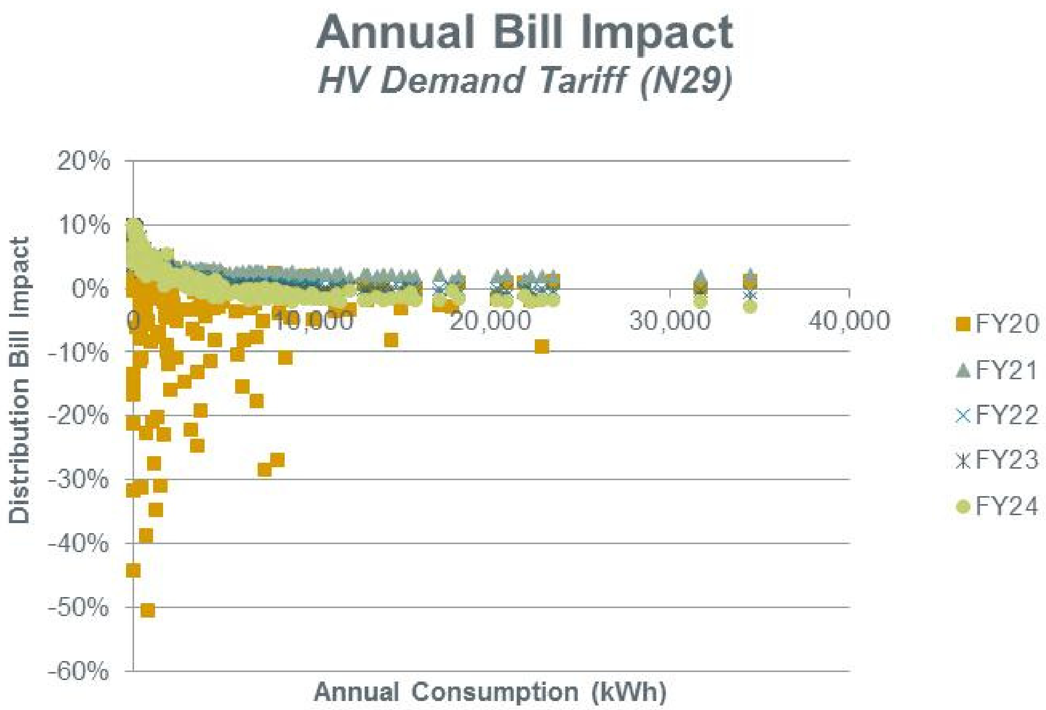
4. High voltage demand

The figure below illustrates the expected distribution network bill impacts for HV demand tariff customers. Bill impacts include estimated CPI of 2.4% and are set using our smoothed annual revenue requirement as proposed in our Revised Regulatory Proposal.

The 2019/20 estimates are impacted by the following changes to the structure of this tariff:

- replacing our 1pm to 8pm demand charging window with a 4pm to 8pm demand charging window; and
- changes to those months defined a high season and low season.

Figure 42 – Illustrative annual increase in distribution network bill – HV demand tariff (N29)



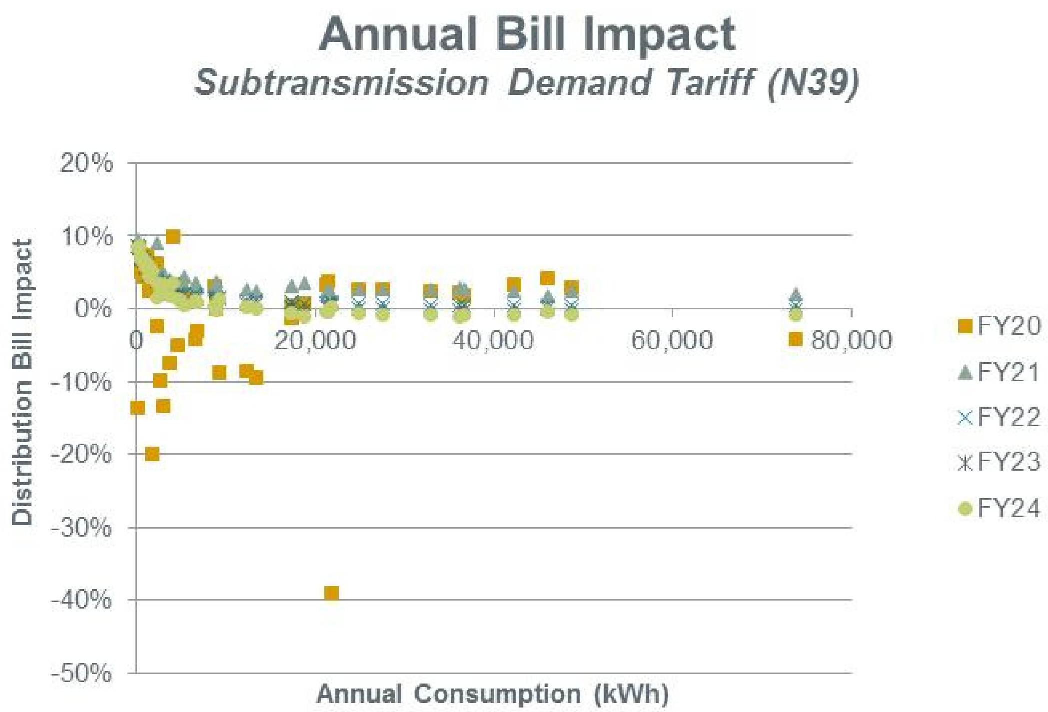
5. Subtransmission demand

The figure below illustrates the expected distribution network bill impacts for Subtransmission demand tariff customers. Bill impacts include estimated CPI of 2.4% and are set using our smoothed annual revenue requirement as proposed in our Revised Regulatory Proposal.

The 2019/20 estimates are impacted by the following changes to the structure of this tariff:

- replacing our 1pm to 8pm demand charging window with a 4pm to 8pm demand charging window; and
- changes to those months defined a high season and low season.

Figure 43 – Illustrative annual increase in distribution network bill – ST demand tariff (N39)



Appendix 11: Compliance checklist

This section sets out the TSS Rule requirements and the section in which those requirements have been met within this document.

Table 27 – Compliance checklist

Rule Provision	Amending Clause	Requirement	Relevant section
Part E: Regulatory proposal and proposed tariff structure statement			
6.8.2		**Submission of tariff structure statement**	
6.8.2(a)	11.73.2(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*.	Noted
6.8.2(b)	11.73.2(a)	A *regulatory proposal* and a proposed *tariff structure statement* must be submitted: by 27 November 2015	Noted
6.8.2(c)	11.73.2(a)	A proposed *tariff structure statement* must be accompanied by information that contains a description (with supporting materials) of how the proposed *tariff structure statement* complies with the *pricing principles for direct control services.*	Chapter 7
6.8.2(c1a)	11.73.2(a)	The proposed *tariff structure statement* must be accompanied by an overview paper which includes 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	Not applicable to revised proposal
6.8.2(d1)		The *tariff structure statement* must be accompanied by an *indicative pricing schedule*.	Appendix 9
6.8.2(d2)		The *tariff structure statement* must comply with the *pricing principles for direct control services*.	Chapter 7
6.8.2(e)		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 *tariff structure statement* are to be submitted for each *distribution system*.	Not applicable
6.8.2(f)		If, at the commencement of this Chapter, different parts of the same distribution *system* were separately regulated, then, unless the *AER* otherwise determines, a separate *tariff structure statement* are to be submitted for each part as if it were a separate *distribution system*.	Not applicable
Part I: Distribution Pricing Rules			
6.18.1A		**Tariff Structure Statement**	

Rule Provision	Amending Clause	Requirement	Relevant section
6.18.1A(a)(1)		The *tariff structure statement* must include the *tariff classes* into which *retail customers* for *direct control services* will be divided during the relevant *regulatory control period*.	Section 6.1.1
6.18.1A(a)(2)		The *tariff structure statement* must include 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).	Appendix 2 Chapter 6
6.18.1A(a)(3)		The *tariff structure statement* must include the structures for each proposed tariff.	Appendix 3 and 4
6.18.1A(a)(4)		The *tariff structure statement* must include the *charging parameters* for each proposed tariff.	Appendix 3
6.18.1A(a)(5)		The *tariff structure statement* must include a description of the approach that the *Distribution Network Service Provider* will take in setting each tariff in each *pricing proposal* during the relevant *regulatory control period* in accordance with clause 6.18.5 (pricing principles).	Chapter 7, Appendix 5, 6, 7, 8 and 10
6.18.1A(b)		The *tariff structure statement* must comply with the *pricing principles for direct control services*.	Chapter 7
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*.	Appendix 9

Rule Provision	Amending Clause	Requirement	Relevant section
6.18.3		**Tariff Classes**	
6.18.3(b)		Each customer for *direct control services* must be a member of 1 or more *tariff classes*.	Section 6.1.1 and 6.1.2

Rule Provision	Amending Clause	Requirement	Relevant section
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 6.1.1 and 6.1.2
6.18.3(d)		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 6.1.1
6.18.4		**Principles governing assignment or re-assignment of retail customers to tariff classes and assessment and review of basis of charging**	
6.18.4(a)		In formulating provisions of a distribution determination governing the assignment of *retail customers* to *tariff classes* or the re-assignment of *retail customers* from one *tariff class* to another, the AER must have regard to the following principles:	Noted
6.18.4(a)(1)		*retail customers* should be assigned to *tariff classes* on the basis of one or more of the following factors: the nature and extent of their usage; the nature of their connection to the network; 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;	Section 6.1.1 and 6.1.2
6.18.4(a)(2)		retail customers with a similar connection and usage profile should be treated on an equal basis;	Section 6.1.1 and 6.1.2
6.18.4(a)(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;	Section 6.1.1

Rule Provision	Amending Clause	Requirement	Relevant section
6.18.4(a)(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. **Note:** If (for example) a customer is assigned (or reassigned) to a tariff class on the basis of the customer's actual or assumed maximum demand, the system of assessment and review should allow for the reassignment of a customer who demonstrates a reduction or increase in maximum demand to a tariff class that is more appropriate to the customer's load profile.	Section 6.1.1 and 6.1.2. Appendix 2
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.	Appendix 2
6.18.5		**Network Pricing Principles** **Principles governing assignment or re-assignment of retail customers to tariff classes and assessment and review of basis of charging**	
		Network Pricing Objective	
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 6 and 7
		Application of the Pricing Principles	
6.18.5(b)		Subject to paragraph (c), a *DNSP's* tariffs must comply with the pricing principles set out in paragraphs (e) to (j).	Chapter 7
6.18.5(c)		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: to the extent permitted under paragraph (h); and to the extent necessary to give effect to the pricing principles set out in paragraphs (i) to (j).	Chapter 7 and Appendix 9
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*.	Chapter 7
		Pricing Principles	

Rule Provision	Amending Clause	Requirement	Relevant section
6.18.5(e)		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.	Section 7.4 and Appendix 5
6.18.5(f)		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.	Section 7.5 and Appendix 6
6.18.5(g)		The revenue expected to be recovered from each tariff must: 1. reflect the Distribution Network Service Provider's total efficient costs of serving the retail customers that are assigned to that tariff; 2. when summed with the revenue expected to be received from all other tariffs, permit the Distribution Network Service Provider to recover the expected revenue for the relevant services in accordance with the applicable distribution determination for the Distribution Network Service Provider; and 3. comply with sub-paragraphs (1) and (2) in a way that minimises distortions to the price signals for efficient usage that would result from tariffs that comply with the pricing principle set out in paragraph (f).	Section 7.2 and 7.6 Appendix 7 and 8

Rule Provision	Amending Clause	Requirement	Relevant section
6.18.5(h)		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 7.7 and Appendix 10
6.18.5(i)		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
6.18.5(j)		A tariff must comply with the *Rules* and all *applicable regulatory instruments*.	Noted

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Publication date
January 2019

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