Ergon Energy TSS Explanatory Notes 2020 - 2025

June 2019

General Manager Customer, Brand & External Relations
11 Enterprise Street
BUNDABERG QLD 4670

Or via tariffs@energyq.com.au

Contents

1 BACKGROUND

These Explanatory Notes accompany our 2020-25 Tariff Structure Statement (TSS) submission to the Australian Energy Regulator (AER) on 14 June 2019.

The Explanatory Notes provide detailed information on our proposed network tariff structures and charges for the 2020-25 regulatory control period and how we comply with the National Electricity Rules (NER) and pricing principles. It also provides us an opportunity to comment on its network tariff strategy and how our work will shape future network use.

1.1 Guide to this Explanatory Note

This Explanatory Notes document provides support and context to the TSS document. The TSS outlines our proposed tariff classes, tariff structures, charging parameters and indicative tariff levels, and demonstrates compliance with pricing principles.

However, the development of the 2020-25 TSS has coincided with a period of significant change in the way in which customers use our distribution network and the expectations customers have of the network services we provide. To ensure our network tariffs remain relevant into the future, we need to start considering the future network tariff structures that will be required to meet the evolving needs and expectations of our customers.

We consider that future network tariffs will be capacity-based. Capacity-based tariff structures are very relevant in an environment where the low-voltage network is evolving to become an active network that will, for example, support greater levels of roof-top solar and other forms of home load management technologies and markets (eg. batteries, peer-to-peer trading).

We recognise that capacity-based tariffs are significant evolution from the suite of network tariffs currently on offer, particularly to small customers. Many small customers are unfamiliar with the concept of capacity tariffs, and given this we consider it important to start taking customers on a journey towards these more cost-reflective future tariff structures during the 2020-25 regulatory control period.

Since our initial TSS in January 2019, we have developed three network tariff options for our Standard Asset Customers (SAC) to assist their transition to future capacity-based cost-reflective tariffs.

We have also developed primary and secondary broad-based load control tariffs for larger business customers, and primary load control tariffs for small business customers. During the TSS engagement in 2018 the value of load control was noted by a number of customer segments, and our proposed tariff options seek to incorporate this feedback while offering customers additional choice and control options that suit their particular need.

1.2 How to read this document

Section 2 of these Explanatory Notes provides a strategic view of network tariff options and the need to identify a default tariff for the 2020-25 regulatory control period to ensure we maintain the momentum of our proposed network tariff reforms. The remainder of this document offers additional explanatory information in support of the 2020-25 TSS.

Chapter 3 sets out how our network tariff strategy is an integral part of the Energy Queensland corporate strategy, how the stakeholder engagement process undertaken as part of preparing the

2020-25 TSS aligns with its customer strategy, and how the proposed tariffs and tariff structures have been developed to complement our network planning and Demand Management (DM) strategies.

Finally Chapters 4 to 7 provide additional information in support our 2020-25 TSS.

1.3 Next steps and on-going consultation

We submitted our initial TSS in January 2019. The TSS was supported by an Explanatory Notes document which outlined tariff structures based on a capacity-based paradigm and laid the foundation for development of capacity-based tariffs. It was acknowledged that capacity-based tariffs are a significant evolution from the suite of network tariffs currently on offer, particularly to small customers.

This updated June 2019 TSS consolidates the current state in our capacity tariff suite development and the initial positions presented in January 2019. We believe we have made significant progress in converging toward the Revised TSS submission in December 2019. We have received feedback through the consultations we have undertaken since January 2019 and anticipate that further tariff development responses will be required as a result of customer insights and proposals emerging from the AER consultation process. Any TSS changes are expected to maintain the strategic framework in which the current tariff strategy has been developed while responding to customer feedback and ensuring TSS compliance.

As examples of areas of possible evolution, recent customer feedback has canvassed options to refine the Basic tariff structure, tariff assignment alternatives (eg. options that minimise customer tariff transfers and implementation cost implications), capacity tariff simplification and implementation pathways and the integration of controlled load across the capacity tariff suite.

The AER will consult on our updated TSS with us during July and August 2019, and publish its draft Distribution Determination by September 2019. We will then submit a Revised TSS to the AER by December 2019. The AER will also consult on its draft Distribution Determination and our Revised TSS before publishing its final Distribution Determination by April 2020. We encourage our communities and customers to make submissions to the AER as part of its consultation processes.

After the AER publishes its Distribution Determination, we will prepare our distribution network charges for the 2020-21 regulatory year, commencing 1 July 2020.

In the meantime, we will continue to engage with our customers and other stakeholders on this TSS, including through our Customer Council and our website, www.talkingenergy.com.au, where all of our existing consultation material is available. Questions can also be directed to us via tariffs@energyq.com.au.

2 OVERARCHING TARIFF STRATEGY

The role of the network is evolving from the safe and reliable distribution of energy, to an enabler of an ecosystem of distributed energy resources. Throughout our consultation, we have heard how customers are choosing to use our network in many different ways. Combined with emergent technology shifting network utilisation patterns, our existing tariffs no longer enable a fair recovery of network costs or provide the flexibility and choices expected by our customers.

In the longer term, we anticipate an increase in the relevance of capacity-based tariffs in support of emergent technology and new customer needs in the future, supported by load control tariffs and broad-based and locational demand management programs.

We consider that the 2020-25 TSS needs to begin that transition, catering for diverse customer needs through a mix of innovative cost-reflective tariff options that include time-of-use demand and capacity tariffs, and simple and attractive load control tariffs. Customers assigned to cost-reflective network tariffs will benefit from the pass through of substantial revenue reductions in the first year of the regulatory control period.

2.1 Mandate for Tariff Reform

The structures of most of our network tariffs were developed in the early 1990s - a period when distribution networks supported a one-directional supply of electricity from generators to customers, and electricity tariffs assumed that all customers accessed the network in the same fashion.

Technology advances (like solar panels, home batteries, digital meters), the emergence and increased adoption of energy intensive appliances (like air conditioners and pool pumps), transport advances (such as electric vehicles), a growing population, greater household incomes, regionalisation, the emergence of aggregators and technology platforms where energy can be traded, and (generally) higher standards of living, all contribute to the current situation whereby customers are no longer accessing and utilising our electricity networks the way they used to. These are societal/environmental factors.

Also, as a customer-centric organisation, we listen to our customers, who, in relation to our networks and the cost to use our networks, are telling us that:

- They expect us to ensure equity of access to electricity
- They support tariff reform and greater cost reflectivity
- They want greater choice in their tariff options and control over their electricity supply
- They are concerned about affordability
- They need us to keep our tariffs as simple as possible.

Customers are of the view that our existing legacy network tariffs embody cross-subsidies, in many cases they do not reflect the true cost of supplying electricity (especially in periods of peak demand), and there are few choices available. However, customers are also concerned about a smooth transition to cost reflectivity and have acknowledged the fact that the tariff reform journey may require intermediate steps and transition periods before reaching the desired outcomes.

2.2 Our current position (2020-25 TSS)

Our tariff reform journey started in 2015 with seasonal time-of-use energy and demand-based tariffs progressively being made available to our residential and business customers. These tariffs have had limited mass-market adoption, in part due to the majority of small customers having basic meters and the limited exposure of these tariffs to the retail market.

Our 2020-25 TSS reflects the following actions we propose to take in advancing towards a cost-reflective tariff future. We propose to:

- Introduce a suite of new demand and capacity tariffs for LV customers
- Adopt both an evening window of 4-9 pm and a daytime window of 10am-4pm for capacity charging of the proposed Basic and Capacity tariffs for LV customers
- Not signal seasonal network constraints in new tariffs
- Change our tariff assignment policy
- Provide increased incentives for existing network load control tariffs
- Offer three new load control tariffs to business customers.

2.3 Future State – Capacity-based Tariffs (2025 and beyond)

The drivers of network investment are changing and expanding. This expansion includes the challenge to integrate large amounts of Distributed Energy Resources (DER) into the network, investment to maintain network voltage and power quality performance as well as declining levels of traditional augmentation where network capacity is exceeded. Our tariffs need to develop in line with these changes and remain relevant as the electricity supply market continues to evolve.

Under this scenario there would be a bias towards the network charging on the basis of providing adequate capacity rather than charging on the basis of signalling network peak demand constraints. The peak demand response remains an important consideration but accommodating these new business drivers needs to be integrated into our future network tariff development.

We will offer capacity-based tariff for residential and small business customers during the 2020-25 regulatory control period on an opt-in basis, and will continue to engage with stakeholders on options to enable capacity tariff adoption for customers with basic meters.

2.4 Key elements of our 2020-25 tariff strategy

Integrating network cost drivers into cost-reflective network tariff structures that are compliant with the NER leads to demand/capacity-based, time-of-use and day-of-week network tariffs. Currently almost all of our residential and small business mass-market customers are assigned to network tariffs that consist of a daily charge plus a rate for energy consumption irrespective of when the consumption occurred.

In the 2017-20 TSS, we introduced first generation cost-reflective tariffs to mass-market customers as part of complying with the new NER requirements. Key market feedback on these demand tariffs has been that:

- Customers were challenged by the concept of demand, particularly when overlaid with other complexity in language and determining billable quantities
- Retailers found it a challenge to get customers comfortable with these first-generation time-of-use demand tariffs and to adopt them
- Stakeholders struggled to communicate this reform as a step forward

Despite the challenges, the NER has firmly put the electricity market on a pathway where networks need to be pricing distribution network services into the market (and particularly to retailers) on a basis that reflects the Long Run Marginal Cost (LRMC) and that signals optimal and efficient usage of the network.

Successful implementation of our 2020-25 network tariff strategy will:

- Reduce cross-subsidies between customer classes
- Minimise uneconomic investment in solar PV and other emerging technologies
- Improve network capability to manage network cost issues through load management
- Contribute to an increase in network utilisation through the reduction in peak demand and increase in minimum demand
- Delay or defer network investment in augmentation, power quality and voltage management.

2.5 Pace of tariff reform

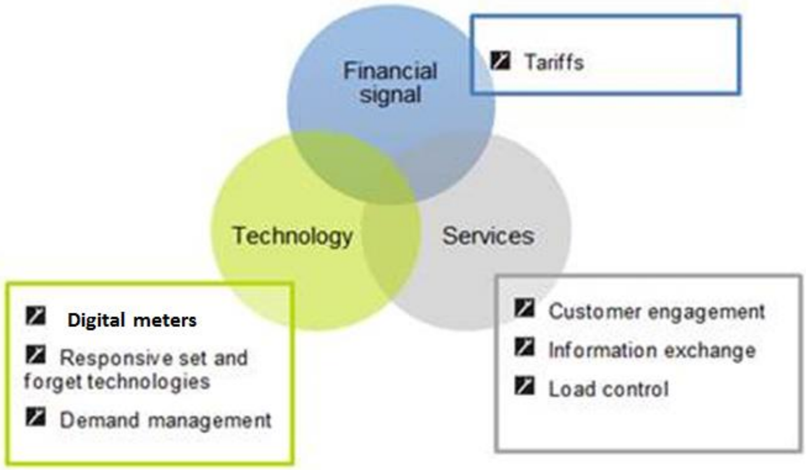
In considering the implementation of our network tariff strategy, we have taken into account the market conditions, the availability of digital meters to mass-market customers, the impact of tariff reform on customers and feedback provided by stakeholders as part of our engagement process. Advocates have noted timely access to digital metering (or equivalent technology) as a barrier to the uptake of cost-reflective tariffs. They have also confirmed the need for customer education and information as key elements to accelerate tariff reform.

For these reasons and in particular because of the potential customer impacts from moving existing customers to cost-reflective tariffs, we have included opt-out provisions for customers enrolled in retailer hardship programs, and consider a voluntary introduction of capacity tariffs for residential and small business customers is the most suitable approach at this time.

2.6 Market Conditions

The success of our network tariff reforms lies at the point where the network tariff signals are matched with the provision of services to customers and the availability of a range of enabling technologies. The introduction of cost-reflective (demand or capacity-based) network tariffs will enable customers to benefit from new technological developments, product innovation and behavioural changes. Figure 1 illustrates the new market environment in which network tariff reform is only one element of the value chain.

Figure 1 - Market environment



We recognise that the implementation and success of network tariff reform will only happen through a coordinated market approach and the active engagement of a wide range of stakeholders, including electricity retailers, customers, customer advocacy groups and government agencies. It is also reliant on the uptake of new technology such as digital metering.

We acknowledge that the design of network tariffs requires careful consideration to avoid signalling demand too sharply leading to bill shock.

3 TARIFF AND CORPORATE STRATEGY ALIGNMENT

Our commercial sustainability is dependent on successfully navigating the challenges posed by emerging technologies, falling electricity consumption and fundamental changes in the way customers use the distribution network. Network tariffs are a critical component of our response to these challenges by providing customers with more cost-reflective signals. This will improve fairness by reducing cross-subsidies and costs by putting downward pressure on network investment over the longer term through rewarding customer responses to these signals.

We recognise the pivotal role network tariff reform plays within the wider business. For this reason, our network tariff strategy has been carefully developed with a view to align with its corporate strategy, customer strategy and DM strategy in order to achieve more efficient outcomes and meet customer expectations. Such a coordinated approach will ensure we will deliver our commitment to provide services our customers need.

3.1 Corporate strategy

As part of the Energy Queensland Group, we have developed a strategic framework that lays the foundation for us to be a more agile, innovative and responsive participant in the ever changing energy market environment.

Our proposed network tariff strategy supports Energy Queensland's vision to Energise Queensland Communities by enabling its purpose in safely delivering secure, affordable and sustainable energy solutions with our communities and customers.

Energy Queensland's over-arching strategic framework is depicted in Figure 2 below.

Figure 2 - Energy Queensland's Strategic Framework

3.2 Interaction between tariff strategy and customer strategy

Our tariff strategy, in its simplest form, is underpinned by a move from volume-based to cost-reflective network tariffs. This can occur upon the acceptance of our strategy by our customers and stakeholders and will be enabled by optimising the technology and regulatory contexts. We know this will be a journey that requires co-operation between us and the whole industry and that the journey must begin now to ensure everyone benefits in the medium to long-term.

Network tariff reform sits in the broader context of our Customer Strategy in delivering success for both our customers and our business. Our goal is to deliver valued experiences based on a foundation of knowledge and understanding the diversity of needs across all of our customers.

Our Customer Principles and their relationship to our Tariff Strategy are outlined in Table 1 below.

Table 1 - Customer Principles

Customer Principle	Relationship to Tariff Strategy
Know our Customers	• We have consulted widely with customers on the proposed suite of tariffs in our 2020-25 TSS, and we will continue to seek customer feedback via tariff trials we will conduct in the lead-up to 2020 and through exploring further tariff options during the 2019 TSS consultation period.
Deliver Value	• Our goal is to provide customers with a selection of tariffs they can utilise to best optimise their relationship with electricity. As the industry, tariffs and customer behaviours develop, our strategy is to further develop our tariff suite to create further opportunities for customers to participate in the market as we progress towards cost-reflective network pricing. • We want to ensure network tariffs promote efficient use of the network that will deliver sustainable outcomes for customers.
Make it Easy	• Our goal is to develop tariffs that are easily understood by customers and retailers, and can be responded to in maximising customer value.

3.3 Interaction between tariff strategy, DM and network planning

Our network planning, DM and tariff strategies share a common goal: to transform our network into a multi-directional, multi-embedded, multi-technology network platform of the future. In managing our augmentation expenditure (Augex), we deliver prudent and efficient non-network and market driven solutions. As opposed to traditional network solutions, the use of these alternatives provides increased optionality and ensures our investment choices are optimised for a wide range of possible futures.

Important parts of this work include:

- Forecasting future total and peak load both on a system-wide basis and on geographical/network topography basis
- Identifying and implementing non-network alternatives to avoid the need for additional network infrastructure.

Forecast and actual peak load is currently a key driver of Augex. Whilst in the future we anticipate Augex will not be heavily driven by seasonal customer demand, if we are to continue to reduce network tariffs in real terms, we must look at a variety of avenues to manage load.

Our two primary vehicles in achieving this objective are to continue to implement DM strategies and to introduce cost-reflective network tariffs.

DM is an integral part of our approach to forecasting, planning and developing tariff, intelligent grid and customer strategies. DM involves working closely with end use customers and industry partners to selectively reduce demand with the intention of maintaining system reliability in the short term and deferring the need to build more ‘poles and wires’ over the longer term. We plan to support the introduction of network tariff reform with dynamic incentives that combine load control and locational demand management programs.

Our DM programs complement both a demand tariff scenario and a capacity tariff scenario providing a mitigant where network constraints or congestion would otherwise result in network investment. The DM programs and our network tariff strategy will work together in the following ways to help optimise network investment and bring down network costs for customers.

- We have around 202MW of load under ‘control’ via traditional load control tariffs. The demand reductions available from load control tariffs are factored into the demand forecast, thereby reducing network costs
- We also have around 2MW of load under control in relation to the PeakSmart air conditioning incentives program. This ‘control’ is exercised when required to manage peak demand but it is not always available where and in the quantities we need it
- In addition, with customers increasingly connecting DER such as solar photo-voltaic (PV) systems, batteries and Home Energy Management Systems (HEMS) to our network, we anticipate demand response services from DER will become increasingly available. As customers transition away from load control tariffs, demand response procured from the market (for example, via customer incentives) will make up a growing proportion of our demand response portfolio
- We believe that there is significant potential for shifting ‘troughs’ in demand. This would provide improvements in network utilisation and reduction in power quality issues with minimal customer impact. Traditionally the audio frequency load control (AFLC) program has been used to reduce system peak demand. With the ‘solar sponge’ initiative, we are now trialling an alternative switching program whereby electric storage for hot water systems on control load tariffs are used as a ‘solar sponge’ to integrate renewables into the network.

4 NETWORK TARIFFS

4.1 Recovering costs

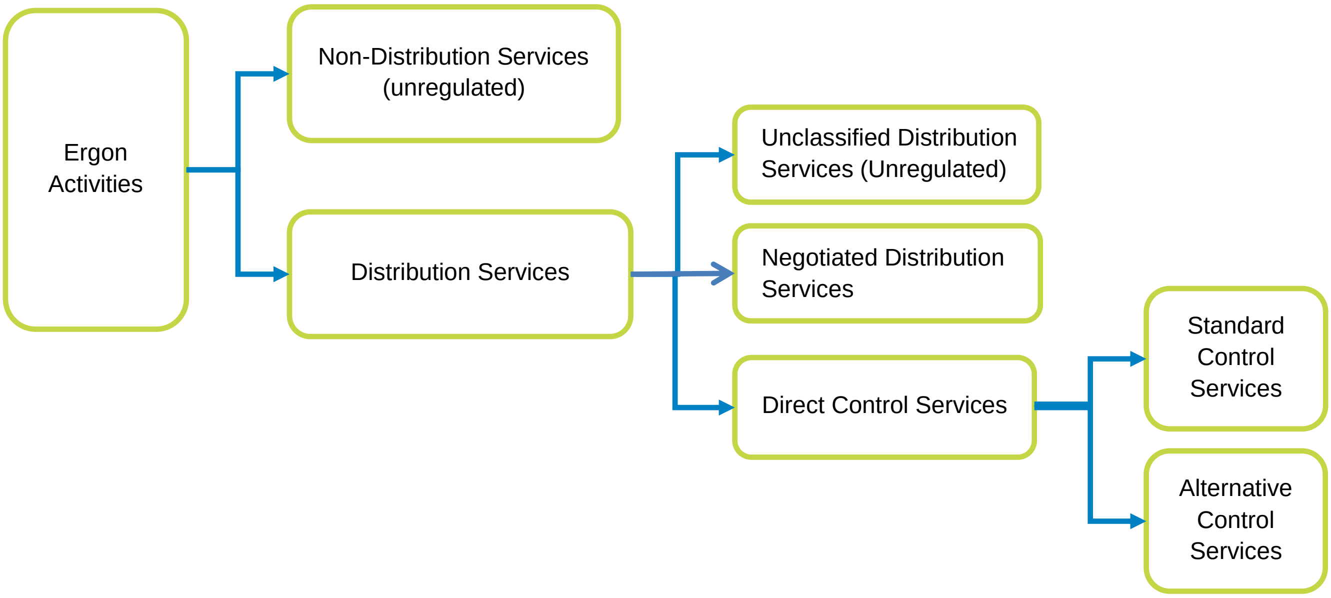
The AER determines how our distribution services are classified and in turn the nature of the economic regulation. This is important as it determines how tariffs will be set and how charges are recovered from customers.

Services incorporated within the customer's electricity bill relate to services that are central to electricity supply using our poles and wires. These services, classified as Standard Control Services (SCS) in accordance with the AER's Framework and Approach (F&A), relate to the access and supply of electricity using our poles and wires (distribution system) to customers. Specifically, they include network services (eg. construction, maintenance and repair of the distribution system) and some connection services (eg. small customer connections).

Customer specific or customer-requested services, classified as Alternative Control Services (ACS), are charged separately. ACS are comprised of ancillary services, some connection services, type 6 metering services and public lighting services in accordance with the F&A.

Our TSS relates to the tariffs for those distribution services classified by the AER as direct control services (SCS or ACS) as shown in the Figure 3 below.

Figure 3 - Classification of Ergon Energy's distribution services



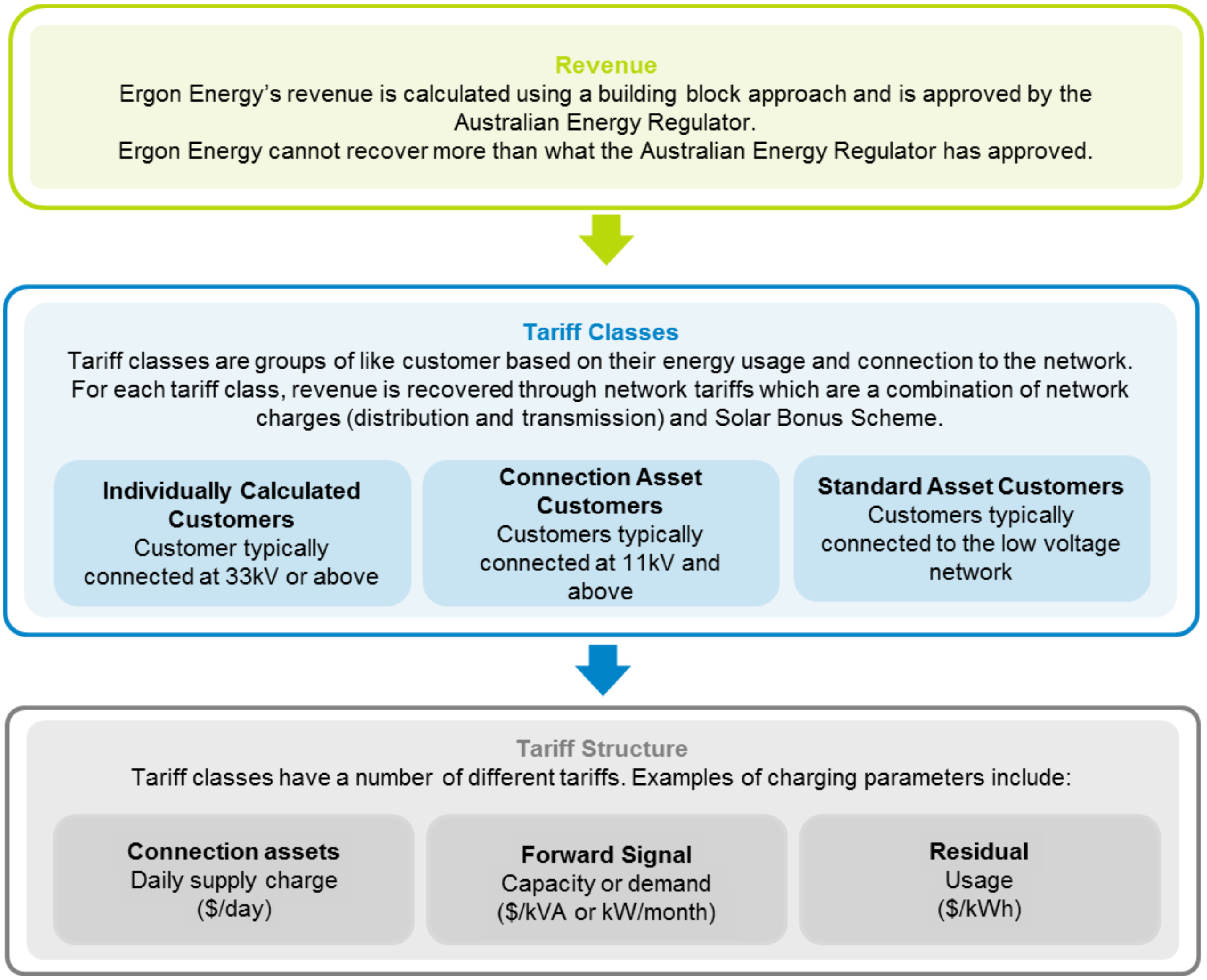
There are three primary sources of revenue that we recover through network use of system (NUOS) charges:

- Distribution Use of System (DUOS) revenue
- Recovery of Jurisdictional Scheme amounts
- Designated Pricing Proposal Charge (DPPC) (transmission network) revenue.

We recover our allowed revenue through network tariffs in a way that is consistent with the pricing principles set out under the NER. The tariff structures outlined in the TSS do not affect how much revenue we can earn. Instead, they determine how much revenue is recovered from particular customer groups.

We charge NUOS charges to electricity retailers. Customers may not see our network charges itemised on their retail electricity bill, as the retailer may incorporate our network charges into their retail prices and charges, along with other costs of producing and supplying electricity. In 2018-19, network costs comprised approximately 38 per cent of the bill for a small customer.[1] Our allocation of allowed revenue is illustrated in Figure 4 below.

Figure 4 - Ergon Energy allocation of its allowed revenue to its tariff classes and tariffs



Further to these NUOS charges, additional charges may apply where a customer requests the provision of specific or one-off services (such as special meter reads or disconnections). The level of charges we can apply for these services, known as ACS, are regulated by the AER.

4.2 Our network tariff components

Our network tariffs are underpinned by key concepts, including tariff classes, tariff structures, and charging parameters and levels.

The following sections provide further explanation of these concepts as they apply to us.

[1] Queensland Competition Authority's Regulated Retail Electricity Prices for 2018-19, May 2018.

4.2.1 Tariffs and tariff classes

We have over 750,000 residential and business customers, with a range of different characteristics. We group customers that have similar characteristics together so that similar customers are assigned to the same tariffs that are available under their tariff class.

At the broadest level, we differentiate between tariff classes based on the voltage level at which a customer is connected to its network and the amount of electricity that they consume annually.

The key voltage levels used for tariff setting purposes are the sub-transmission, high voltage (HV) and low-voltage (LV) levels of the network. The majority of our customers – residential and small business – are connected at the LV level of the network, with a relatively small number of large business customers connected at the sub-transmission or HV levels of the network.

4.3 Network tariff charging parameters

A network tariff may be made up of several separate charging parameters. The charging parameters that may be used when constructing network tariffs include the following:

- Daily supply charge (also known as fixed charge)
- Flat charge (also known as energy or volumetric charge)
- Time-of-use (ToU) energy charge
- Demand charge
- Excess demand charge
- Capacity charge (SAC Small)
- Capacity charge (ICC and CAC)
- Excess kVAr charge.

Depending on whether a network tariff is designed for large or small customers, these different charging parameters can also serve different purposes as explained further below.

4.3.1 Daily supply charge

The daily supply charge is a $ per day charge applied regardless of usage to each energised connection point.

There are a number of ‘fixed’ costs that we must recover for assets that have already been built and must be maintained for a long period of time. For small customers, daily supply charges are designed to recover costs associated with a customer’s connection to the network. Portions of the residual shared network costs are also collected through daily supply charges. In the case of the Capacity tariff, the fixed charge also recovers the cost of the capacity allowance embedded in the tariff. For large customers, daily supply charges reflect the costs associated with the connection and management of the customer.

4.3.2 Energy usage charge

Flat charge

This charge is calculated in cents or dollars per kilowatt hour ($/kWh) or dollars per month, depending on the tariff, and is applied to the total usage at a connection point. This charge recovers all or some of the costs that are not recovered from the daily/monthly supply charge. This charge remains the same regardless of the time of the day or month.

Inclining block charge

This charge is calculated in cents or dollars per kilowatt hour ($/kWh) with different increasing rates applying to blocks of electricity consumed during the billing period. This charge recovers all or some of the costs that are not recovered from the daily/monthly supply charge.

Time-of-use (ToU) charge

This charge is calculated in cents or dollars per kilowatt hour ($/kWh), depending on the tariff, with different rates applying to the electricity consumed at a connection point at different times of the day. For small customers, ToU usage charges can recover costs that have not been recovered from a demand charge or daily supply charge.

These charges are designed to incentivise the reduction of demand on the network during peak times by encouraging customers to switch non-essential electricity usage to off-peak and/or shoulder times.

4.3.3 Demand charge

Demand charges are levied on the basis that network users who place greater pressure on the network should incur higher charges.

Typically, this is a monthly charge calculated as a $/kilowatt (kW) or $/kilovolt ampere (kVA) rate for the maximum (or peak) demand recorded.

Generally, demand is metered at a customer’s connection point where the maximum demand placed on the distribution network at any time, or at a specific time, or within a specific time is recorded (traditionally in 30 minute intervals).

In the case of the new SAC Small demand tariffs, two different charging periods for daytime and evening time are embedded in the tariff structure. Specific demand charges apply to metered maximum demand in each period.

For larger customers (CAC and ICC) demand charging can be based on Authorised Demand (AD) which is determined either through contractual negotiation with the customer or determined as part of the annual network tariff setting process using historical data.

Demand charges deliver stronger user-pays pricing than a usage charge alone as it incorporates the incremental cost to support future capacity requirements.

4.3.4 Excess demand charge (SAC Large and CAC)

Represented as a rate ($) per excess kVA. The excess charge is measured as the single highest maximum demand outside the peak charging window minus the maximum demand during the peak period in the billing period. It only applies where the maximum demand outside of the period is higher than the maximum demand in the peak period.

4.3.5 Capacity charge (ICC and CAC)

This is a monthly charge calculated as a dollar per kilovolt ampere ($/kVA) rate for the amount of network capacity which is set aside for an individual customer to use at any time.

Capacity charges traditionally account for augmentation costs at the customer connection level and all associated upstream augmentation costs already incurred to provide sufficient network capacity to accommodate peak demand.

4.3.6 Capacity tariff demand charge (SAC Small)

The charge applies to the following primary tariffs:

- Residential Capacity
- Small business Capacity.

Capacity tariffs have access to a specified kW capacity level in both the day and evening periods included.

The capacity tariff demand charge applies to demand in the day and evening periods which exceeds the specified capacity. Customers can exceed their capacity level on three separate days in each month in each window without incurring the capacity tariff demand charge. Customers who exceed their capacity level during the day will pay for the highest exceedance at the day demand rate ($/kW per month). Similarly, customers who exceed their capacity level during the evening will pay for the highest exceedance at the evening demand rate ($/kW per month).

4.3.7 Excess kVAr charge

We introduced Excess kVAr billing for Individually Calculated Customers (ICC) in 2015-16. Because of the relatively large number of these customers that had embedded generators, a number of exceptions were needed and changes were made both to the kVA billing and the Excess kVAr billing processes in the following year:

- kVA charges were set to zero for intervals when kW was imported into the network
- Excess kVAr charges were based on exceedance of the permitted capacity at compliant power factor, rather than on the actual demand at compliant power factor.

We extended Excess kVAr billing to Connection Asset Customers (CAC) customers in 2017-18.

The Excess kVAr rate for customers is currently $4.00/kVAr/month. This was based on an assessment of the hurdle rate to induce customers to install power factor correction at their premises.

The objective of the Excess kVAr program was to reduce the incidence of non-compliance with the power factor provisions of the NER. It was intended to target only those customers that are non-compliant.

The modifications to the original charging process that were necessary to accommodate customers with embedded generation, primarily in changing the kVAr threshold from that allowable at a compliant power factor to the maximum at the customers' authorised demand, significantly reduced the incentive properties of this charge.

This is further highlighted by the relatively small quantum of the Excess kVAr charge we recover, which is now around $450,000 per annum, which is not material compared to the total revenue recovery of the CAC and ICC user groups.

Added to this, it is apparent that since the introduction of kVA billing there has been a steady improvement in the average power factor, as customers adapt to the new charging regime and take steps to minimise their demand charges.

In view of the above analysis and the desire to align network tariffs across the Queensland distribution networks we consulted with customers on the opportunity to retire the Excess kVAr charge from 1 July 2020. Alternative views were expressed by customers but the majority of feedback agreed with retirement of the charge.

Accordingly, we propose to retire the excess kVAr charge from July 2020.

5 RATIONALE FOR THE SCS TARIFF CLASSES, TARIFF IMPLEMENTATION AND TARIFF STRUCTURES

This chapter explains the reasons for the proposed tariff classes, tariff implementation and tariff structures for SCS over the 2020-25 regulatory control period.

5.1 Tariff classes

Under chapter 10 of the NER, tariff classes are defined as 'a class of customers for one or more direct control services who are subject to a particular tariff or particular tariffs'. All customers who take supply from us for direct control services are a member of at least one tariff class.

Our tariff classes group retail customers on the basis of the nature of connection in accordance with clause 6.18.4 of the NER. Further, in accordance with clause 6.18.3(d) of the NER, our tariff classes group retail customers together on an economically efficient basis and to avoid unnecessary transaction costs.

In the 2017-20 TSS, the AER approved the following tariff classes:

Table 2 – AER approved tariff classes in 2017-20 TSS

Tariff Class	Customer connections	East	West	Mount Isa
ICC	ST, HV, LV	✓ (a)		
CAC	ST, HV, LV	✓	✓	✓ (a)
EG	EG ST, HV	✓	✓	✓ (a)
SAC Large	HV, LV	✓	✓	✓
SAC Small	LV	✓	✓	✓
SAC unmetered	Unmetered	✓	✓	✓
(a) There are presently no customers in these tariff classes in Mount Isa Region.				

Where ST represents the 110kV, 132kV, 66kV and 33kV voltage levels, and HV represents the 11kV and 22kV voltage levels.

Given the complexity of the current tariff class suite due to the inclusion of regional distinctions it is proposed to rationalise tariff class arrangements within our network. The proposed set of tariff classes shown below demonstrates a greater level of rationalisation and alignment of tariff classes for the 2020-25 regulatory control period:

Table 3 - Proposed Tariff Classes for 2020-25

Tariff class	Ergon Energy		
	East	West	Mount Isa
ICC	✓		
CAC	✓	✓	✓
SAC	✓	✓	✓

Where:

- SAC are customers typically connected at the LV network
- CAC have network coupling at ST or HV (66kV, 33kV, 22kV, 11kV) for East, West and Mount Isa, and
- ICC are customers coupled to the network at 110kV 66kV 33kV 22kV.

From 1 July 2020, we are proposing to remove the Embedded Generator (EG) tariff class. We are of the view that such a change would have the following advantages:

- The proposed tariff class structure is designed to align with the voltage level of a customer's connection to the network and will result in a more simple tariff class assignment process
- It will more closely align our tariff class structure with that of Energex, resulting in a more consistent tariff class assignment process across Queensland
- It will reduce unnecessary transaction costs as a result of fewer tariff classes to manage, and
- It aligns with the LRMC calculation at a voltage level.

EGs coupled at 33kV and above will be allocated to the ICC tariff class and receive site specific pricing. EGs connected at 11kV will be allocated to the CAC tariff class and will continue to access their existing tariff.

It is noted that in 2015 the AER accepted Energex's proposal to consolidate its tariff classes as part of the 2015-20 regulatory proposal.

5.2 Implementation of tariffs

Under the proposed arrangements, existing customers on legacy tariffs will be minimally impacted. Current legacy tariffs that are retained as default tariffs will be accessible to all customers. It is proposed that customers that have accessed a retail transitional tariff post 1 July 2017 can opt in to grandfathered network tariffs from 1 July 2020.

Our network tariff implementation strategy for the 2020-25 regulatory control period is summarised below.

ICC tariff implementation strategy

The tariff in the ICC tariff class is cost-reflective and no further changes are proposed.

The 2020-25 ICC tariff class definition will include scope for CAC customers to be classified and priced as ICC customers where there are significant deviations from typical kVA rates (at our discretion).

CAC tariff implementation strategy

The current suite of anytime demand tariffs are proposed to be retained for all existing and new customers, however the existing seasonal time-of-use demand tariffs are proposed to be retired on 1 July 2020.

Additionally, as part of the 2020-21 CAC rate setting process it is proposed to undertake an analysis of outliers in terms of cost per kVA outcomes with a view to considering reclassification to an ICC.

Table 4 - CAC tariff implementation strategy

Tariff	2020-25 Status	Availability
CAC 66kV	Default	New and existing customers
CAC 33kV	Default	New and existing customers
CAC 22/11kV Bus	Default	New and existing customers
CAC 22/11kV Line	Default	New and existing customers

Tariff	2020-25 Status	Availability
Note: This applies across the East, West and Mount Isa pricing zones.		

SAC Large tariff implementation strategy

It is proposed that the current suite of anytime demand tariffs be retained for all existing and new customers, with the existing seasonal time-of-use demand tariffs to be retired on 1 July 2020 as these will be superseded by the proposed time-of-use demand tariff. In addition, we are proposing to introduce primary and secondary load control tariffs for SAC Large, as well as a time-of-use energy tariff for customers who have utilised a transitional retail tariff since 1 July 2017

Table 5 - SAC Large tariff implementation strategy

SAC User Group	Tariff	2020-25 Status	Availability
SAC Large	Demand Large	Opt in	New and existing customers
	Demand Medium	Opt in	New and existing customers
	Demand Small	Opt in	New and existing customers
	Time-of-use Demand	Default	New and existing customers
	Time-of-use - energy	Grandfather	Existing retail transitional tariff customers
	Load Control Tariff A	Opt in	New and Existing Customers
	Load Control Tariff B	Opt in	New and Existing Customers
Note: This schedule applies across our East, West and Mount Isa pricing zones.			

SAC Small Residential and SAC small business tariff implementation strategy

We are introducing new tariff options for SAC Small residential customers in 2020-25. These include the Residential Basic tariff for existing customers with basic meters, and the Residential Demand and Residential Capacity tariffs for new customers with a type 1-4 meter. The existing inclining block tariff (IBT) will remain available for financially impacted customers to opt out to after having been defaulted to the Residential Demand tariff.

We are also introducing a similar set of new tariff options for SAC Small business customers in 2020-25. These include the Small Business Basic tariff for existing customers with basic meters, and the Small Business Demand and Small Business Capacity tariffs for new customers with a type 1-4 meter. The existing IBT will remain available for financially impacted customers to opt out to after having been defaulted to the Small Business Demand tariff. Further all new and existing business customers will have access to the primary and secondary load control tariffs.

Table 6 - SAC Small tariff implementation strategy

SAC User Group	Tariff	2020-25 Status	Availability
SAC Small Residential	Residential Capacity	Opt in	New and Existing Customers with Type 1-4 metering

SAC User Group	Tariff	2020-25 Status	Availability
	Residential Demand	Default	New and Existing Customers with Type 1-4 metering
	Residential Basic	Default	Existing customers with basic meters
	IBT Residential	Opt in for financially impacted customers only	New and Existing Customers
	Seasonal ToU Energy	Grandfather	Existing Customers
	Seasonal ToU Demand	Retired	Customers transferred to Residential Demand
SAC Small Business	Small Business Capacity	Opt in	New and Existing Customers with Type 1-4 metering
	Small Business Demand	Default	New and Existing Customers with Type 1-4 metering
	Small Business Basic	Default	Existing customers with basic meters
	IBT Business	Opt in for financially impacted customers only	New and Existing Customers
	Seasonal ToU Energy	Grandfather	Existing Customers
	Seasonal ToU Demand	Retired	Customers transferred to Small Business Demand
	Load Control Primary	Opt in	New and Existing Customers
Note: This schedule applies across our East, West and Mount Isa pricing zones.			

Secondary tariffs implementation strategy

Our current load control tariffs are secondary tariffs which can only be used in conjunction with a primary tariff in the SAC tariff class.

We are of the view that load control is an important tool in network management and provides benefits to all customers in the form of improved utilisation of network assets. As a result, and in alignment with customers' expectations, our strategy is to offer relevant load control services to customers that complement our existing and proposed demand tariffs. In addition, a primary load control tariff is proposed to be offered to small business customers.

Secondary tariffs volume controlled and volume night controlled will continue to be available to customers on legacy tariffs as well as optional cost-reflective tariffs.

A load control secondary tariff is also proposed for SAC Large customers.

5.3 Rationale for the new 2020-25 tariff structures

The term 'tariff structure' refers to the combination of the charging parameters within a specific tariff. The charging parameters that may be used when constructing network tariffs include a combination of the following:

- Daily supply charge (also known as fixed charge)
- Flat charge (also known as energy or volumetric charge)

- ToU usage charge
- Demand charge
- Capacity tariff demand charge
- Excess demand charge
- Capacity charge (SAC Small)
- Capacity charge (ICC and CAC).

Charging parameters are structured to provide signals to customers about the efficient use of the network and their impact on future network capacity and costs. Charging parameters are discussed in Section 4.3.

The section below details our approach in setting the charging parameters for the new cost-reflective tariffs.

5.3.1 SAC Small Customers

A suite of three new tariffs is proposed for both residential and small business customers – a Basic, Demand and Capacity Tariff. In addition, it is proposed that small business customers can access a primary load control tariff.

The structure of the Basic tariff is proposed as:

- Inclining volumetric blocks ($/kWh)
- Fixed charge ($/day).

In this tariff the inclining volume charge is used to reflect the additional capacity associated with higher energy consumption.

The Demand tariff structure is proposed as:

- Demand charge within a daytime (10am to 4pm) and evening window (4pm to 9pm) ($/kW/month)
- Fixed charge ($/day)
- Volume charge ($/kWh).

In this tariff the kW demand charge is used to recover LRMC.

The Capacity tariff structure is proposed as

- Fixed charge ($/day)
- Capacity tariff demand charge where daytime (10am to 4pm) capacity and evening (4pm to 9pm) capacity thresholds are exceeded ($/kW/month)
- Volume charge ($/kWh).

In this tariff kW capacity charges and the fixed charge are used to recover LRMC.

The small business primary load control tariff structure is proposed as:

- Fixed charge ($/day)
- Volume charge ($/kWh).

5.3.2 SAC Large Customers

Based on customer feedback there is significant interest from a number of sectors at the SAC Large level to access both primary and secondary load control network tariffs. Consultation feedback also indicated a preference amongst stakeholders that the SAC Large load control network tariff be offered as a broad-based tariff.

The SAC Large Primary Load Control Tariff structure is proposed as:

- Fixed charge ($/day)
- Volume charge ($/kWh).

The SAC Large Secondary Load Control Tariff structure is proposed as:

- Volume charge ($/kWh).

The fixed plus volume and volume only structures have been adopted as they align with the structure in SAC Small and therefore provide less complexity for both customers and retailers in terms of the implementation and adoption of these tariffs.

We also propose to adopt kVA demand-based charging parameters for SAC Large customers. This is expected to incentivise SAC Large customers to improve their power factor, which in turn will reduce network peak capacity requirements.

SAC Large customers would need to have metering infrastructure which supports half hourly kVA demand-based readings. Not all current SAC Large customers are expected to have this form of metering in place by 1 July 2020. Further, many customers are likely to face substantial costs associated with upgrading their metering arrangement to enable kVA based charging. Where there are issues associated with implementing kVA metering that prevent kVA billing data being available, a kW denominated version of the tariff is proposed to be offered.

In addition, a ToU energy tariff is proposed to be offered on a strictly limited access basis. This ToU energy tariff would only be available customers who have been on a retail transitional tariff in the period 1 July 2017 to 30 June 2020. This tariff comprises a fixed charge in $ per day, and peak and off-peak energy charges in $ per kWh, with the peak and off-peak periods aligned with those of the retail transitional tariffs T62 and T65.

5.3.3 Connection Asset Customers (CAC) and Individually Calculated Customers (ICC)

We do not propose to initiate any changes to the current structure of the CAC or ICC tariffs during the 2020-25 regulatory control period other than the removal of the excess kVAr charge.

5.3.4 Locational Charges

We are aware that the AER expects that future cost-reflective network tariffs will have a locational component as well as a peak time dimension. The basis of this is the LRMC of augmentation varies between different locations and that efficient tariffs would reflect this variation and make the locational cost transparent to customers.

The most value associated with locational signals is where the network is capacity constrained and customer responses to the high short-run costs associated with the particular location can enable substantial network investment value through deferral. These are the locations which are typically targeted by specific DM initiatives that will communicate the value of the location to customers and the market. Through this period, we will support the SCS tariffs with a suite of customer enabling mechanisms, which is consistent with our view that tariff reform is more than just introducing new tariffs.

Leading into the 2020-25 regulatory control period, implementation of locational tariffs in our network is viewed as introducing a level of complexity and new tariff dynamics across the supply chain that neither networks, retailers nor customers are seeking and which currently offer very little potential for benefit being realised. Locational LRMC is inherently unstable and can change very quickly. A major customer or development can change a location from unconstrained to constrained unpredictably which immediately impacts on the correct locational tariff. Between the TSS submission in January 2019 and its final year of application in 2025 the optimal locational tariff at a single location could swing widely as a result of actions of existing customers or plans of new customers.

While we accept value in providing transparency through to the market of cost of augmentation in constrained areas, the predictability that is implicit in the TSS construct does not translate to the dynamic realities of locational tariff setting.

We propose to achieve locational signals through overlaying locational DM initiatives that value and target specific locational value over the network tariff signals. This approach supports locational pricing that can adapt to evolving network circumstances and needs and can be accurately targeted, calibrated at the known opportunity value, and specifically harmonised in terms of the times, location, structure and tariff levels that optimises the network outcome. In the 2020-25 regulatory control period the SCS network tariff underlay dominates the signal through to the market.

5.4 Assignment of customers to tariff classes and tariffs

We consider the usage profile of customers in the assignment to tariff classes. In accordance with clause 6.18.4(a)(3) of the NER, we do not treat customers with micro-generation facilities less favourably than customers without such facilities but with a similar load profile in assigning customers to tariff classes. Our tariff class and tariff assignment procedures are detailed in Chapter 6 of the TSS.

5.5 Indicative pricing schedule for SCS

In accordance with the NER requirements, we have developed an indicative pricing schedule for SCS for each year of the 2020-25 regulatory control period. The indicative pricing schedule is included in Attachment A of the TSS.

It is important to note that these indicative charges are not the actual charges that a customer will pay each year but rather are intended to provide a robust guide to the likely charges. Actual tariffs may vary from the indicative tariffs in the TSS due to a variety of reasons such as under or over revenue collection in any individual year, future regulatory decisions for transmission revenue or successful cost pass through applications.

Actual charges experienced by our customers will depend on a number of factors outside of our control, including the consumption profile of each customer and the manner in which retailers pass through network charges to the customers in retail tariffs.

In addition, under the maximum revenue cap applied to our revenues earned from providing SCS, annual actual charges will differ from the indicative charges in the TSS to the extent that the electricity consumption and demand assumptions upon which the latter charges are based differ from the actual electricity consumed by customers.

For these reasons, we emphasise that the network tariffs presented are indicative only, not binding, and are for the purposes of providing a high-level overview of the expected distribution network bill impact for customers for the 2020-25 regulatory control period. Existing network tariff charges should not be extrapolated by the indicative annual charge increases without considering the impact of retailer strategies, customer adoption of alternative tariffs, changes to electricity usage or incentives provided to customers beyond our control in relation to how they consume electricity.

6 COMPLIANCE WITH PRICING PRINCIPLES

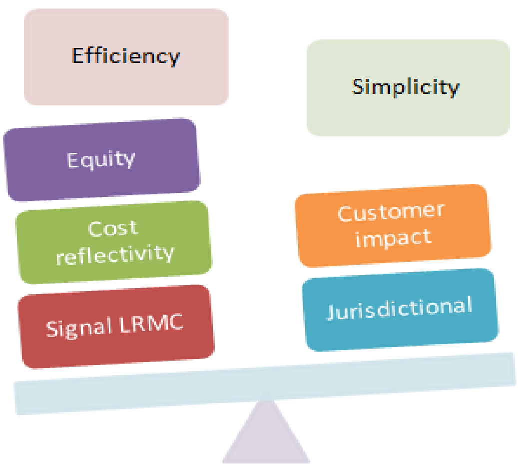
In complying with the pricing principles, we must meet the Network Pricing Objective, which is that the tariffs a distribution network service provider (DNSP) charges in respect of its provision of direct control services to a customer should reflect the DNSP's efficient costs of providing those services.

Clause 6.18.1A(b) of the NER requires that a TSS must comply with the pricing principles which are provided for in clause 6.18.5 of the NER. The pricing principles require that:

- The revenue to be recovered must lie between an upper bound (Stand-alone cost) and a lower bound (Avoidable cost)
- Tariffs must be based on the LRMC of providing the service
- Tariffs must be designed to recover our efficient costs of providing network services in a way that minimises distortions to the tariff signals
- We must consider the impact on customers of changes in tariffs from the previous year and may vary from the pricing principles after a reasonable period of transition to the extent necessary to mitigate the impact of changes
- The structure of each tariff must be reasonably capable of being understood by customers having regard to the customer types, feedback resulting from the engagement with customers and compliance with all the other pricing principles.

In some cases, the pricing principles may conflict or compete with each other. As noted by Deloitte, "each tariff design has its own strengths and weaknesses and it is unlikely that any particular tariff design will perform well against every factor or every circumstance".[2]

Figure 5 - Pricing principles



We consulted on the following principles during our engagement with customers on the TSS when designing and developing network tariffs:

[2] Deloitte Access Economics, Residential electricity tariff review – Report commissioned by the Energy Supply Association of Australia, Final Report, 22 January 2014.

- **Economic efficiency** – network tariffs signal the economic costs of providing distribution services to the market
- **Customer impacts** – we manage changes that are expected to affect customer bills for example progressive deployment of changes to avoid bill shock
- **Simplicity and transparency** – we offer customers a clear and simple tariff structure
- **Flexibility** – we provide innovative tariffs that support customer choice and control
- **Fairness** – similar customers pay similar tariffs and charges reflect the impact of customer usage and technology decisions on network costs
- **Stability** – bills should remain reasonably predictable and avoid bill shocks
- **Sustainability** – supports the energy tri-lemma strategy
- **Compliance** – network tariffs comply with all relevant regulations and the NER.

Respondents to our customer engagement were very clear in their priorities in regard to principles to be considered in developing the reform agenda that:

- Protects their constituent's position as a priority - including access, safety and network security, and
- Prioritises affordability, equity and transparency.

Respondents did have differing perspectives on what equity means to them.

The NER allows departure from the pricing principles to the minimum extent necessary to meet the consumer impact pricing principle or jurisdictional obligations.[3]

Compliance with the NER pricing principles is further discussed in the sections below.

6.1 Stand-alone and Avoidable cost

Our Distribution Cost of Supply (DCOS) model, used to calculate network tariffs, generates DUOS tariffs based on the full distribution of the building block costs (plus adjustments) that form the total allowed revenue approved by the AER.

The Avoidable and Stand-alone cost methodology described below is used to calculate the revenues for each SCS tariff class associated with each cost. These costs are compared with the weighted average revenue derived from our proposed tariffs.

6.1.1 Definition of Avoidable and Stand-alone costs

These two categories of cost may be defined for tariff classes, as follows:

- The **Avoidable cost** for a tariff class is the reduction in network cost that would take place if the tariff class were not supplied (whilst all other tariff classes remained supplied). If customers were to be charged below the Avoidable cost, it would be economically beneficial for the business to stop supplying the customers, as the associated costs would exceed the revenue obtained from the customer
- The **Stand-alone cost** for a tariff class is the cost of supplying only the tariff class concerned, with all other tariff classes not being supplied. If customers were to pay above the Stand-alone cost, then it would be economically beneficial for customers to switch to an alternative

[3] NER, clause 6.18.5(c).

provider. It would also be economically feasible for an alternative service provider to operate. This creates the possibility of inefficient bypass of the existing infrastructure.

There are two alternative concepts that could be used to calculate these costs:

1. To ignore the sunk nature of the existing network and estimate the costs which would be associated with an optimally designed network, constructed to supply SCS to the tariff class or classes concerned, or

2. To base the estimation of costs on the modification of the existing network to provide SCS to the tariff class or classes concerned.

The NER does not prescribe the methodology that should be used to calculate the Stand-alone and Avoidable costs of tariff classes of the network. We have chosen to base our cost estimations on the second concept, based on the hypothetical modification of the existing network, rather than by devising and costing optimal new network structures. This has been done for two reasons:

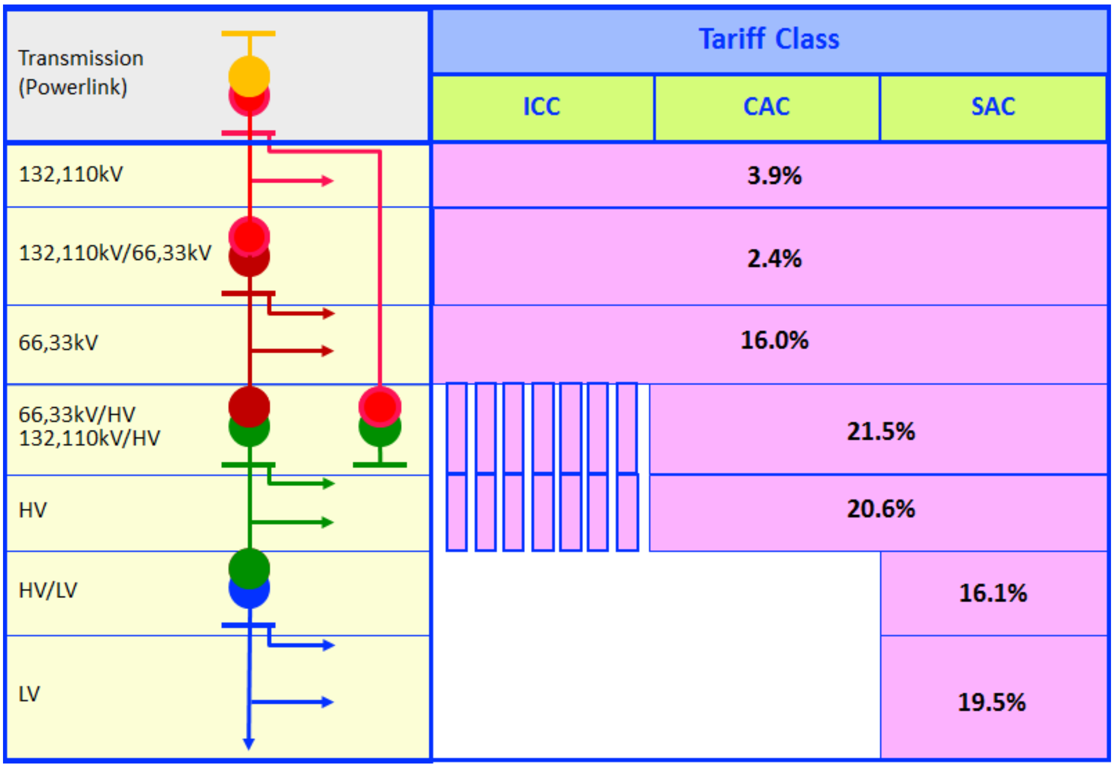
- To avoid the very substantial resource requirements that would be involved in a full network redesign

- In recognition that the economic regulatory framework for distribution supports the existence and value of existing (sunk) network investments and does not support the optimisation of existing networks.

The approach that we have adopted is consistent with the approach adopted by Energex. In our case the approach is the same as that which was employed during the 2015-20 regulatory control period, and subsequently approved by the AER.

The DCOS model is also used to estimate the Stand-alone and Avoidable costs for each tariff class, in the manner described below.

Figure 6 – Cost allocation for Stand-Alone and Avoidable network costs



To the right of the figure above, there is a schematic illustration of the connectivity of the network between the successive system levels, from transmission through sub-transmission to HV and thence to LV.

Replacement asset costs have been used in this model as the basis for the cost allocation to tariff classes and to determine the avoidable and Stand-alone cost proportions. The proportions of asset costs associated with each level of the network are also shown.

We have changed the tariff classes used in the 2017-20 TSS period to create a simplified grouping of three tariff classes that align with those of Energex. The system connection voltage level of the constituent tariffs that make up the three tariff classes is shown in the table below:

Table 7 – System connection level of tariffs forming the tariff classes

System Connection	ICC	CAC	SAC
132, 110kV	X	X	
66,33 kV	X	X	
22, 11kV Bus	X	X	
22, 11kV Line		X	X
LV Bus			X
LV line			X

6.1.2 Lower bound test (Avoidable cost)

We estimated the avoidable costs by responding to the following questions:

> *"If the ICC/CAC/SAC tariff class was not connected to the network, what assets would not be required? If these assets are not required, what revenue should not be collected?"*

The network was assumed to remain in its current state with supply voltages unchanged. Individual classes of assets and their associated costs were 'optimised' by removing a proportion of those costs to reflect the fact the demand is notionally reduced for each tariff class not supplied, whilst still maintaining the same standard of network service for the remaining tariff groups.

Figure 7 – Avoidable network cost calculation

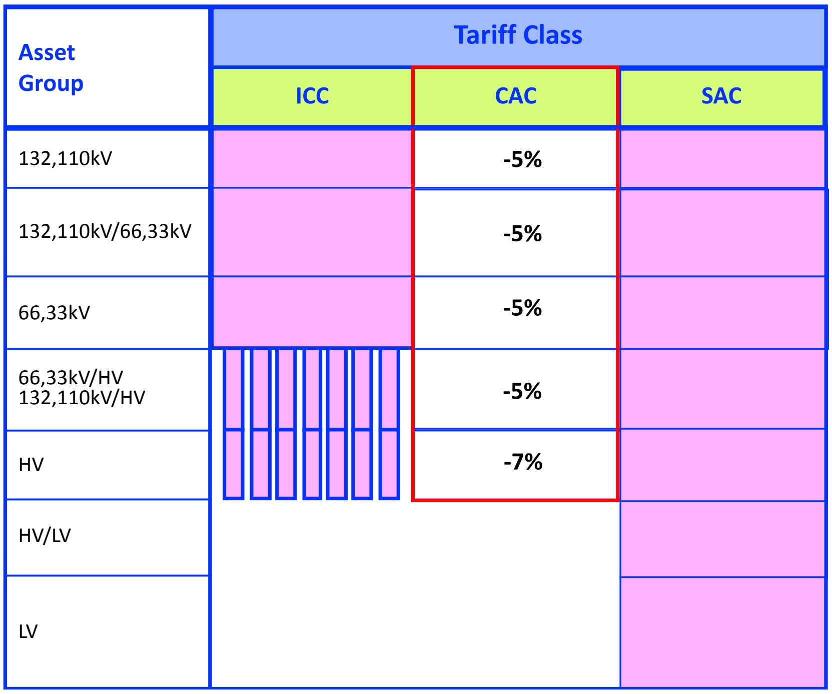


Figure 7 above illustrates the hypothetical proportions of network assets that would be avoided if the CAC tariff class were to be removed. This is repeated for each of the other tariff classes in turn. The associated percentages express the Avoidable cost as a proportion of the total revenue recovered through the tariff class. For each tariff class, the Avoidable cost is less than the tariff class revenue and the tariff classes are therefore compliant with the NER.

6.1.3 Upper bound test (Stand-alone cost)

Our estimate of the stand-alone cost was determined from a similar assessment of the network capability, in response to the following questions:

> *"If only one tariff class were to be supplied, what assets would be required to supply only this tariff class? If only these assets are required, what revenue would need to be collected?"*

As before, the network is assumed to remain in its current state with supply voltages unchanged. Individual classes of assets and their associated costs are 'optimised' by removing a capacity-based proportion, whilst still notionally retaining the necessary capacity and reliable supply to just the tariff class concerned.

Figure 8 – Stand-alone network cost calculation

Asset Group	Tariff Class		
	ICC	CAC	SAC
132,110kV		95%	
132,110kV/66,33kV		95%	
66,33kV		95%	
66,33kV/HV 132,110kV/HV		80%	
HV		80%	
HV/LV			
LV			

In Figure 8 above, the columns contain the hypothetical proportions of network assets that would be required if only one of the three tariff classes were to be supplied, in turn. The associated totals in each row express the stand-alone cost as a proportion of the revenue recovered from the tariff. For each tariff class, the stand-alone cost is greater than the tariff class revenue and the tariff class is therefore compliant with the NER.

6.2 Long run marginal cost

We have estimated the LRMC values at each major voltage level of its network for use as the basis of network tariffs, as required by clause 6.18.5(f) of the NER.

In essence the calculated LRMC provides a cost reflectivity target. Tariffs would trend towards the target subject to other pricing considerations. As such, it targets lower network and customer costs and has economic efficiency as its overriding objective. The use of the network LRMC for pricing is required by the NER.

The following is a description of how our LRMC has been estimated using a Long Run Incremental Cost (LRIC) model, similar to that developed by the Energy Networks Association (UK) and approved by Ofgem, their industry regulator[4][5]

6.2.1 Alternative LRMC calculation approaches

There are three generally accepted methods of estimating the LRMC for network businesses. These are:

- The Average Incremental Cost (AIC) approach, in which the growth-related components of current expenditure and demand forecasts provide the cost estimate
- The Perturbation or "Turvey" approach, in which the altered capital and operating costs associated with a hypothetical permanent change in demand provide the basis for the cost estimate
- The LRIC approach which calculates the annualised cost of the next proposed investment to meet an increment in demand. The most relevant example of this approach is the Common Distribution Charging Methodology (CDCM), which has formed the basis for distribution tariffs in the United Kingdom for many years. This methodology more commonly known as the 500MW model.

To date, we (and other DNSPs in the National Electricity Market) have used an AIC model. However, there are a number of issues that make the continuation of this approach problematic. In summary, these are:

- The model is based on a five to ten-year regulatory forecast of demand growth and the related associated incremental capital and operating costs prepared for the AER determination. These truncated forecasts are subject to cyclical variation associated with the longer actual investment cycle and variation in factors such as planning risk which, if not moderated, leads to unstable estimation of the LRMC. This can be due to the "lumpiness" and infrequent nature of major capital expenditure, prevailing economic conditions and fluctuations in customer connections and development
- The 2020-25 regulatory control period is a time of overall low demand growth and low capital expenditure and therefore the LRMC in $/kW has a small numerator and small denominator. The calculation becomes numerically unstable in these circumstances and can inaccurately estimate the LRMC
- The net demand growth comprises new and modified connections, offset to an extent by disconnections and the reduction in demand at some existing premises. A proportion of replacement capital expenditure also provides additional useable capacity. Applying engineering judgement introduces a level of subjectivity that can be pivotal to the LRMC outcome, but at times of low demand growth and expenditure these adjustments can constitute a significant component of the resultant LRMC.

---

[4] Energy Networks Association (UK), *CDCM model user manual Model Version: CDCM model user manual Model Version: 103,* 28 August 2015.
[5] Ofgem, *Electricity distribution structure of charges: the common distribution charging methodology at lower voltages, Decision Document Ref: 140/09*, 20 November 2009.

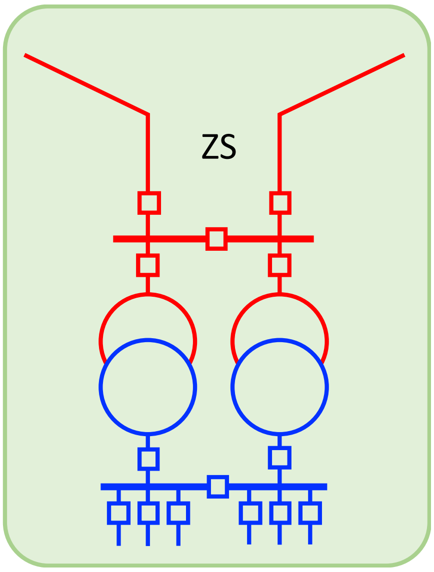
The Perturbation approach has the disadvantage that it effectively requires re-estimation of the capital and operating expenditure programs for a large number of assumed demand growth scenarios. This calculation is thus resource-intensive.

The following section describes the implementation of the third approach, LRIC, to our network. This is a modelling approach which is similar to that used in the UK sometimes termed the “500MW model”.

6.2.2 The LRIC model

This model is based upon the creation of a hypothetical optimised network scaled to supply a total coincident demand of 500MW, using “building blocks” comprised of modern equivalent assets. These elements embody the current planning standards, spatial characteristics, standardised equipment, average route lengths, and utilisation levels typical for our network. The model effectively replicates a scaled version of the existing network fully representative of its underlying characteristics.

For example, at the 132 or 110kV zone substation level, a generic zone substation based on recently constructed projects is used. This is depicted below.



A zone substation building block comprises the following elements:

- Upstream 132/110kV feeders of average number and length, and with the average underground to overhead proportions applicable to our network
- Typical layout including busbars, transformers of the usual modern rating and a typical number of outgoing feeder circuit breakers.

Similar building blocks are created for each of the following system elements, in each case including their upstream feeders:

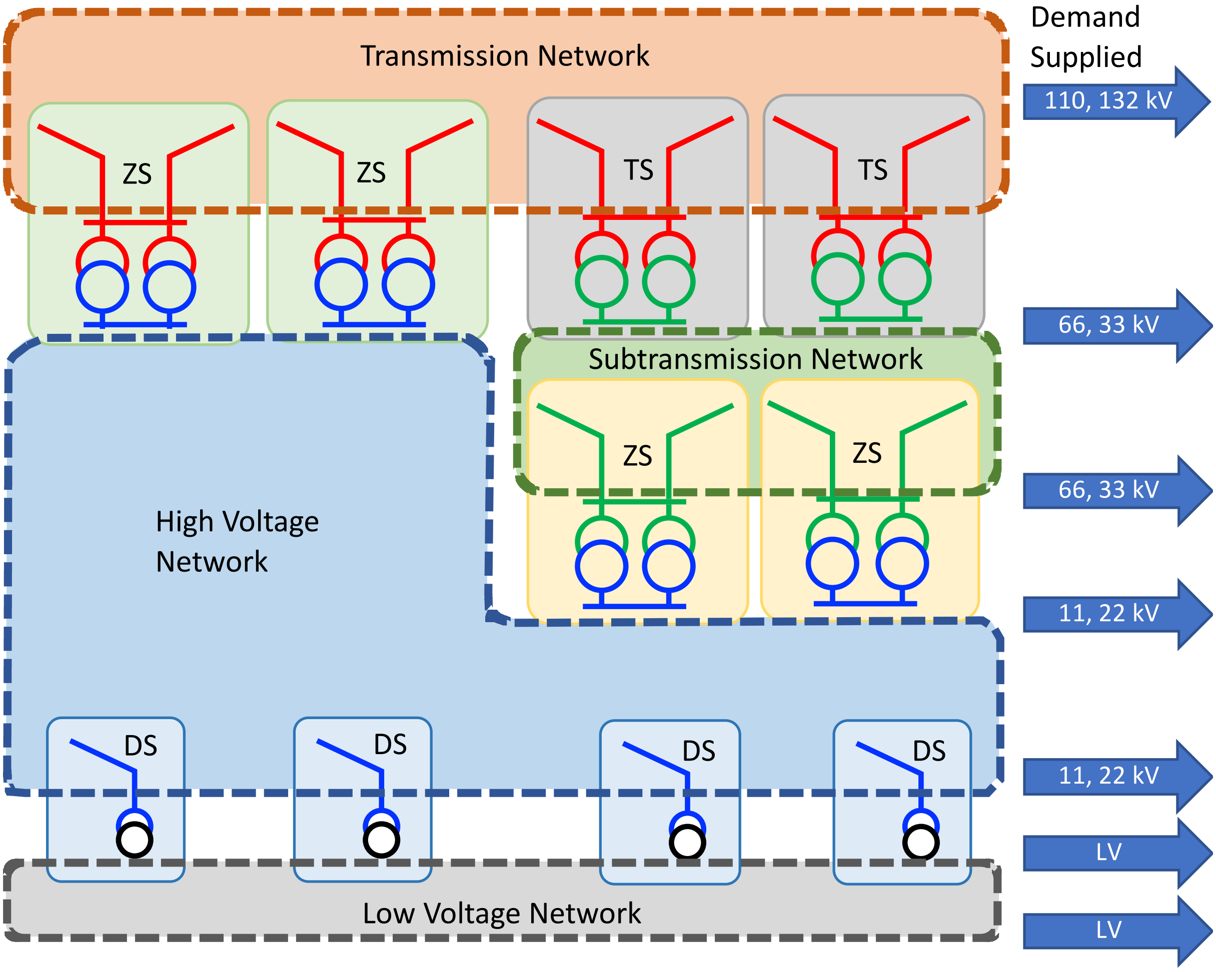
- 132 or 110kV/66 or 33kV sub-transmission substation (rural and urban)
- 66 or 33kV/HV zone substation (rural and urban)
- 132 and 110kV/HV zone substations (rural and urban)
- HV network (rural, urban and remote rural)
- HV/LV substation (kiosk and pole top).

The LV network is also included in the model, on a similar basis (same length/capacity and overhead/underground ratios) as for the existing network. Each building block is assigned a capacity that can include emergency ratings and load transfers, reflecting our normal practice in managing contingencies. The replacement cost of each building block has been estimated from the cost of recent and current capital works.

6.2.3 Structure of LRIC model

The building blocks are then assembled into a hypothetical network capable of supplying a total demand of 500MW, apportioned between system voltage levels in the same ratio as for our network. The figure below depicts the assemblage of building blocks. The number of building blocks of each type is determined by their net capacity and the demand that is supplied through the downstream levels of the network. Whilst the UK model uses integral numbers of building blocks, we use fractions of blocks to avoid step variations in cost arising from the demand assumptions. This also enables costs to be calculated for areas such as our West and Mount Isa pricing zones, which have relatively small demand.

Figure 9 - LRIC Building Blocks



This LRIC model is, in effect, an optimal representation of the network using modern equipment and construction techniques. The model preserves the average spatial characteristics and technical requirements (eg. optimal equipment capacities) of our network.

The demand connected at each voltage level matches our network profile, using the coincident peak demand for the system, and is scaled to 500MW. There is no spare capacity within this optimal network, which is created to just match the demand.

The maximum coincident demand of 500MW for the model was chosen in the UK to represent a material demand increase and, by being uniform, to facilitate comparisons between their 14 DNSPs. This demand of 500MW has been retained for our models.

6.2.4 Cost estimates

The optimised replacement cost of the assets that form the building blocks provides the basis for their cost estimate, using the real weighted average cost of capital and standard asset lives determined by the AER. To this is added a standardised allowance for operation and maintenance, expressed as a percentage of the asset replacement costs.

Consistent cost estimates have been developed for line and substation costs. These estimates reasonably represent the cost that would be incurred in greenfield construction of the associated asset. They include the capitalised overheads that would be included in an asset that was incorporated in the Regulated Asset Base (RAB). Land and easement values are not included in developing these cost estimates. Line and cable costs in particular were chosen to represent the cost of reasonable-sized projects, rather than a scaling-up of short-length projects with relatively high unit costs.

6.2.5 Voltage level LRMC estimates

The resultant hypothetical network costs were allocated to the system voltage levels and the throughput of each system level in kW was then used to determine an average $/kW for each voltage level. For example, sub-transmission substation costs were allocated downstream to sub-transmission, HV and LV levels.

These $/kW costs were applied to the Coincident Demand supplied by us to determine the LRMC expressed in $/kW/annum at each voltage level. Finally, the average power factor at each voltage level was used to determine the LRMC values, expressed in $/kVA/annum, that apply to the coincident demand at that voltage level.

6.2.6 Tariff level estimates

The LRIC model does not convert the LRMC rates into tariff quantities such as demand and peak energy rates. Rather, voltage level LRMC rates are taken into DCOS, where the tariff level conversions are performed.

The form of conversion to tariff rates within DCOS depends upon the peak period charge through which the LRMC is recovered. In broad terms, the impact of the tariff on the network's cost through its contribution to the coincident peak demand is calculated in dollar per annum terms. That dollar amount is recovered through the tariff rate (eg. $/kVA or kW, $/MW) subject to considerations of the individual customer impact.

6.2.7 Model Outcomes and Comparison with 2017-20 rates

LRMC values per annum at each major voltage level of its network (sub-transmission, HV and LV) are set out in the table below:

Table 8 – Comparison of Proposed 2020-21 and current 2018-19 LRMC values by voltage levels (Nominal)

Ergon Energy East and Mount Isa

Voltage Level	LRMC 2020-21 $/kVA/annum	LRMC 2018-19 $/kVA/annum
132/110/66kV/33kV	$72	$33
22/11kV	$141	$175
LV East	$226	$255
LV Mount Isa	$103	

Notes:
- The figures are undiversified
- The figures are exclusive of GST.

Ergon Energy West

Voltage Level	LRMC 2020-21 $/kVA/annum	LRMC 2018-19 $/kVA/annum
132/110/66kV/33kV	$107	$93
22/11kV	$360	$437

Voltage Level	LRMC 2020-21 $/kVA/annum	LRMC 2018-19 $/kVA/annum
LV	$660	$638
Notes: • The figures are undiversified • The figures are exclusive of GST.		

It is proposed that the LRMC values will be adjusted by CPI throughout the regulatory control period.

6.3 Managing customer impacts

Clause 6.18.5(h) of the NER requires that we must consider the impact on customers of changes in tariffs and may vary tariffs to the extent it considers reasonably necessary, having regard to:

- The desirability for tariffs to comply with the pricing principles after a reasonable period of transition
- The extent to which customers can choose the tariff to which they are assigned
- The extent to which customers are able to mitigate the impact of changes in tariffs.

We understand that a move to new tariff structures and cost-reflective tariffs will impact customers differently.

This section provides a customer impact assessment of our proposed network tariff reforms using the most up to date indicative charges. It details how customers who do choose to adopt demand tariffs can respond through usage behavioural change and technology adoption.

We consider customer impact based on comparisons to our default “legacy” tariffs. These default legacy tariffs are those network tariffs contained in the 2017-20 TSS and set as default for their respective tariff classes. For our residential customers, this tariff is Residential IBT and for our Small Business Customers, Business IBT.

It is important to note that our distribution network charge reductions, as set out in section 6.3 of our TSS Explanatory Notes for residential and small business customers, will also be experienced by those regional Queensland customers on notified retail prices, as a result of the Queensland Government’s uniform tariff policy. The remainder of this section only considers the reduction to our distribution network charges.

6.3.1 Modelling Customer Impact

We have elected to undertake modelling of customer impact based on actual data taken from a sample of customers. This sample explores the annual maximum usage of customers within each customer class. It takes the data “as is” in that it does not consider changes to customer behaviour due to tariff changes year on year.

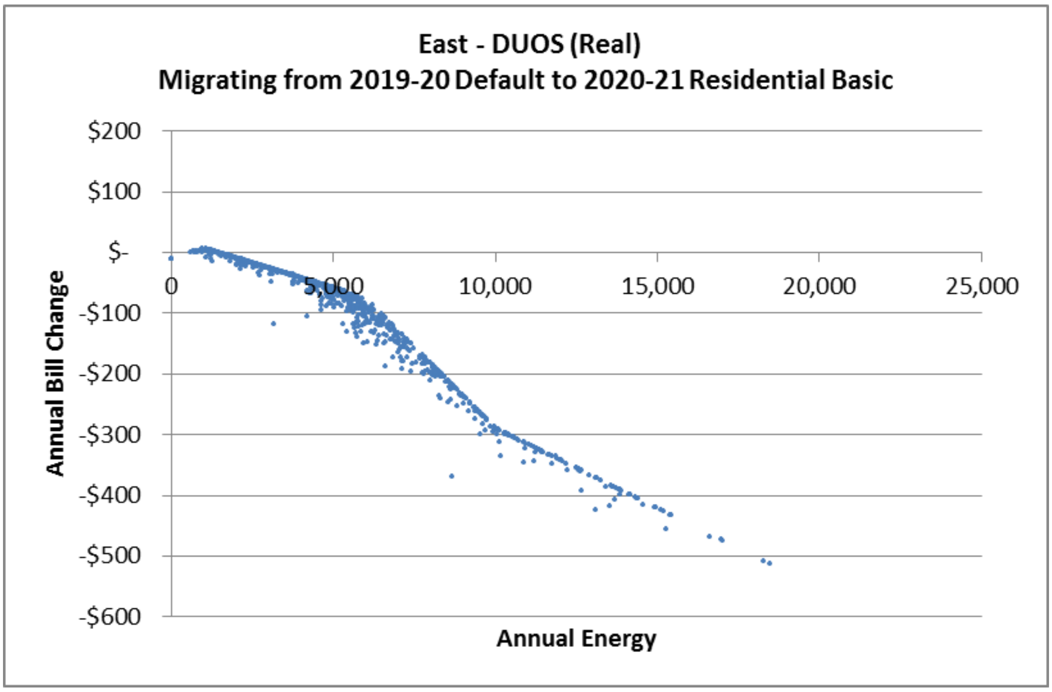
For ease of use, two customer sample sets have been developed. The first is a sample of customers to represent a class of customers to provide indicative population impacts. For example, in our Residential Customer Class, approximately 1,350 of a pool of 495,000 customers were selected. Each customer included in this sample has scaling factor applied indicating how many “like” customers they portray. This enables us to scale outcomes in our modelling. However, to streamline presentation, we have omitted this scaling factor from our charts. The second is sub-selection of three representative customers (small, average, large) to provide easily to relate to impacts for customers. The sample sets were drawn from customers with interval data.

We recognise that customers and stakeholders are seeking more granular customer impact analysis to inform their assessment of our proposed network tariffs, and that this feedback has been clearly stated in responses provided to the AER's Issues Paper consultation in May 2019. We are responding to this feedback at the time of preparing this TSS in June 2019 by embarking on a joint exercise with the AER and a leading industry service provider to greatly expand the level of customer impact analysis in line with the direct feedback provided by customers and stakeholders to date. Outcomes of this analysis will be presented to customers and stakeholders prior to the AER's Draft Decision and will also be included in our Revised TSS submission.

6.3.2 Impact of tariff reform on residential customers

6.3.2.1 Residential Customers shifted to Residential Basic Tariff

We are committed to achieving a real reduction[6] in distribution network charges for residential customers on the default network tariffs from 2019-20 to 2020-21 of approximately 4.5% on our Residential Basic Tariff. These rate reductions are reflected throughout the customer population as demonstrated in the following chart:



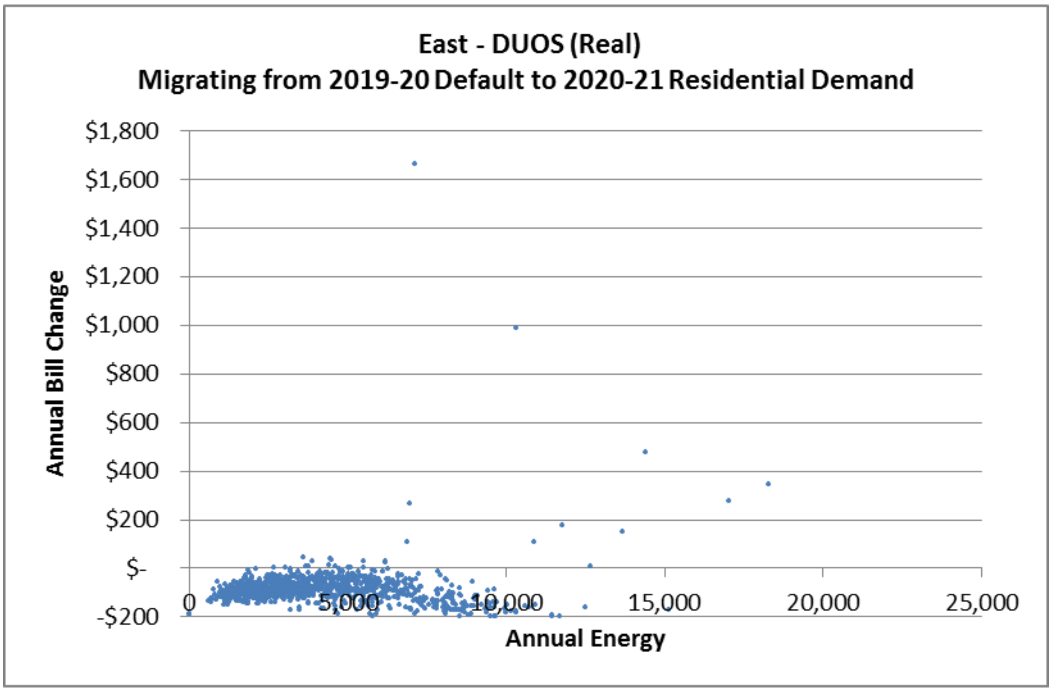
Note: one data point on this chart may represent one or many customers as noted in 6.3.1.

6.3.2.1 Residential Customers Migrating to Residential Demand Tariff

Existing residential customers who opt-in to the Residential Demand tariff in 2020-21 will also have the opportunity to realise reductions in the distribution network component of their bill. These rate

[6] This does not account for jurisdictional schemes which may factor into total network charges, where total network charges comprise distribution network charges, transmission network charges and jurisdictional schemes

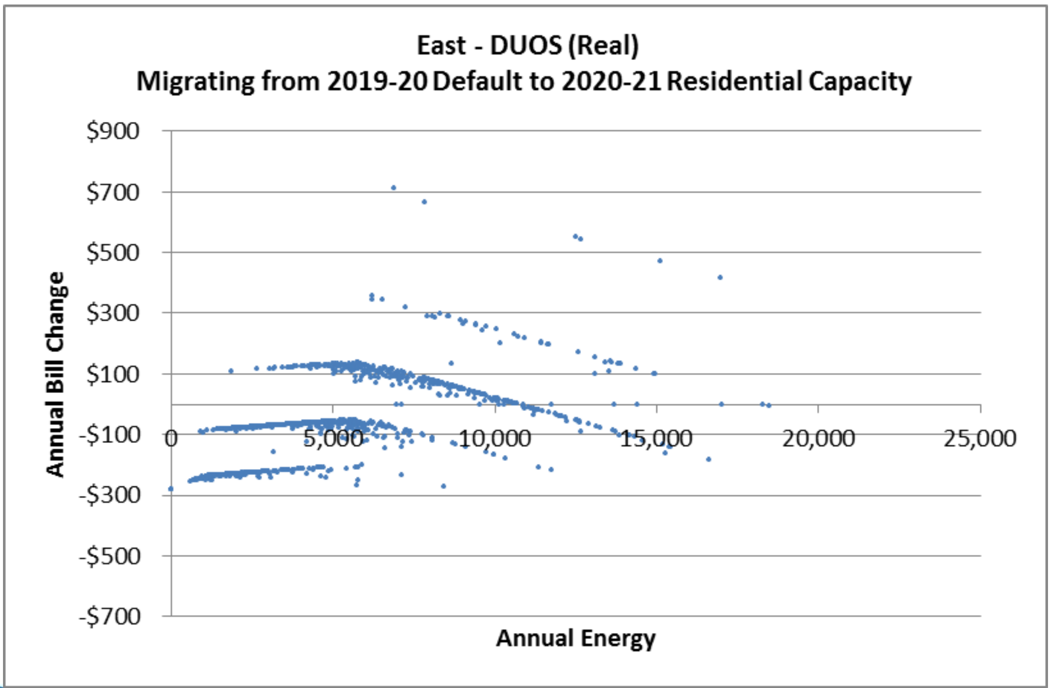
reductions are reflected throughout the customer population as demonstrated in the following chart based on their individual usage needs:



Note: one data point on this chart may represent one or many customers as noted in 6.3.1.

6.3.2.1 Residential Customers Migrating to Residential Capacity Tariff

Existing residential customers who opt-in to the Residential Capacity tariff in 2020-21 will also have the opportunity to realise reductions in the distribution network component of their bill, pending their individual usage needs. We offer this tariff under an opt-in arrangement to ensure the tariff is the best fit for those customers choosing to select the tariff. The indicative reductions in the distribution network component of those customers' bills are set out in the table below based on their individual usage needs:

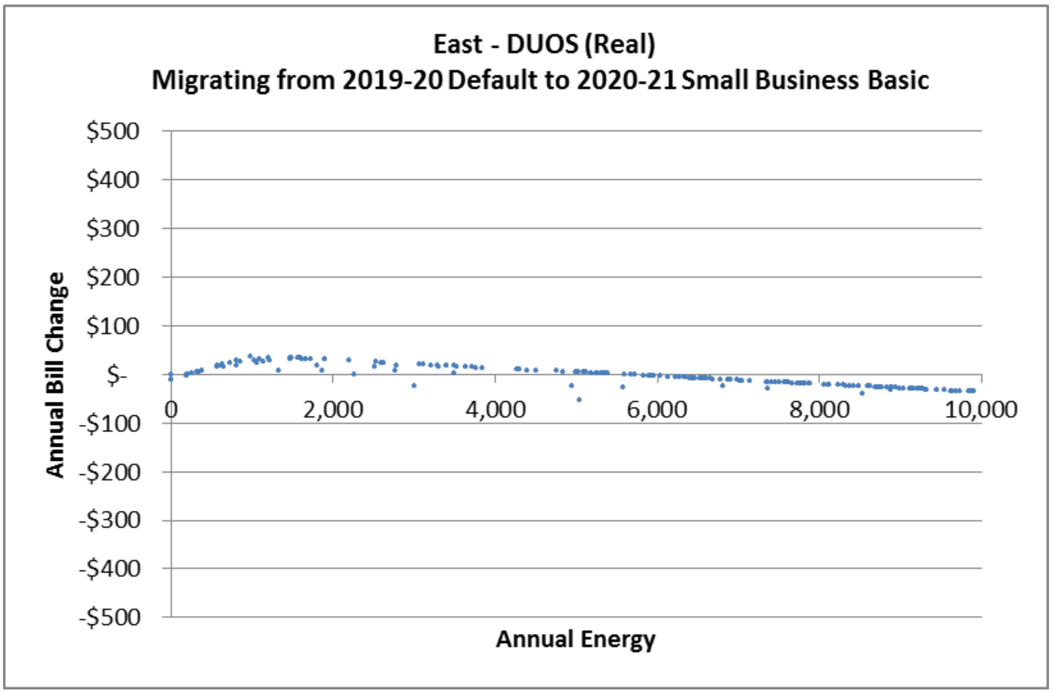


6.3.3 Impact of tariff reform on small business customers

6.3.3.1 Small Business Customers shifted to Small Business Basic Tariff

We are committed to achieving a real reduction[7] in distribution network charges for small business customers on the default network tariffs from 2019-20 to 2020-21.

These rate reductions are reflected throughout the customer population as demonstrated in the following chart:

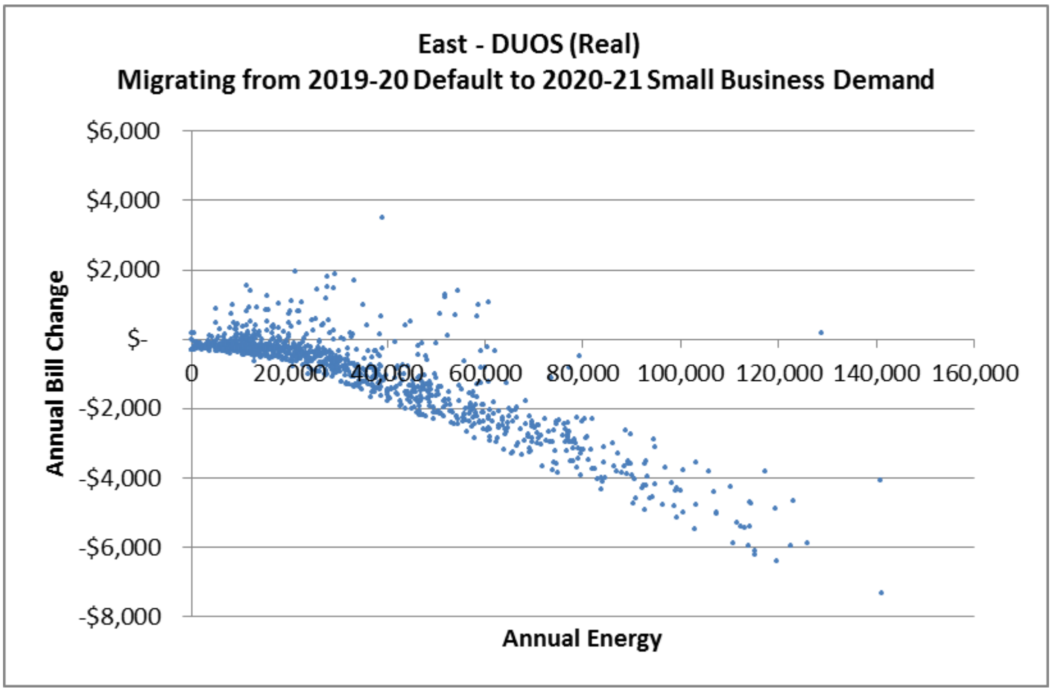


Note: one data point on this chart may represent one or many customers as noted in 6.3.1.

6.3.3.2 Small Business Customers Migrating to Small Business Demand Tariff

Existing small business customers who opt-in to the Small Business Demand tariff in 2020-21 will also have the opportunity to realise reductions in the distribution network component of their bill. These rate reductions are reflected throughout the customer population as demonstrated in the following chart based on their individual usage needs:

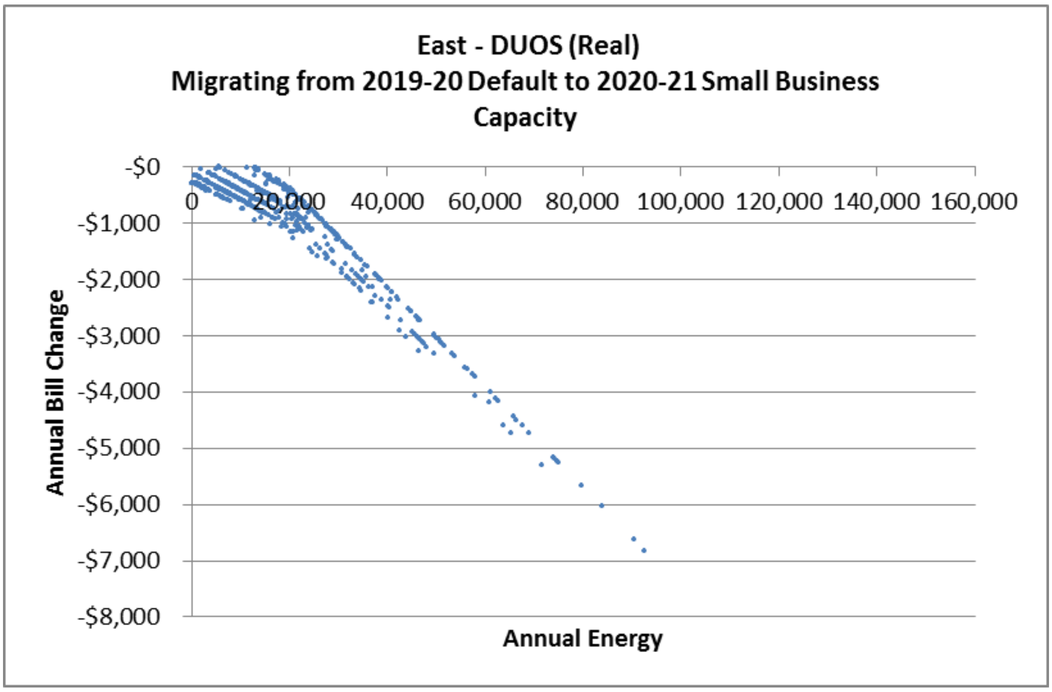
[7] This does not account for jurisdictional schemes which may factor into total network charges, where total network charges comprise distribution network charges, transmission network charges and jurisdictional schemes.



Note: one data point on this chart may represent one or many customers as noted in 6.3.1.

6.3.3.1 Small Business Customers Migrating to Small Business Capacity Tariff

Existing small business customers who opt-in to the Small Business Capacity tariff in 2020-21 will also have the opportunity to realise reductions in the distribution network component of their bill, pending their individual usage needs. We offer this tariff under an opt-in arrangement to ensure the tariff is the best fit for those customers choosing to select the tariff. The indicative reductions in the distribution network component of those customers' bills are set out in the table below based on their individual usage needs:



6.4 Stakeholder Engagement

Please refer to *Tariff Structure Statement 2020-25 Engagement Summary* for a summary of the outcomes from our detailed customer and stakeholder engagement undertaken as we developed our TSS documents. A summary of a selection of responses of a technical nature are included in Appendix A of these Explanatory Notes.

A summary of a selection of responses of a technical nature are included in Appendix B of these Explanatory Notes.

7 ALTERNATIVE CONTROL SERVICES

Services provided under the ACS framework are customer specific and/or customer-requested services. These services may also have potential for provision on a competitive basis rather than by a single DNSP. ACS are akin to a 'user-pays' system. The whole cost of the service is paid by those customers who benefit from the service, rather than recovered from all customers.

Consistent with the F&A, all ACS are subject to a price cap control mechanism. Our ACS include:

- Connection services (ie. excluding those services classified as SCS in the F&A)
- Ancillary Network Services
- Type 6 Metering Services (the F&A refers to these as Type 5 and 6 Metering Services, but Type 5 meters are not permitted in Queensland and for clarity we refer to these only as Type 6 Metering Services)
- Public Lighting Services.

Type 6 metering services, public lighting services and fee-based ancillary and connection services have been calculated in accordance with the formula set out in Figure 2.2 of the F&A, and our quoted services (services of a nature and scope which cannot be known in advance) will be calculated in accordance with the formula set out in Figure 2.3 of the F&A.

7.1 ACS Classification of Services

For the 2015–20 regulatory control period, the AER has classified the following as ACS and these have formed the basis of tariff classes for ACS which are described in the table below:

Table 9 - ACS tariff classes

Tariff Class	Activity
Connection services	**Pre-connection services** Pre-connection services are those services that relate to assessing a connection application, making a connection offer and negotiating offer acceptance and additional support services provided by the DNSP (on request) during connection enquiry and connection application other than general connection enquiry services and connection application services. Generally relates to services which require a customised or site-specific response and/or are available contestably. Unless otherwise specified, services or activities undertaken under this service group relate to both small and large customers and real estate development connections.
	Connection services Connection services include the design, construction, commissioning and energisation of connection assets for large customers and for real estate developments. Also includes the augmentation of the network to remove a constraint faced by an EG. This does not include customers with micro-generation facilities that connect under a SAC tariff class. We consider that generators larger than 30kVA but smaller than 1MW should be treated as EGs for the purpose of removing network constraints. Include temporary connections for short term supply (eg. blood bank vans, school fetes).
	Post-connection services Post-connection services are those services initiated by a customer which are specific to an existing connection point.
	Accreditation services Accreditation of alternative service providers and approval of their designs, works and

Tariff Class	Activity
	materials.
Ancillary network services	Ancillary network services include services which are not covered by another service and are not required for the efficient management of the network, or to satisfy DNSP purposes or obligations.
Metering services	**Type 6 Metering** Metering services encompass the metering installation, provision, maintenance, reading and data services of Type 6 metering. **Auxiliary Metering Services** Includes work initiated by a customer which is specific to a metering point.
Public lighting	Public lighting services relate to the provision, construction and maintenance of public lighting assets owned by us (conveyance of electricity to public lights remains an SCS). Includes energy efficient retrofits and new public lighting technologies, including trials.

7.2 Connection services

The lists of services which fall under the connection services classification are listed in the table below. Consistent with the approach adopted for other ACS, services have been determined to be fee-based or quoted depending on whether the scope of work is pre-defined or subject to variability.

Table 10 - Charges for connection price capped services

Category	Service Description	Charging arrangements
Pre – connection services (connection application services)		
Protection and power quality assessment prior to connection - simple	Investigation into Power Quality issues including Flicker, Harmonics and DC voltage injection.	Quoted
Application services	Application fee for a Negotiated connection offer. Services associated with assessing an application requesting a connection to be made (or altered) between the distribution network and the customer's installation, and the costs associated with negotiating and preparing a negotiated connection offer.	Quoted
Pre - connection services (consultation services)		
Site inspection in order to determine nature of connection	Site inspection in order to determine nature of connection being sought.	Quoted
Provision of connection advice	Provision of connection advice, assessment and data requests for site-specific connections (during the connection enquiry and/or connection application stage). For example: • Embedded generation assessments • Advice on project feasibility • Concept scoping • Project estimation • Advice on whether augmentation would likely be required • Capacity information, including specific network capacity • Load profiles for load flow studies • Requests to review reports and designs prepared by external consultants, prior to lodgement of connection application • Additional or more detailed specification and design options.	Quoted
Preparation of preliminary	Preparation of preliminary planning and design reports for major	Quoted

Category	Service Description	Charging arrangements
designs and planning reports	customer connections, including project scopes and estimates. Initial specification and design outline for major customer connections. Includes general evaluation and advice on asset ownership options, indicative estimates of viable connection options, and recommendation on the most suitable option.	
	Provision of advice, design and specification on request to an applicant considering a build-own-operate asset ownership option for connection assets.	Quoted
	Detailed enquiry response fee Costs associated with preparing a detailed enquiry response pursuant to Chapter 5 of the NER. Applies to any embedded generation connection applicant that submits an enquiry under the connection process set out in Chapter 5 of the NER and seeks a detailed enquiry response.	Quoted
Tender process	Applies where the DNSP conducts a tender process on behalf of a connection applicant to procure connection services that can be provided by a third party, or where the connection applicant conducts a tender process and requires assistance from the DNSP.	Quoted
Connection services		
	Customer-requested temporary connection (short term) and the recovery of the temporary builder's supply. Excludes work on metering equipment.	Fee-based
Post Connection Services		
Supply Abolishment (simple)	Retailer requests us to abolish supply at a connection point and decommission a NMI. May be used where a property is to be demolished; supply is no longer required; an alternative connection point is to be used; or a redundant supply is to be removed. Overhead/Underground.	Fee-based
Supply Enhancement	Service upgrade. For example, an upgrade from single-phase to multi-phase and/or increase capacity. Applies to underground and overhead service upgrades. Excludes work on metering equipment (if required). Overhead/Underground.	Fee-based
Point of attachment relocation	Customer requests their existing overhead service to be replaced or relocated, eg. as a result of point of attachment relocation. No material change to load. This includes de-energisation, followed by physical dismantling then reattachment of service and re-energisation. Excludes work on metering equipment (if required).	Fee-based
Re-arrange connection assets at customer's request	Rearrange connection assets at customer's request - simple (upgrade from overhead to underground where main connection point is in existence). Recovery of the overhead service and connection of the consumer mains to the pre-existing pillar for a customer-requested conversion of existing overhead service to underground service.	Fee-based
Temporary disconnections and reconnections (which may involve a line drop) - LV	Temporary de-energisation and re-energisation of supply to allow customer or contractor to work close - the service may be physically dismantled or disconnected (eg. overhead service dropped). This service includes switching if required. Temporary LV service Drop and re-erect (dismantling).	Fee-based
Faults/Emergency response	Attending loss of Supply - customer fault.	Fee-based

Category	Service Description	Charging arrangements
Attendance at customer premises to perform a statutory right where access is prevented	Crews attend site at the customer's request and is unable to perform job due to customer's fault/fault of a third party.	Fee-based
De-energisations	Retailer requests de-energisation of the customer's premises where the de-energisation can be performed at the premises by a method other than main switch seal (ie. at pillar box, pit or pole top).	Fee-based
	Retailer Requested de-energisation (Main Switch Seal – MSS).	Fee-based
Re-energisations	Retailer requests re-energisation of the customer's premises where the customer has not paid their electricity account. No visual required.	Fee-based
	Retailer requests re-energisation for the customer's premises following a main switch seal (no visual required).	Fee-based
	Retailer or metering coordinator/provider requests a visual examination upon re-energisation (physical) of the customer's premises.	Fee-based
	Retailer requests a visual examination upon re-energisation (physical) of the customer's premises where the customer has not paid their electricity account. NMI de-energised > 30 days.	Fee-based

7.3 Ancillary network services

Our classification of ancillary network services is provided in the table below. Consistent with the approach adopted for other ACS, services have been determined to be fee-based or quoted depending on whether the scope of work is pre-defined or subject to variability.

Table 11 - Classification of ancillary network services

Service Group	Charging arrangements
Services provided in relation to the retailer of last resort	Quoted
Other recoverable works:	
Travel time to perform the installation of a service requested by a retailer or customer, and the service is unable to be performed due to customer/retailer fault. One crew.	Fee-based
Travel time to perform the installation of a service requested by a retailer or customer, and the service is unable to be performed due to customer/retailer fault. Two crews.	Fee-based
Customer requests provision of electricity network data requiring customised investigation, analysis or technical input (eg. requests for pole assess information and zone substation data).	Quoted
Provision of unmetered equipment services to extend /augment the network, to make supply available for the connection of approved unmetered equipment, eg. watchman light, public telephones, , extension to the network to provide a point of supply for a billboard & city cycle. Temporary connection of unmetered equipment to an existing LV supply. Request to de-energise or abolish an unmetered supply point.	Quoted
Works initiated by a customer, retailer or third party which are not covered by another service and are not required for the efficient management of the network, or to satisfy distributor purposes or obligations. Includes, but is not limited to:	Quoted

Service Group		Charging arrangements
	• restoration of supply due to customer action • re-test at customer's installation (ie. customer has submitted Form A and the Retailer has issued a Service Order Request, but installation fails test and cannot be connected, requiring a re-test of the installation) • safety observer • tree trimming • switching • cable bundling • checking pump size for tariff eligibility.	
	Removal, relocation or rearrangement of network assets (other than connection assets) at customer's request, that would not otherwise have been required for the efficient management of the network.	Quoted
	Installation of aerial markers (or Powerlink Hazard Identifiers) on overhead lines.	Quoted
	Customer-requested disconnection and reconnection of supply, coverage of LV mains and/or switching to allow customers/contractors to work close, eg. Tiger Tails	Quoted
	Overhead service connection – non-standard installation. Flying Fox (catenary) Overhead Connection: difference between the cost of a standard OH service and the cost of a flying fox service.	Quoted
	Witnessing of testing carried out at the customer's installation by the connection applicant where reasonably required or requested (eg. as the result of the introduction of a parallel generator on a customer's installation).	Quoted

7.4 Type 6 metering services

Type 6 metering and auxiliary metering services are classified as ACS.[8] Type 6 metering services refer to the ongoing maintenance, meter reading and meter data services for Type 6 metering.

It should be noted with Power of Choice taking effect in Queensland on 1 December 2017, we are no longer responsible for providing metering installations as they are subject to contestability. We are only able to provide metering services to existing regulated meters as long as they are in operation. As a result, on 1 December 2017, a number of ACS were either discontinued or had the metering provision component separated from the service with the remaining service components covering the services still performed by us. However, in the Power of Choice exempt areas (Mount Isa-Cloncurry and Isolated supply networks) we remain responsible for the installation and replacement of metering equipment.

Auxiliary metering services are customer-requested metering services provided to individual customers on a non-routine basis. The scope of auxiliary metering services currently involves a number of services including meter alterations, Type 6 non-standard metering services, off-cycle meter reads, meter tests (customer initiated), meter inspections and meter reconfigurations.

The table below summarises the classification of metering services for the 2015-20 regulatory control period. This section addresses metering services that are classified as ACS only.

Table 12 - Classification of Ergon Energy metering services

Metering Type	Description	Charging arrangements

[8] Type 5 meters are not permitted in Queensland.

Metering Type 6 Services	Provision, installation, maintenance, meter reading and meter data services for Type 6 meters.	Metering services charge
Auxiliary Metering Services	Range of customer-requested metering services which are provided to individual customers on a non-routine basis.	Fee-based

Methodology underpinning the Type 6 Metering Charges

Our proposed annual ACS Type 6 metering service charges have been set based on the required revenue each year, the cost allocation weighting between primary, controlled load and solar metering services, and the forecast number of services each year. Further details on the default Type 6 metering building blocks are provided in our 2020-25 Regulatory Proposal.

The relative costs are based on the net present value of forecast ACS Type 6 metering capex and opex, weighted by the cost allocation between primary, controlled and solar metering services.

The annual indicative Type 6 metering charges for 2020-21 included in the TSS are calculated by dividing the revenue requirement for primary, controlled load and solar services by the volume of services in each of these tariff categories. The primary plus controlled load charge assumes one controlled load only. Each additional controlled load would incur an incremental charge. The primary with solar charge incorporates the primary service charge. We are of the view that the proposed charges for annual ACS Type 6 metering services are consistent with the NER, being between the Stand-alone and Avoidable cost of the service.

For subsequent years of the regulatory control period, we have used the formula set out in Figure 2.2 of the F&A to calculate the charges for Type 6 metering services. Note that the value for A_t^i in the formula set out in Figure 2.2 of the F&A has been set to zero for each year of the 2020-25 regulatory control period.

Pricing methodology used to calculate the Auxiliary Metering Services charges

The methodology used to calculate the charges for auxiliary metering services is the same as that used for fee-based services, that is, a cost build-up for the first year of the regulatory control period escalated in subsequent years using the AER's prescribed fee-based formula.

7.5 Public lighting

The provision, construction and maintenance of public lighting assets, as well as emerging public lighting technology and other public lighting services, are classified as a direct control service and further as an ACS under a price cap form of control. The conveyance of electricity to public lights will continue to be classified as a SCS. The list of public lighting services and control mechanisms are listed in Table 13 below:

Table 13 - Ergon Energy's control mechanisms for public lighting services

Public lighting service	Description	Method giving effect to Price Cap	Charging arrangements
Provision, construction and maintenance of public lighting	**Conventional and LED lights:** Non-contributed (EOO): • NPL1 Major: high watt • NPL1 Minor: low watt	Limited Building Block	Public light daily fixed fee

Public lighting service	Description	Method giving effect to Price Cap	Charging arrangements
	Contributed (GOO): • NPL2 Major (high watt) • NPL2 Minor (low watt) **LED only lights:** Contributed (GOO) • NPL4 Major (high watt) • NPL4 Minor (low watt)		
Other public lighting	Construction of new public light services (contributed)	Cost build-up approach	Quoted
	Provision of unique luminaire glare screening or other customer requests	Cost build-up approach	Quoted
	Review, inspection and auditing of design or construction works carried out by an accredited service provider undertaking 3rd party works.	Cost build-up approach	Quoted
	Relocation, rearrangement or removal of existing public light assets and energy efficient retrofit.	Cost build-up approach	Quoted
	Exit fee for the residual asset value of non-contributed public lights when the entire assets (pole, cabling, bracket, luminaire and lamp) are replaced before the end of their expected life	Cost build-up approach	Quoted
Emerging public lighting	New public lighting technologies including trials	Cost build-up approach	Quoted

The proposed new tariffs for LEDs have been developed to account for the specific characteristics of the LED technology. Key features include:

- It is a new technology involving an integrated lamp and luminaire, which together have a significantly longer expected life than conventional lamps
- Ability to include smart electronic features such as self-diagnostics which will reduce inspections and patrols, resulting in lower maintenance costs.

The new proposed NPL4 tariff will apply for assets where customers fund the replacement of the NPL1 luminaire and lamp with an LED and gift the LED luminaire to us. In this circumstance, the associated pole and cabling remain legacy and non-contributed assets owned by us. We will operate and maintain the entire public lighting asset.

Methodology underpinning the charges for the provision, construction and maintenance of public lighting

Our approach to calculating the public lighting tariffs for 2020-25 aligns with the approach used in the 2015-20 regulatory control period. There are also some differences that reflect the introduction of the LED tariffs and the new NPL4 tariff. These differences include:

- The use of separate revenue building blocks for conventional public lights and LEDs

- The treatment and allocation of the LED tax revenue building block to minimise customer impact for LED customers
- The separate calculation of the NPL4 tariff.

The forecast revenue requirement to be recovered for the provision, construction and maintenance of public lighting over the 2020-25 regulatory control period has been determined based on the AER's Post Tax Revenue Model (PTRM) for conventional and LED public lighting assets. Refer to our 2020-25 Regulatory Proposal for further details on the revenue for public lighting services.

<u>Separate calculation of the NPL4 tariff:</u>

In line with customer expectations, we are proposing to introduce a new public lighting tariff, NPL4 that will apply for assets where customers fund the replacement of the NPL1 luminaire and lamp with an LED, but where the associated pole and cabling are legacy and non-contributed assets. In this respect, NPL4 sits between the NPL1 tariff (where we have funded all assets) and the NPL2 tariff (where the entirety of the public lighting assets is funded by customers).

The calculation of the NPL4 tariff is performed separately from the calculation of the NPL1 and NPL2 (which is set out in the following section) but relies on the outcomes of the NPL1 and NPL2 calculations to ensure the tariff accurately reflects the fact that only the luminaire is gifted to us. This means that:

- The operating cost for public lights which are on NPL4 are no different to those on NPL2. The NPL4 tariff can therefore be set no lower than the NPL2 tariff rate
- The capital cost for public lights which are on NPL4 should only reflect the proportion of public light infrastructure owned by Ergon Energy (ie. the pole, bracket, cables etc). The NPL4 tariff can therefore not be set higher than the NPL1 rate
- The tax allocation to be applied to the asset cost pool and operating cost pool must reflect the fact that the customer has only gifted the LED luminaire.

<u>Overarching calculation methodology for NPL1 and NPL2</u>

The approach to calculating the NPL1 and NPL2 tariffs for conventional and LED public lighting is the same, with the only difference being that separate conventional light and LED revenue building blocks are used to determine the respective asset and operating cost pools.

As such, the generic approach used for conventional and LED technologies is set out below:

1. The revenue requirement has been divided into an asset cost pool and operating cost pool
2. For each cost pool a single factor has been used to allocate cost between major and minor lights. Based on historical data, and consistent with the 2015-20 regulatory control period, the factor used to allocate asset pool costs between major and minor lights is set to 1.8, and similarly the factor used to allocate operating pool costs between major and minor lights is set to 1.5
3. A series of charge components are then calculated using the average number of lights in each category for each year of the next regulatory control period as follows:

Table 14 - Public Lighting Charge Components

Price components	NPL 1		NPL 2	
	Major	Minor	Major	Minor
Asset cost pool (original cost)	X	X	-	-

Asset cost pool (refurbishment)	X	X	X	X
Operating cost pool	X	X	X	X

Note that the calculation of NPL4 is set out earlier in this document and as such NPL4 is not included in this table.

4. The sum of cost components produces charges for each year of the next regulatory control period
5. Using the calculated 2020-21 charges for that year, an X factor is calculated so that charges for subsequent years will change by CPI – X each year, consistent with the formula set out in Figure 2.2 of the F&A. The forecast revenue stream produced from the calculated charges from 2020-21 to 2024-25 inclusive equal in net present value terms to the revenue requirement from Step 1
6. The value for A_t^i in the formula set out in Figure 2.2 of the F&A has been set to zero for each year of the 2020-25 regulatory control period

It should be noted that public lighting assets (NPL2) will retain their existing funding arrangement classification once they have reached the end of their economic lives and replaced and funded by us. This is made possible by including in the NPL2 rate the revenue relating to an estimated number of contributed public lighting assets which will be replaced during the 2020-25 regulatory control period.

Exit fees

We propose to develop exit fees on a quoted basis based on the written down value of the public lighting assets where the entire public lights (pole, cabling, bracket, luminaire and lamp) are to be replaced before the end of their expected life in circumstances involving relocations or road diversions.

We propose that the replacement of conventional lights with LEDs will not incur an exit fee for the following reasons:

- Generally upgrading to LEDs will not involve a total asset replacement as many poles, cabling, and brackets will be retained
- The replacement of conventional lights with LEDs is likely to only trigger the replacement of the pre-1990 type brackets still in use, which have little or no residual asset value (as their expected life was less than 28 years)
- This approach will incentivise the uptake of LEDs.

Other public lighting services

It is proposed to charge other public lighting services as a quoted service using the cost build-up formula prescribed by the AER.

7.6 Changes to fee-based services in this updated TSS

Since we submitted our original TSS in January 2019, we have made minor adjustments to our proposed fee-based services to simplify our service offering by reducing the number of service permutations. A summary of the adjustments is provided below:

- The Anytime service option which initially was extended to all fee-based services will now be limited to Re-energisation (for urban and short rural feeder) and Supply Abolishment services (for urban feeder only). The Anytime service option will allow customers to raise a service order requesting that these services be prioritised subject to our crew's availability. The premium service option will incur an extra cost which, for the sake of simplicity, will be set at the same level as the After Hour service option

- The Meter-only service option for the Supply Abolishment service will be charged per NMI rather than per meter as initially proposed. This is to recognise that the incremental cost to remove multiple meters at a single NMI is negligible and a charge per meter may not be justifiable
- The Meter-only service options for the Supply Abolishment service will be consolidated as the costs for the Overhead and Underground options are identical. This will reduce the number of permutations.

APPENDIX A – SELECTED STAKEHOLDER RESPONSES

The table below provides our responses to some of the customer and stakeholder feedback received during our TSS consultation process.

Issues	You Said	We Said
Long Run Marginal Cost (LRMC)	Some stakeholders and customer advocates are concerned with the impact of shifting from volume tariffs to demand tariffs, noting that LRMC is directly linked to the demand charge in cost-reflective tariff.	To address concern about a smooth transition to demand-based tariffs, we have developed assignment rules that mitigate the financial impact small customers may experience when being assigned to a cost-reflective tariff. These are detailed in Section 3.5 of our revised TSS.
	Stakeholders and customer advocates asked whether the use of LRMC is appropriate in a low-growth period.	Basing our tariffs on LRMC is a requirement of the National Electricity Rules (NER). We recognise that the trend in network cost drivers is gradually shifting away from network peak constraints as a result of emerging changes in customer network utilisation and impact of Distributed Energy Resources (DER). We anticipate that demand tariffs will transition to capacity tariffs over time. In recognition of these emerging trends, we are exploring with the proposed capacity tariffs day and evening charging parameters in recognition of the distinct underpinning cost drivers during these periods.
	Tariffs are calculated on the same flawed LRMC estimates.	Please refer to the response above.
	The error of imposing congestion pricing in the absence of congestion is highlighted by the ACCC recommendation in its July 2018 final report 'Restoring electricity affordability and Australia's competitive advantage'	Please refer to the response above.
	Some stakeholders and customer advocates seek efficient tariffs that are reflective of the spare network capacity.	We invite stakeholders to provide further feedback on this issue as part of the AER's TSS consultation process.
	Certain load profiles take place outside the summer months, and yet these loads receive only moderate reduction in costs	Please refer to the response as above. We are also proposing to expand our suite of load control tariffs. We have developed new primary and secondary load control tariffs available to SAC Large customers. These tariffs are detailed in Section 4.2 of our updated TSS.
	Some stakeholders and customer advocates expressed concerns that if the top-up charges of the Package tariffs are too punitive, then business customers may respond by choosing to secure a higher level of network capacity than necessary in order to avoid large cost spikes if they exceed their band.	Package tariffs are no longer included in the TSS for 2020-25.
	Certain stakeholders and customer advocates are open to the distribution	Our current LRMC methodology is detailed in section 6.2 of these Explanatory Notes.

Issues	You Said	We Said
	networks exploring a model that derives an LRMC on a current- and future-focussed network.	During the 2020-25 regulatory control period, we intend to further explore new approaches to incorporate in the LRMC values the impact of emerging technologies on the network.
Customer impact	Some stakeholders and customer advocates support a gradual approach to the introduction of cost-reflective tariffs that include customer research (especially of low income and vulnerable customers) and a data sampling period following installation of a digital meter.	The network tariffs and tariff assignment rules have been developed in our updated TSS in recognition of the need to manage customer impact in our journey towards cost reflectivity.
	Some stakeholders and customer advocates suggest adjustments to the Lifestyle Package to reduce bill shocks.	Packaged tariffs are no longer included in the TSS for 2020-25.
	While seeing the 'Lifestyle Package' tariff as an improvement on the legacy demand-based tariffs, the new tariff is considered as being too complex and likely to result in bill shock.	Packaged tariffs are no longer included in the TSS for 2020-25.
	It is suggested that a safeguard tariff be considered. Such a tariff should be potentially funded from the State's consolidated revenue and not tariffs which are borne by other customers.	We are not in a position to develop such a tariff as it would be unlikely to meet the pricing principles set out in the NER. Financial assistance for customers is a matter for the Queensland Government. We have conveyed the views of stakeholders and customer advocates on this matter to Queensland Government representatives.
DER contribution to network capacity	Stakeholders and customer advocates have commented that embedded micro-generation capacity is forecast to increase. Depending on the rate of increase in this capacity relative to organic demand growth, it is possible that future demand growth is more or less flat indefinitely.	We are carefully considering both the investment required to manage the low-voltage (LV) network performance given the ubiquitous investment in DER that is occurring and the benefits available to enhance capacity of the network.
Supporting customers	Some stakeholders and customer advocates recommend additional support to assist customers to understand the Lifestyle Package.	Package tariffs are no longer included in the TSS for 2020-25.
Tariff Assignment	Some stakeholders and customer advocates expressed concern that mandatory assignment would take a customer's control away.	The principles of equity and fairness continue to underpin our TSS development. Further feedback from stakeholders, customer advocates and customers on this matter is expected to be provided as part of the AER's TSS consultation process.
Equity	Large customer advocates are seeking equitable treatment for their customer user group – in terms of a share of savings from reduced overall revenue requirements and removal of cross subsidies.	The reduced revenue requirement will benefit all customer segments, including large customers.
	Some stakeholders and customer advocates are seeking concrete details around the extent of cross-subsidies as well as on the proposed timing to eliminate these cross-subsidies.	We are committed to implementing new and innovative cost-reflective tariffs. However, the pace of tariff reform needs to take into account customer impacts and the propensity for customers to adopt changes within a reasonable timeframe.

Issues	You Said	We Said
		One way to identify the quantum of cross subsidisation is to consider the savings (or costs) in customer bills as a result of changing tariffs from legacy to cost-reflective tariffs. To assist stakeholders, customer advocates and customers we have included customer impact analysis in this Explanatory Notes document.
Tariff choice	Agricultural advocates have suggested there is an opportunity around a "genuine optimised control load tariff for crops such as sugar cane".	Broad-based primary and secondary load control tariffs are being proposed for SAC Small business and SAC Large customers. We invite stakeholders, customer advocates and customers to provide further feedback on this matter as part of the AER's TSS consultation process.
	Some stakeholders and customer advocates have identified the complexity of understanding the difference between the standing and market offers from each of the retailers in the market. Adding another tariff option in addition to the existing suite of tariffs may escalate the level of complexity of retail market offers.	In offering additional network tariff options, our primary focus is to develop a suite of cost-reflective tariffs which provide customers with choice but also to ensure our network tariffs are relevant to our customers' changing needs. We agree that more needs to be done to reduce the risk of confusion for customers. We intend to work collaboratively with energy retailers to ensure education and information material is developed to support customers to make informed tariff choices.
Determination of peak period	Stakeholders and customer advocates recognise that there are periods where the network faces peak demand constraints. However, they have requested a review of the original summer peak window dimensions.	Package tariffs are no longer included in the TSS for 2020-25.
Jurisdictional Schemes	Some stakeholders and customer advocates noted that we did not include any allowance for the costs associated with jurisdictional schemes such as the Solar Bonus Scheme.	In not pre-empting the Queensland Government's funding decision on jurisdictional scheme amounts post 1 July 2020, we have decided to exclude jurisdictional scheme amounts from the calculation of the indicative rates for the 2020-25 regulatory control period included in this TSS. However, should the Queensland Government change its funding decision of the jurisdictional schemes in 2019, we will incorporate their impact in the indicative rates in the Revised TSS.