

Ergon Energy TSS Explanatory Notes 2020-25

January 2019



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1 Background

These Explanatory Notes accompany Ergon Energy's 2020-25 Tariff Structure Statement (TSS) submission to the Australian Energy Regulator (AER) on 31 January 2019.

The Explanatory Notes provide detailed information on our 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 Ergon Energy 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 both support and context to the TSS document but also supplements the typical supporting documentation of the TSS. The TSS outlines our proposed tariff classes, tariff structures, charging parameters and indicative tariff levels, and demonstrates compliance with pricing principles. It introduces a suite of 'package' tariffs extending from the Lifestyle and Small Business Packages for residential and small business customers respectively, a Business Package for large customers to a Commercial Package for large commercial customers. Collectively these network tariffs have been the core of our many customer engagement sessions as summarised in our *Tariff Structure Statement 2020-25 Engagement Summary*.

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.

Ergon Energy considers that future network tariffs will potentially 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 may, for example, support greater levels of roof top solar and other forms of home load management technologies and markets (e.g. 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. We believe this is best achieved through the introduction of "intermediate" tariffs which represent an evolution of our legacy tariffs.

The introduction of intermediate network tariff options may also address feedback we received throughout our TSS engagement sessions prior to January 2019 on the cost reflective tariffs that we included in our 2020-25 TSS. In particular, some residential and small business customers and stakeholders, who were generally less familiar with demand based tariffs, raised some reservations, and the requirement for digital meters to support these tariffs was also identified as a key issue. More broadly, customers and stakeholders indicated a preference for a new default network tariff that is straightforward to assign and that starts the transition towards more cost reflective network tariff structures (particularly for basic meter customers). Overall customers indicated that we need to balance customer needs in maintaining legacy tariff safeguards while moving to a cost reflective tariff future. A more comprehensive summary of the feedback received thus far and our responses is provided in Appendix B of these Explanatory Notes.

Ergon Energy has commenced developing three intermediate network tariff options for our Standard Access Customers (SAC) to assist their transition to future capacity based cost reflective tariffs. One of these proposed options is the Package tariffs as set out in the 2020-25 TSS. However, at the time of lodging the 2020-25 TSS, the other intermediate network tariff options have not yet been consulted upon and are currently conceptual in nature, reflecting their emergence in the latter stages of the TSS consultation process. In addition, whilst it is intended for an intermediate network tariff option to become the default network tariff for residential and small business customers during the 2020-25 regulatory control period, the tariff assignment arrangements for the intermediate network tariff options have not yet been developed at the time of lodging the TSS.

Ergon Energy has also commenced developing “dynamic response” tariffs for business customers that incorporate load control. During the TSS engagement in 2018 the value of load control was expressed by a number of customer segments, and these tariff options seeking to incorporate this feedback while offering customers additional choice and control options that suit their particular business need.

Section 2 of this Explanatory Notes document provides more details on the intermediate network tariff options and dynamic response tariff options, and the associated tariff assignment arrangements which we would like to further develop and consult upon throughout 2019 as part of the AER’s TSS consultation process. We would welcome the opportunity to include intermediate network tariff options and dynamic response tariffs as part of the Revised TSS in December 2019, subject to the AER’s TSS assessment and consultation process.

1.2 How to Read this document

To ensure our TSS is fully compliant with the requirements of the NER, our TSS contains only those tariffs that were introduced to customers as part of our customer engagement process – being our legacy tariffs and the Package tariffs as set out above. Section 2 of these Explanatory Notes provides a strategic view of potential intermediate 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.

Appendix A of these Explanatory Notes sets out the intermediate network tariff options that Ergon Energy is still developing at the time of lodging the 2020-25 TSS in January 2019. The intermediate network tariff options set out in Appendix A have not yet been fully developed and time has not allowed for these tariff structure options to be consulted upon or developed to a stage consistent with inclusion in a compliant TSS.

Ergon Energy is seeking to continue to work with the AER and stakeholders on these options, but notes the opportunity for the proposed network tariff options to become part of the next phase of the discussion of the optimal suite of network tariffs within the TSS is dependent on the scope of TSS review and consultation sought by the AER.

Chapter 3 sets out how Ergon Energy’s 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 its network planning and DM strategies.

Finally Chapters 4 to 7 provide additional information in support Ergon Energy’s 2020-25 TSS.

1.3 Next steps and on-going consultation

The AER will consult on Ergon Energy's TSS 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 Ergon Energy's 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 Ergon Energy via tariffs@energyq.com.au

2 Overarching tariff strategy

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. While we anticipate an increase in the relevance of capacity based tariffs in support of emergent technology and new customer needs in the future, we consider tariffs that provide tariff signals about network peak investment remain a critical first step in this customer journey. As the role of the network changes from a simple deliverer of energy to an enabler of an ecosystem of distributed energy resources, Ergon Energy considers its current overarching tariff strategy is at a cross-road and, therefore, needs to cater for both aspects through a mix of innovative cost reflective tariff options that include time of use demand and capacity charging elements.

2.1 Mandate for Tariff Reform

The structures of most Ergon Energy 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, Ergon Energy also listens to its 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, and
- They are concerned about affordability.

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 before reaching the desired outcomes.

2.2 Our current position (2020-25 TSS)

Our tariff reform journey started with our 2017-20 TSS with the introduction of time of use demand-based tariffs made available to our low voltage (LV) residential and business customers. However these tariffs have had limited appeal to mass market customers, in part due to the majority of small customers being on basic meters and their lack of familiarity with the new concept of demand.

As part of our consultation for the 2020-25 TSS, our focus was predominantly on the introduction of a suite of new tariffs, namely the Lifestyle Package, as another step towards fully cost reflective tariffs while, at the same time, using energy as a proxy for demand in the Summer Peak Window (SPW). This tariff also provides customers a choice in their level of network usage (Band) and therefore network bill. The Lifestyle Package does require an element of customer engagement to select the most efficient band for their needs, an item that has caused concern amongst some customer groups. It also requires Type 1-4 metering, which is still being deployed across Ergon Energy's network.

2.3 Future State – Capacity Based Tariffs (2025 and beyond)

Demand tariffs are considered current industry practice. However with the changing technology environment, we anticipate demand tariffs will transition to capacity tariffs over time.¹

Capacity tariffs are based on the premise that peak demand driving upstream network investment will become a lesser issue as customers continue to invest in ubiquitous levels of distributed energy resources and both customers and the network businesses access affordable and smarter technology.

Under this scenario there would be a bias towards the network providing adequate capacity rather than facing upstream network peak driven constraints. We are continuing to explore how to progressively migrate to capacity tariffs in future TSSs.

2.4 Tariff Pathway Options

We recognise the potential future state for our networks tariffs lies with capacity based tariffs, and that there is a need for intermediate network tariffs to be introduced in the 2020-25 regulatory control period to commence the network tariff journey towards this future state.

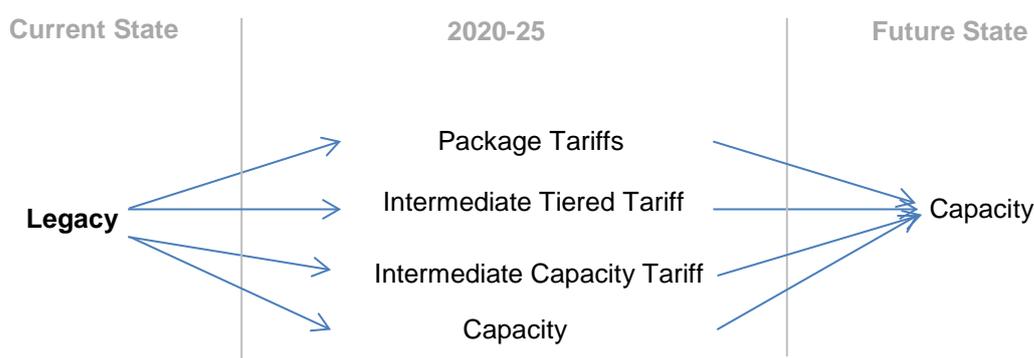
We consider that the Package tariff suites set out and consulted upon in the 2020-25 TSS is one of the potential intermediate network tariff options that may be available for the 2020-25 regulatory control period. However we have commenced developing two other options which, at the time of submitting the TSS, we have not yet finalised nor consulted upon. The full set of intermediate network tariff options that we are considering are set out below:

- Intermediate network tariff option 1 – the Package tariffs as set out in the 2020-25 TSS
- Intermediate network tariff option 2 – the Intermediate Tiered tariff as set out in Appendix A
- Intermediate network tariff option 3 – the Intermediate Capacity tariff as set out in Appendix A

This presents a number of possible pathways towards the capacity based tariff future state, framed around which intermediate network tariff option(s) are adopted for the 2020-25 regulatory control period, as set out in the figure below:

¹ The structure of the future capacity tariff remains un-finalised at the time of submitting the 2020-25 TSS and Ergon Energy would expect its development and final shape to occur over the forthcoming regulatory control period in light of further analysis of the underlying trends in network cost drivers and as a result of further stakeholder engagement.

Figure 1 - Possible Tariff Pathways



The 2020-25 TSS has been positioned based on the Package tariffs being the intermediate network tariff options for the 2020-25 regulatory control period. However we would like to consult and engage with customers on whether the Intermediate Tiered tariff option and/or the Intermediate Capacity tariff option, as set out in Appendix A, could be introduced in the 2020-25 regulatory control period in place of or in conjunction with the Package tariffs. We would also like to consult and engage with customers on the tariff assignment arrangements for the intermediate network tariff options contemplated in the tariff pathways depicted above.

Another possibility is to bypass the need for intermediate network tariff options altogether in the 2020-25 regulatory control period by bringing forward the introduction of future state capacity tariffs. The future state capacity tariffs would need to be developed and consulted upon with customers during 2019, as these tariffs are undefined at the time of submitting the 2020-25 TSS.

We therefore welcome the opportunity to consult upon and engage with customers and stakeholders on the proposed intermediate network tariff options, tariff assignment arrangements and tariff pathways in the 2020-25 regulatory control period, as part of the AER's TSS consultation process during 2019.

2.5 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 seasonal, demand/capacity based, time of use and day of week tariffs. Currently almost all Ergon Energy residential and small business mass market customers (using less than 100MWh per annum) are familiar with tariffs that consist of a daily charge plus a rate for energy consumption regardless of when it is used.

In the 2017-20 TSS, Ergon Energy 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 are challenged by the concept of demand, particularly when overlaid with other complexity in language and determining billable quantities
- Retailers find it a challenge to get customers comfortable with these first generation time of use demand tariffs and to adopt them, and
- Stakeholders generally struggle to communicate this reform as a step forward.

This customer and stakeholder feedback is relevant to both demand and capacity tariffs.

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.

While retailers recognise where the NER is driving the market, there are no compelling business drivers supporting the changes for retailers. Essentially retailers are evaluating a commercial decision and at the moment there is limited commercial foundation for change.

With the Lifestyle and Small Business package, Ergon Energy has developed a simpler approach for signalling LRMC through demand tariffs into a market facing structure. Through our customer engagement process, this approach has generally been positively received by stakeholders. Effectively the structure allows customers to be presented with a network tariff that consists of a fixed monthly charge and a dollar per kWh rate for electricity used. The tariff resembles the existing fixed plus volume structure.

The key break-through is that the proposed structure allows the conversation with the mass market customer basis to continue to be on an energy basis and framed within concepts with which they are familiar.

At the network level the structure is called the “Lifestyle Package” for residential customers. The language and narrative supporting this tariff structure reflects a reset in the network tariff thinking and engagement by Ergon Energy. The linkage of this new structure to individual customer lifestyle and choice is strong and provides the opportunity for our customers to align the package they choose based on their lifestyle (including preferences for choice, control and personal budget) and their technology and services dispositions.

The focus of the Lifestyle Package is on the mass market, but Ergon Energy has replicated the concept for business customers by developing the Small Business, Business, and Commercial packages. For business customers rather than lifestyle, the key focus is on improving business productivity.

By nominating a demand or selecting a band associated with a demand, business customers can control and smooth their electricity distribution network bill. The principle of spreading the LRMC across 12 months with additional charges for any further use of the network in the SPW underpins the tariff structures for all network tariff classes.

During customer engagement, customer advocates raised the issue of large numbers of customers not being able to access digital meters in the short and medium term. Concern was also raised about the need for a cost reflective default network tariff option that was unambiguous yet familiar to customers. A number of intermediate network tariff options are being developed which are, in part, aimed at addressing these concerns but also recognising the emerging trends in network cost drivers as a result of changing customer network utilisation. Appendix A of this Explanatory Note provides further details of the Intermediate network tariff options being considered and developed at the time of submitting the TSS.

2.6 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

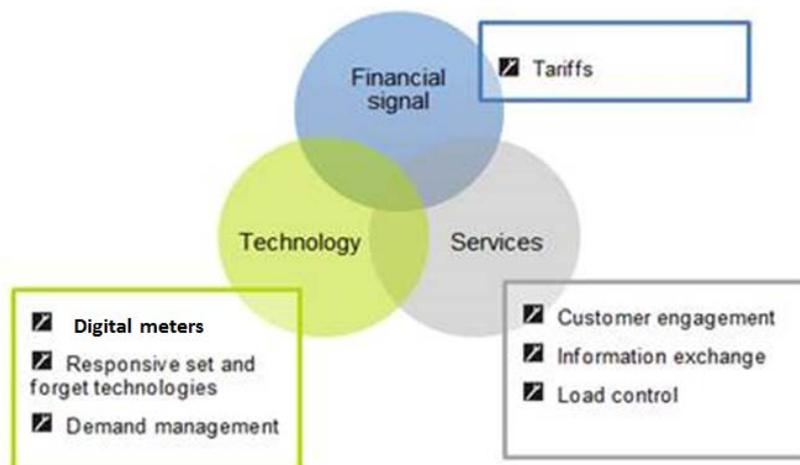
uptake of cost reflective tariffs. They have also confirmed the need for customer education and information as key elements to accelerate tariff reform.

For these reasons and in particular because of the potential customer impacts from moving existing customers to cost reflective tariffs, we consider a voluntary introduction of cost reflective tariffs is the most suitable approach for existing customers at this time.

2.7 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. The figure below illustrates the new market environment in which network tariff reform is only one element of the value chain.

Figure 2 - Market environment



Ergon Energy recognises 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.

Ergon Energy acknowledges 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

Ergon Energy's 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 Ergon Energy's 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.

Ergon Energy recognises the pivotal role network tariff reform plays within the wider business. For this reason, Ergon Energy's network tariff strategy has been carefully developed with a view to align with its corporate strategy, customer strategy and Demand Management (DM) strategy in order to achieve more efficient outcomes and meet customer expectations. Such a coordinated approach will ensure Ergon Energy will deliver our commitment to deliver services our customers need.

3.1 Corporate strategy

As part of the Energy Queensland Group, Ergon Energy has 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.

Ergon Energy's 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 below.

Figure 3 - 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 the co-operation between Ergon Energy 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 Ergon Energy's 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 below.

Table 1 - Customer Principles

Customer Principle	Relationship to Tariff Strategy
Know our Customers	<ul style="list-style-type: none">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	<ul style="list-style-type: none">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	<ul style="list-style-type: none">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

At Ergon Energy, network planning, demand management (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 Ergon Energy's 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, and
- 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 network investment. Whilst in the future we anticipate network investment will not be exclusively driven by seasonal customer driven demand, at present if Ergon Energy is to continue to reduce network tariffs in real terms, we must look at a variety of avenues to manage and/or reduce peak loads.

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 Ergon Energy's 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 over the long term, deferring the need to build more 'poles and wires'. We plan to support the introduction of network tariff reform with dynamic incentives that combine load control and locational demand management programs.

As discussed earlier, our network tariff strategy seeks to move towards cost reflective network tariffs (i.e. begin implementing tariff reform) as soon as possible. While delivering a raft of additional customer benefits, network tariff reform will begin to signal to customers the true value of above-average use of the network, especially during peak periods, such as during the SPW. While correcting some cross-subsidies that currently distort network tariffs, this signalling is intended to motivate customers to limit their peak loads, and if not, contribute more to the cost of the network required to service those peaks.

Our DM programs complement both a demand tariff scenario and a capacity tariff scenario providing a mitigant in instances where network constraints or congestion would 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.

- Ergon Energy has 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
- Ergon Energy also has 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
- While load control tariffs will still be available in conjunction with Lifestyle Package tariffs, we anticipate the load under control available from load control tariffs will likely decrease, and that this will lessen our ability to provide 'hard' control that is exercised during heat waves or similar emergency events. However, this loss will in part also be compensated for by the Lifestyle Package tariffs, as they will provide a strong signal for customers to reduce demand during the SPW. In a sense, this is indirect load control as it will be customers who choose whether and to what degree they reduce their network usage during peak periods
- In addition, with customers increasingly connecting Distributed Energy Resources (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.
- Ergon Energy believes 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, Ergon Energy is 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

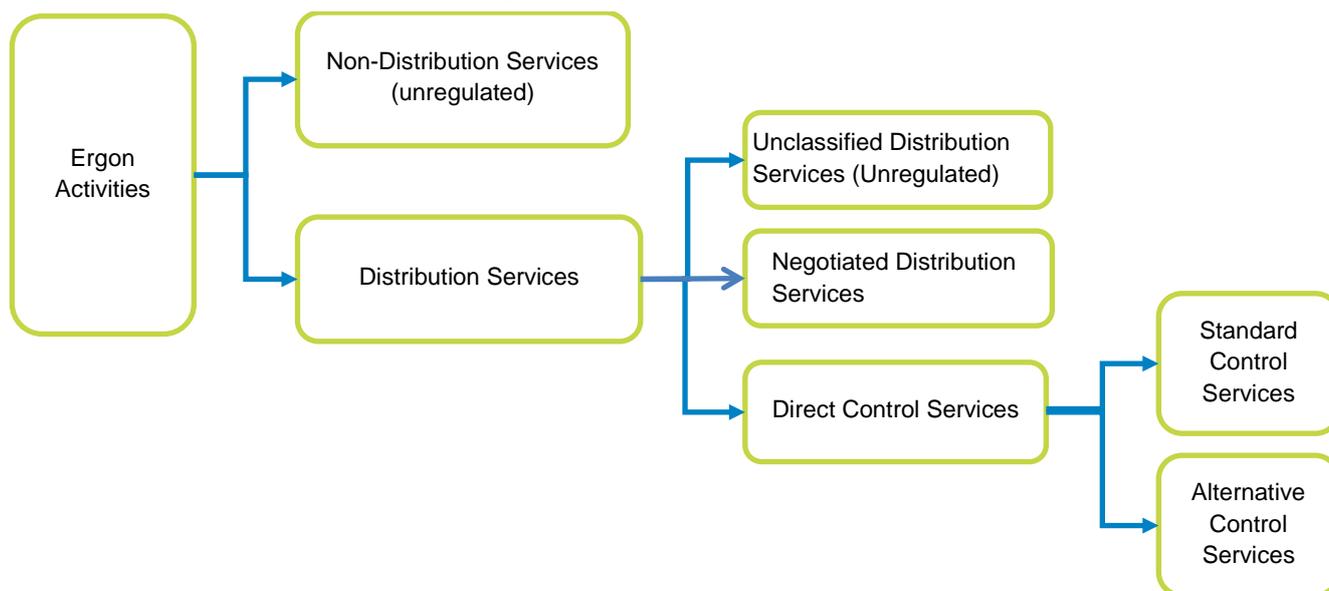
The AER determines how Ergon Energy's distribution services are classified and in turn the nature of the economic regulation. This is important as it determines how tariffs will be set and how charges are recovered from customers.

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

Ergon Energy's 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 below.

Figure 4 - Classification of Ergon Energy's distribution services



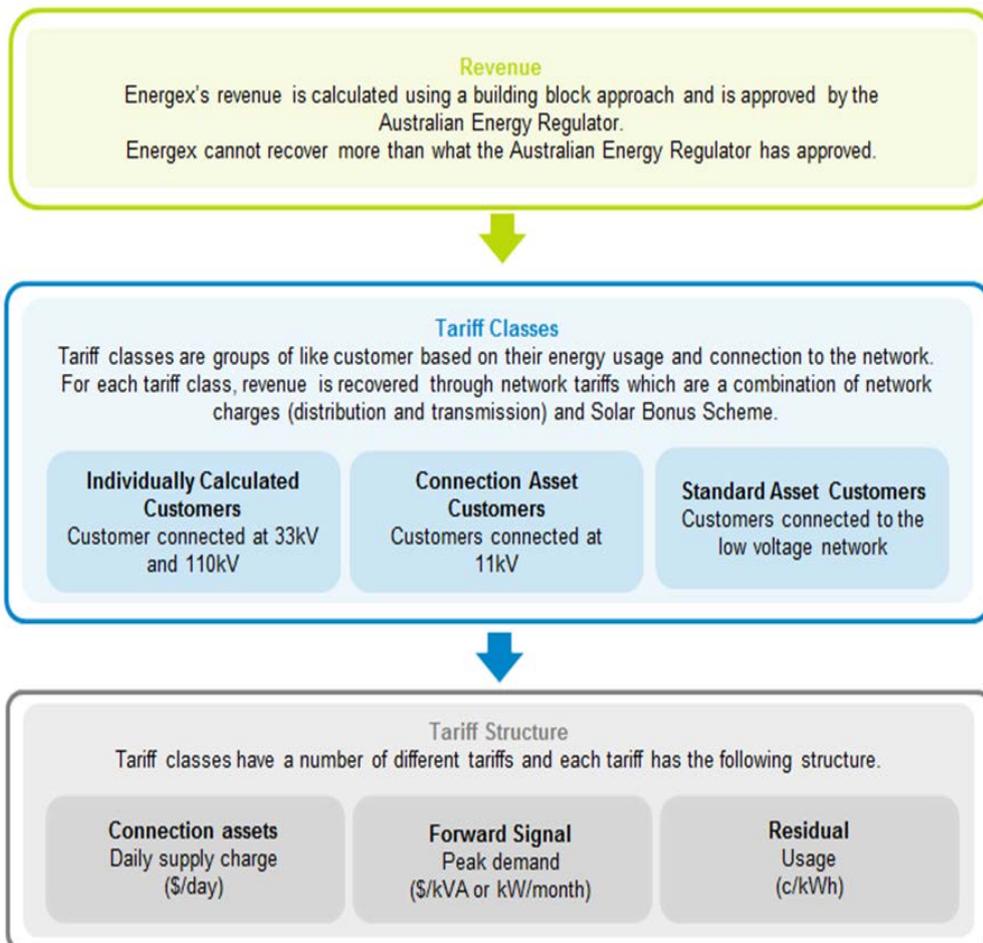
There are three primary sources of revenue that Ergon Energy recovers through network use of system (NUOS) charges:

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

Ergon Energy recovers its 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 Ergon Energy can earn. Instead, they determine how much revenue is recovered from particular customer groups.

Ergon Energy charges NUOS charges to electricity retailers. Customers may not see Ergon Energy’s network charges itemised on their retail electricity bill, as the retailer may incorporate Ergon Energy’s network charges in 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.² Ergon Energy’s allocation of allowed revenue is illustrated in Figure 5 below.

Figure 5 - 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 the charges Ergon Energy can apply for these services, known as ACS, are regulated by the AER.

4.2 Components that make up our tariff schedule

Ergon Energy’s network tariff schedule is underpinned by key concepts, including tariff classes, tariff structures, and charging parameters and levels.

The sections below provide further explanation of these concepts as they apply to Ergon Energy.

² Queensland Competition Authority's Regulated Retail Electricity Prices for 2018-19, May 2018.

4.2.1 Tariffs and tariff classes

Ergon Energy has over 750,000 residential and business customers, with a range of different characteristics. Ergon Energy groups 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, Ergon Energy differentiates 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 Ergon Energy's 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
- Capacity charge
- Monthly Band supply charge (also known as fixed charge which varies depending on nominated network access band), and
- Summer Peak Top-Up 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 \$/day charge applied regardless of usage to each energised connection point.

There are a number of 'fixed' costs that Ergon Energy 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. 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 costs that are not recovered from the daily/monthly supply charge. This charge remains the same regardless of the time of the day/month.

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

As noted earlier, demand is currently a key driver of future network capacity augmentation (although we note that, in the future network, investment will not be exclusively driven by seasonal customer driven demand). Network expansion becomes necessary where there is a high likelihood of demand exceeding available capacity.

Demand charges are reflective of augmentation costs associated with customer demand activity. 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 at a point in time, rather than usage measured over a period of time. This is the key difference between a usage and demand charge.

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).

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 of augmenting the capacity of the network to meet future demand. This means that customers who place more pressure on the network by using more electricity at peak times are charged more. As a result, these charges encourage customers to optimise their use of network capacity during peak hours.

4.3.4 Capacity charge

This charging parameter is similar to a monthly maximum demand charge. The capacity charge reflects 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.

This is a monthly charge calculated as a dollar per kilovolt ampere (\$/kVA) rate for the network capacity provided for a connection point. These charges are currently applied to the maximum half hourly kVA power reading that occurred at a connection point in the 12 months prior to the bill being calculated. Similar to demand charges, capacity charges are currently only incorporated in the network tariffs of large business customers.

As noted in earlier sections of the Explanatory Notes and outlined in Appendix A, Ergon Energy is exploring the introduction of an intermediate capacity tariff option for small LV customers.

4.3.5 Band charge

This charging parameter is similar to the daily supply charge as it represents a network access allowance fixed charge (in \$/month) but provides customer choice to nominate a Band to support customer needs. Bands and associated Band network access limits are described in Section 5.3 of our TSS.

4.3.6 Summer Peak Top-Up charge

Linked to the Band Charges in section 4.3.5, should the customer need additional network capacity in the SPW, they can top up their package for that month at rates that are comparable with the charges incorporated directly into the bands. The SPW is represented as a rate (\$) per kWh consumed above the customer's nominated access band within a month during the SPW described in Section 5.4.1 of our TSS. There is no top-up charge for use of the network anytime outside of the SPW.

4.3.7 Excess kVAr charge

Ergon Energy 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, and
- 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.

Ergon Energy 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 Ergon Energy recovers, 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 networks Ergon Energy 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 Ergon Energy proposes 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 for direct control services are a member of at least one tariff class.

Ergon Energy’s tariff classes group retail customers on the basis of their voltage level and 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, Ergon Energy’s 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 including regional distinctions it is proposed to rationalise tariff class arrangements within Ergon Energy. The proposed set of tariff classes for Ergon Energy 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	Ergon Energy		
	South East	East	West	Mount Isa
ICC	✓	✓		
CAC	✓	✓	✓	✓
SAC	✓	✓	✓	✓

Where:

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

- ICC are customers coupled to the network at 110kV 66kV 33kV 22kV.

From 1 July 2020, Ergon Energy is proposing to reduce the number of tariff classes by removing 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 align Ergon Energy's tariff class structure with that of Ergon Energy, resulting in a 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 or have the option to opt-in to the Commercial Package tariff.

It should be noted that in 2015 the AER accepted Ergon Energy's proposal to consolidate its tariff classes as part of the 2015-20 regulatory proposal.

5.2 Implementation of tariffs

Ergon Energy's network tariff implementation strategy over the 2020-25 regulatory control period is to offer new cost reflective tariffs for the CAC and SAC tariff classes on an opt-in basis. Ergon Energy does not propose to remove any legacy tariffs during the 2020-25 regulatory control period. Under these proposed arrangements, existing customers on legacy tariffs will be minimally impacted and may elect to be assigned to a cost reflective tariff. Current legacy tariffs that are retained as default tariffs will be accessible to all customers while legacy tariffs that are grandfathered will be accessible to existing customers only. It is anticipated that grandfathered tariffs will be replaced by cost reflective tariffs over time.

Ergon Energy's 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 already cost reflective and does not require any further changes.

CAC tariff implementation strategy

Ergon Energy is proposing to introduce a new cost reflective Commercial Package for CAC customers in July 2020. The Commercial Package is a seasonal ToU demand tariff and is outlined in this section. It is proposed that this tariff will be the default tariff for this customer class and that all new CAC customers would be assigned to it. It will also be available to existing CAC customers. It is further proposed that the current suite of anytime demand and ToU demand tariffs will be available to existing customers to enable management of customer impact as the transition to fully cost reflective tariffs progresses.

Table 4 - CAC tariff implementation strategy

Tariff	2020-25 Status	Availability
Commercial Package	Default	New and Existing Customers
CAC 66kV	Grandfather	Existing Customers
CAC 33kV	Grandfather	Existing Customers
CAC 22/11kV Bus	Grandfather	
CAC 22/11kV/Line	Grandfather	
Seasonal ToU Demand 66/33kV	Grandfather	
Seasonal ToU Demand 22/11kV Bus	Grandfather	Existing Customers
Seasonal ToU Demand 22/11kV Line	Grandfather	Existing Customers
Note: This applies across the Ergon Energy East, West and Mount Isa pricing zones.		

SAC Large tariff implementation strategy

Ergon Energy is proposing to introduce a new cost reflective Business Package for SAC Large customers in July 2020. The Business Package is a seasonal ToU demand tariff and is outlined in this section. It is proposed that this tariff will be the default tariff for this customer class and that all new SAC Large customers would be assigned to it. Assignment to the Business Medium or Business Large versions of the Business Package tariff is based on annual consumption. The tariff will also be available to existing SAC Large customers. It is further proposed that the current suite of anytime demand and ToU demand tariffs will be available to existing customers to enable management of customer impact as the transition to fully cost reflective tariffs progresses.

Table 5 - SAC Large tariff implementation strategy

SAC User Group	Tariff	2020-25 Status	Availability
SAC Large	Business Medium Package	Default	New and Existing Customers
	Business Large Package	Default	New and Existing Customers
	Demand Large	Grandfather	Existing Customers
	Demand Medium	Grandfather	Existing Customers
	Demand Small	Grandfather	Existing Customers
	Seasonal ToU Demand	Grandfather	Existing Customers
Note: This schedule applies across Ergon Energy's East, West and Mount Isa pricing zones.			

SAC Small Residential and SAC small business tariff implementation strategy

Ergon Energy is introducing a new tariff option for SAC Small residential customers in 2020-25. The Lifestyle Package is a cost reflective seasonal ToU tariff which offers enhanced choice and control and is predicated on customers installing a type 1-4 meter. The existing IBT will remain as the default for SAC Small Residential customers.

Ergon Energy is also introducing a new tariff option for SAC Small business customers in 2020-25. The Small Business Package is a cost reflective seasonal ToU tariff which offers enhanced choice

and control and is predicated on customers installing a types 1-4 meter. The existing IBT tariff will remain as the default for SAC Small Business customers.

Table 6 - SAC Small tariff implementation strategy

SAC User Group	Tariff	2020-25 Status	Availability
SAC Small Residential	Lifestyle Package	Opt in	New and Existing Customers
	IBT Residential	Default	New and Existing Customers
	Seasonal ToU Energy	Grandfather	Existing Customers
	Seasonal ToU Demand	Grandfather	Existing Customers
SAC Small Business	Small Business Package	Opt in	New and Existing Customers
	IBT Business	Default	New and Existing Customers
	Seasonal ToU Energy	Grandfather	Existing Customers
	Seasonal ToU Demand	Grandfather	Existing Customers

Note:

This schedule applies across Ergon Energy's East, West and Mount Isa pricing zones.

Secondary tariffs implementation strategy

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

Ergon Energy is 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, Ergon Energy's strategy is to offer relevant load control services to customers that complement its existing and proposed demand tariffs.

Secondary tariffs volume controlled and volume night controlled will remain unchanged until 30 June 2025 and will continue to be available to customers on legacy tariffs. These secondary tariffs can also be accessed by customers on the Package tariffs and any of the proposed intermediate network tariff options.

5.3 Rationale for the new 2020-25 tariff structures

The term 'tariff structure' is 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 charge
- Network band allowance, and

- Summer peak top up charges.

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 Ergon Energy's approach in setting the charging parameters for the new cost reflective tariffs.

5.3.1 Lifestyle Package and Small Business Package

The structure of the Lifestyle Package and Small Business Package is:

- Network access allowance (\$/month)
- Summer peak top-up (\$/kW/month), and
- Usage flat (\$/kWh).

In this tariff the network access allowance and the summer-peak top-up charges are used to recover LRMC. Both these charge relate to customers maximum use of the network during the SPW.

Residual revenue is then recovered through both the usage charge and a fixed base component which is bundled into the monthly network access allowance.

5.3.2 Business Medium and Business Large (for Standard Asset Customer (SAC) – Large)

The structure of the Business Medium and Business Large Package tariffs are:

- Nominated Demand Charge (\$/month)
- Top-up (\$/kVA/month), and
- Volume (\$/kWh).

In these tariffs the nominated demand charge and the top-up charge are used to recover LRMC. Both these charge relate to customers maximum use of the network during the SPW. Residual revenue is then recovered through both the volume charge and a fixed base component which is bundled into the monthly nominated demand charge.

Ergon Energy also proposes 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 demand.

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.

In light of this, to enable the implementation of kVA billing for all SAC Large customers from 1 July 2020, it is proposed that in circumstances where customer metering does not support the explicit metering of kVA demand, that customers' maximum kW demand billing data will be converted to kVA, and the kVA based charges would then be applied to this converted demand data. This conversion would be based on the application of a single DNSP-determined power factor which is applied uniformly to all customers. This approach will allow Ergon Energy to proceed with the

adoption of metered kVA pricing for SAC Large customers without requiring these customers to change metering infrastructure on 1 July 2020 if kVA metering capability is not available at that time. The proposed power factor adjustment will be determined each year by Ergon Energy and included in the annual Pricing Proposal submissions. In 2020-21 it will be set at the LV compliant power factor of 0.9.

This will result in a single set of kVA prices being deployed with the adjustment to kVA from kW, when required, being incorporated in the billing process.

Finally, it should also be noted that the proposed change to kVA aligns with Ergon Energy's approach implemented during the 2015-20 regulatory control period.

5.3.3 Connection Asset Customers (CAC)

Ergon Energy is proposing to introduce a new Commercial Package available to all Connection Asset Customers (CAC).

The tariff structure of the Commercial Package is as follows:

- Fixed charge (\$/day)
- Volume charge (\$/kWh)
- Nominated Demand charge LRMC over 12 months (\$/kVA/month), and
- Seasonal demand charge LRMC over the SPW (\$/kVA/month)

The rationale for setting the elements forming part of the charging parameters for the new CAC tariff is provided below.

Daily fixed charge for the proposed Commercial Package

Ergon Energy explored the option of an averaged daily fixed charge for both DUOS and DPPC during our engagement process for the 2020-25 TSS. The averaged charge considered combined a capital charge and operation and maintenance charge. The customer impacts associated with this reform could not be reasonably managed at the DUOS level. It is therefore proposed to retain the DUOS daily fixed charge being individually calculated for each customer each year. However, it is proposed however to apply average charges to the DPPC as this can be achieved within a managed customer impact approach.

Nominated demand charge for the proposed Commercial Package

Ergon Energy proposes to introduce the concept of a nominated demand charge as part of the Commercial Package. This charge enables the customer to spread the LRMC associated with the demand they nominate over 12 months and is aimed at providing bill certainty and better budget control. This charge would apply at both the DUOS and DPPC level.

Seasonal demand charge for the proposed Commercial Package

This charge only applies in the SPW where the actual demand is greater than the nominated demand. The charge is LRMC based. This charge would apply at both the DUOS and DPPC level.

5.3.4 Individually Calculated Customers (ICC)

Ergon Energy does not propose to initiate any further changes to the current structure of ICC tariffs during the 2020-25 regulatory control period. The tariff structure is as follows:

- Supply charge (\$/day)
- Volume charge (\$/kWh)
- Capacity charge (\$/kVA/month), and
- Demand charge (\$/kVA/month).

5.3.5 Rationale for selecting the Summer Peak Windows

A key defining parameter of the Lifestyle Package, Small Business Package, Business Package and Commercial Package tariffs is the time periods during which customers are exposed to the peak demand component of the tariff. These periods should align with those times when demand on network assets is high and by extension when additional customer demand is more likely to contribute to peak demands that are going to influence asset capacity augmentation decisions.

Once determined, these time periods establish the SPWs during which the network peak capacity tariff signal is “turned on” in the demand tariffs.

To broadly define the SPWs, analysis of Zone Substation (ZS) data was undertaken that identified those times when ZS demand was within 5% of the ZS annual maximum half hour demand.

Summer Peak Windows

The SPWs are detailed in the table below. Different SPWs apply to the residential and non-residential customer segments.

Table 7 - Summer Peak Window

Customer Segment	Time	Days	Month
Residential	4pm-9pm	Mon-Sun	Dec-Feb
Non-Residential	12.30pm-8pm	Mon-Fri	Nov-Mar

Trade-offs / tensions in Determining SPWs

The optimal selection of SPWs involved us making choices and judgement to address a number of tensions, future uncertainties and risks that needed to be considered. The key considerations are summarised below in the table below:

Table 8 - Trade-offs / tensions in determining SPWs

Risk	Choice/Issue	Pros	Cons
High demands occurring outside of the peak period which are not subject to the peak tariff signal	Increase the duration of the SPW	Reduces the chances of an actual peak not being subject to the peak tariff signal	Peak tariff signal becomes diluted and weak, compromising the level of customer response achievable within a narrower peak

Risk	Choice/Issue	Pros	Cons
			<p>Period becomes too large for customers to respond to</p> <p>A lot of the customer response that is achieved is at 'peak' times that are of no value to the network</p> <p>Customer engagement feedback has indicated a preference for shorter SPWs</p>
Tariff induced peaks occurring at the start or end of the daily off-peak period	Start the time of day period earlier and finish later to incorporate the shoulder into the SPW	Increases the size of the demand buffer between current maximum demand and off-peak maximum demand	Similar to the Cons above - longer peak dilutes the strength of the peak pricing – reducing risk trade-off is it weakens the effectiveness of the tariff's signalling during the actual peak
Peaks occurring in months not part of the SPW (e.g. winter peaks or non-summer load supply assets)	<p>Include November/ March in the SPW</p> <p>Exclude major non seasonal supply assets (e.g. Ergon Energy ICC load)</p>	Exclusion of winter aligns with planning/forecasting focus on non-winter demand (i.e. is forward looking)	<p>Reduces the calculated 'efficiency' of the SPW as the current non summer peaks are assessed as not covered. (backward looking)</p> <p>Including November and March decreases the customer peak tariff in Dec, Jan, Feb. This will reduce the response in those months which are of most benefit to the networks</p> <p>Customer engagement responses prefer shorter peak windows.</p>
The TSS "locks-in" the SPW in 2018 for the period 2020-25. The SPW may get out of phase with actual demand during the 2020-25 period, e.g. as a result of emergent technology uptake or strength of response to the tariff peak demand signal	<p>i) Implement variation mechanisms in the TSS to vary the SPW within the regulatory control period (e.g. propose the ability to specify a new SPW definition in the Annual Pricing Proposal after two years of demand profile data is available showing a material, permanent shift in peak demand)</p> <p>ii) Lengthen the SPW to</p>	<p>Allows the SPW to be more tightly specified and therefore more efficient because the risk of peak shift is only being addressed if it actually occurs, not pre-emptively</p> <p>If peak shift does occur, SPW can be aligned with new peak periods to ensure network tariffs remain economically efficient</p>	<p>Potentially impacts on customers and investors certainty regarding changes to tariffs and tariff structures out to 2025.</p> <p>Agreement required defining an appropriate mechanism to trigger change.</p>

Risk	Choice/Issue	Pros	Cons
	mitigate risk	and send accurate tariff signals	
Basing the SPW on a customer class' ability to avoid the peak demand charges	Base SPW on response capability of customers rather than the period where demand impacts network augmentation decisions	Responds to some user group customer engagement feedback	<p>Loses alignment between the tariff SPW and customer response which will positively impact on future capacity planning decisions</p> <p>Introduces new cross subsidies and reduces network efficiency and utilisation</p> <p>Unlikely to be NER compliant as tariff signalling on this basis is not permitted</p>

Review of Peak 'Coverage' of SPW Options

It is also possible to assess how well the SPW covers historic peak zone substation usage, by determining the total proportion of peak instances that occur during the SPW, where a peak instance is defined as occurring when demand at the zone substation exceeds 95% of the zone substation highest recorded annual ½ hour demand. The table below summarises the SPW coverage outcomes.

Table 9 – Review of Peak Coverage of SPW Options

User Group	SPW	Coverage ³
SAC Small Residential – Ergon Energy		
	Dec, Jan, Feb, all days, 4pm-9pm	57%
SAC Small Business and SAC Large – Ergon Energy		
AS&P Workshop Outcome	Nov, Dec, Jan ,Feb, Mar weekdays 12.30pm –8pm	89%

The coverage metric is a useful indicator of the alignment of the SPW with when maximum demands have occurred historically.

As discussed in Table 8, a number of additional factors also need to be considered. For example, finishing the residential SPW in Ergon Energy at 8pm instead of 9pm, as suggested in some customer engagement responses, only slightly reduces peak coverage. On its own, the coverage metric suggests making this change to the SPW would not materially affect the efficiency or accuracy of the peak tariff signal. However in terms of the risk of tariff induced secondary peaks, the risk increases significantly as a result of the 8pm to 9pm shoulder/buffer being removed. This additional risk is not captured in the coverage metric.

³ Based on 2016, 2017 and 2018 Zone Substation data.

Likewise assessing changing the non-residential SPW to 4pm-9pm based on future solar generation does not capture network exposure to the impact of interruption to solar supply at times of high network demand on network capacity augmentation planning, or the distributional and tariff effects if this option was adopted.

The proposed SPWs reflect the balance of quantification based on historic demand analysis, relevant subject matter expertise and risk mitigation.

5.3.6 Locational Charges

Ergon Energy is 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, Ergon Energy will support the SCS tariffs with a suite of customer enabling mechanisms incorporating Technology, Education, Dynamic initiatives and Information (TEDI), 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 the Ergon Energy 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 Ergon Energy accepts 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.

Ergon Energy proposes 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

Ergon Energy considers the usage profile of customers in the assignment to tariff classes. In accordance with clause 6.18.4(a)(3) of the NER, Ergon Energy does 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. Ergon Energy's 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, Ergon Energy has 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 Ergon Energy's 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 Ergon Energy's 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, Ergon Energy emphasises 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 Ergon Energy's control in relation to how they consume electricity.

6 Compliance with Pricing Principles

In complying with the pricing principles, Ergon Energy 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 Ergon Energy's efficient costs of providing network services in a way that minimises distortions to the tariff signals
- Ergon Energy 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, and
- 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 circumstances".⁴

Figure 6 - Pricing principles



⁴ Deloitte Access Economics, Residential electricity tariff review – Report commissioned by the Energy Supply Association of Australia, Final Report, 22 January 2014.

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

- **Economic efficiency** – network tariffs signal the economic costs of providing distribution services to the market
- **Customer impacts** – Ergon Energy manage changes that are expected to affect customer bills for example progressive deployment of changes to avoid bill shock
- **Simplicity and transparency** – Ergon Energy offer customers a clear and simple tariff structure
- **Flexibility** – Ergon Energy 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, and
- **Sustainability** – supports the energy tri-lemma strategy, and
- **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:

- Protection of their constituent's position is a priority - including access, safety and network security, and
- Affordability, equity, transparency are also high priorities.

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.⁵

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

6.1 Stand-alone and Avoidable cost

Ergon Energy's Distribution Cost of Supply (DCOS) model that is 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 Ergon Energy's 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

⁵ NER, clause 6.18.5(c).

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 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; and

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

- 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
- 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. Ergon Energy has chosen to base its 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, and
- 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. This approach that has been adopted is consistent across the Ergon Energy and Ergon Energy.

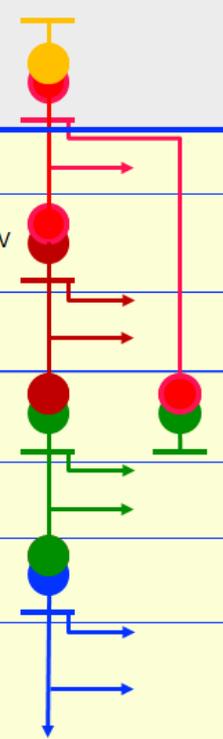
This approach that has been adopted is consistent across the Energex and Ergon Energy.

In the case of Ergon Energy 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 7 – Cost allocation for Stand-Alone and Avoidable network costs

Transmission (Powerlink)	Tariff Class		
	ICC	CAC	SAC
132,110kV	3.9%		
132,110kV/66,33kV	2.4%		
66,33kV	16.0%		
66,33kV/HV 132,110kV/HV	21.5%		
HV	20.6%		
HV/LV			16.1%
LV			19.5%



The schematic diagram shows a vertical stack of system levels. At the top is 'Transmission (Powerlink)' with a yellow circle. Below it is '132,110kV' with a red circle. The next level is '132,110kV/66,33kV' with a red circle. Below that is '66,33kV' with a red circle. The next level is '66,33kV/HV 132,110kV/HV' with two red circles. Below that is 'HV' with a green circle. The next level is 'HV/LV' with a blue circle. At the bottom is 'LV' with a blue circle. Red lines connect the top three levels, and green lines connect the next two levels, and blue lines connect the bottom two levels. Arrows indicate the flow of power between levels.

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 proportion of asset costs associated with each level of the network are also shown.

Ergon Energy has 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 Ergon Energy. The system connection level of the constituent tariffs that make up the three tariff classes is shown in the table below:

Table 10 – 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

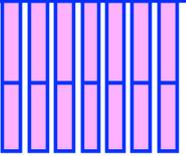
6.1.2 Lower bound test (Avoidable cost)

To determine the Avoidable costs of each tariff class, Ergon Energy estimated that cost 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 8 – Avoidable network cost calculation

Asset Group	Tariff Class		
	ICC	CAC	SAC
132,110kV		-5%	
132,110kV/66,33kV		-5%	
66,33kV		-5%	
66,33kV/HV 132,110kV/HV		-5%	
HV		-7%	
HV/LV			
LV			

The figure 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)

Ergon Energy’s 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 9 – 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 the figure 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

Ergon Energy has 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 the LRMC for Ergon Energy 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 regulator⁶⁷

⁶ Energy Networks Association (UK), *CDCM model user manual Model Version: CDCM model user manual Model Version: 103*, 28 August 2015.

⁷ Ofgem, *Electricity distribution structure of charges: the common distribution charging methodology at lower voltages*, Decision Document Ref: 140/09, 20 November 2009.

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, and
- The LRIC approach 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, Ergon Energy (and other DNSPs in the National Electricity Market) has 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 5 to 10-year regulatory forecasts 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, and
- 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.

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 the Ergon Energy 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 Ergon Energy. The model effectively replicates a scaled version of the existing network fully representative of its underlying characteristics.

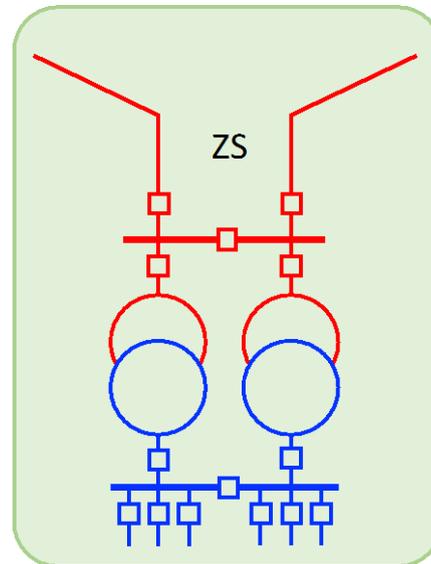
For example, at the 132 or 110kV zone substation level, a generic zone substation based on recently constructed projects is used. This is depicted below.

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 Ergon Energy, and
- 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), and
- HV/LV substation (kiosk and pole top)

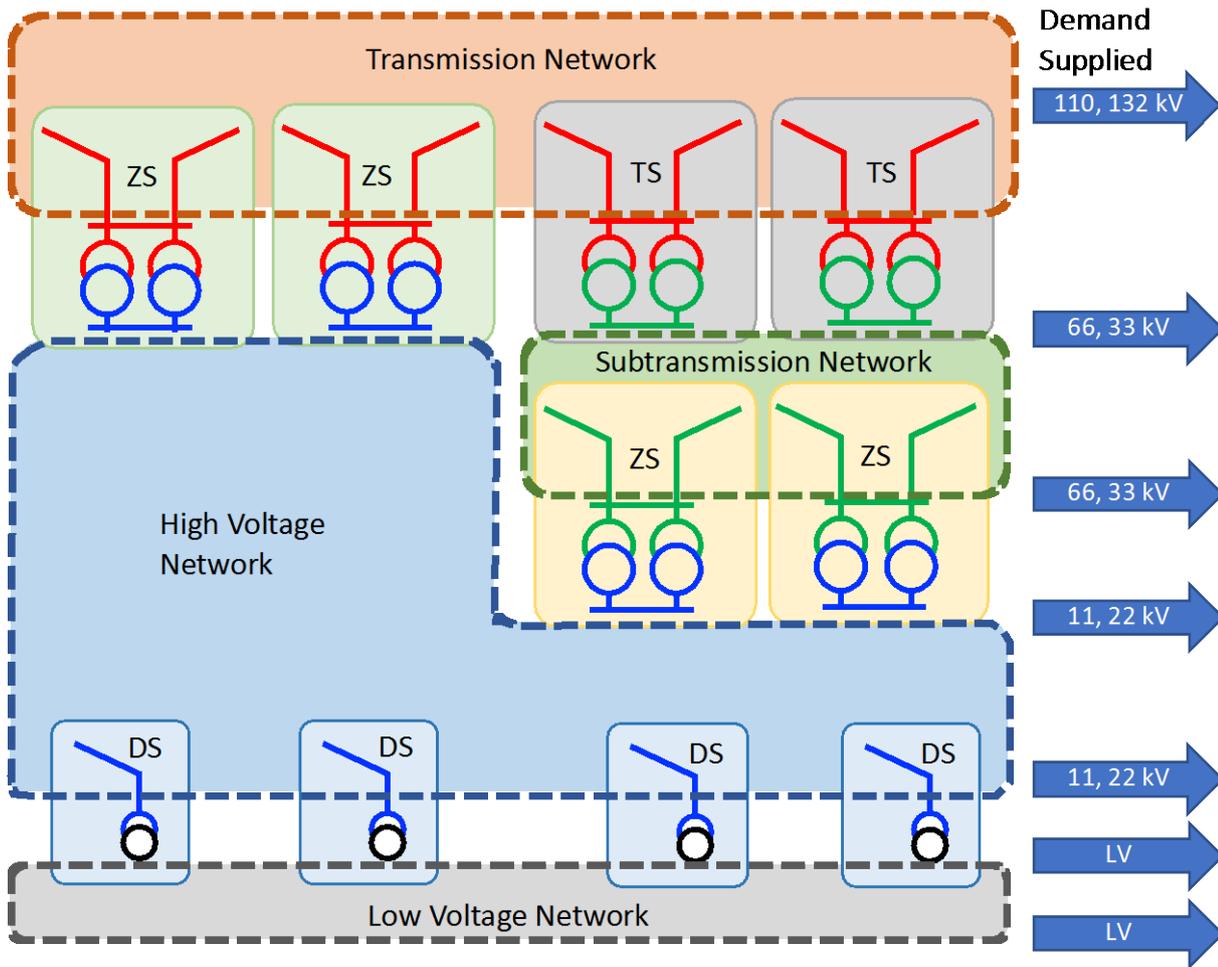


The LV network is also included in the model, on a similar basis (same length/capacity and overhead/underground ratios) as for the existing network. Each building block is assigned a capacity that can include emergency ratings and load transfers, reflecting Ergon Energy's normal practice in managing 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 Ergon Energy. 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, Ergon Energy uses 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 Ergon's West and Mount Isa pricing zones, which have relatively small demand.

Figure 10 - 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 (e.g. optimal equipment capacities) of Ergon Energy.

The demand connected at each voltage level matches the profile of Ergon Energy, 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 the Ergon Energy models.

6.2.4 Cost estimates

The Optimised Replacement Cost of the assets that form the building blocks provide 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 RAB. Land and easement values have 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 LRM 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 Ergon Energy to determine the LRM expressed in \$/kW/annum at each voltage level. Finally, the average power factor at each voltage level was used to determine the LRM 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 LRM rates into tariff quantities such as demand and peak energy rates. Rather, voltage level LRM 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 LRM 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 (e.g. \$/kVA or kW, \$/MW) subject to considerations of the individual customer impact.

6.2.7 Model Outcomes and Comparison with 2017-20 rates

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

Table 11 – Comparison of Proposed 2020-21 and current 2018-19 LRM values by voltage levels (Nominal)

Ergon Energy East and Mount Isa

Voltage Level	LRM 2020-21 \$/kVA/annum	LRM 2018-19 \$/kVA/annum
132/110/66kV/33kV	\$72	\$33
22/11kV	\$141	\$175
LV East	\$226	\$255
LV Mount Isa	\$103	
Notes:		
<ul style="list-style-type: none"> The figures are undiversified The figures are exclusive of GST. 		

Ergon Energy West

Voltage Level	LRM 2020-21 \$/kVA/annum	LRM 2018-19 \$/kVA/annum
132/110/66kV/33kV	\$107	\$93
22/11kV	\$360	\$437
LV	\$660	\$638
Notes:		
<ul style="list-style-type: none"> 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.

6.2.8 Future changes to the LRIC methodologies

Ergon Energy acknowledges that the LRIC methodology currently proposed in the 2020-25 TSS and described above will need to evolve in consideration of the growing impact of distributed energy resources on the network.⁸ In light of the changing technology environment, Ergon Energy intends to continue refining its methodology and calculations during 2019 for consideration in the Revised TSS submission. We welcome the AER consultation process to assist us in further investigating customer thoughts on the refinement of the LRIC methodology and calculations so as to best meet customer expectations in a fast changing environment.

In addition, Ergon Energy intends to consult during 2019 on the inclusion of an in-period variation mechanism that could enable new LRIC calculation methodologies to be adopted within the 2020-25 regulatory control period. Such a mechanism would ensure that changes in network cost drivers in the rapidly changing technology environment are reflected in a timely manner in the LRIC calculations that are used in setting network tariffs.

6.3 Managing customer impacts

Clause 6.18.5(h) of the NER requires that Ergon Energy 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, and
- The extent to which customers are able to mitigate the impact of changes in tariffs.

Ergon Energy understands 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 and details how customers who do choose to adopt demand tariffs can respond through usage behavioural change and technology adoption.

Ergon Energy considers customer impact based on comparisons to its 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 in Ergon Energy East, this tariff is Residential IBT and for our Small Business Customers, Business IBT.

It is important to note that Ergon Energy’s distribution network charge reductions, as set out in section 6.3 of the Ergon Energy 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 Ergon Energy’s distribution network charges.

⁸ It is noted that a different LRMC methodology is being proposed for the purposes of the capital contribution in the Regulatory Proposal. In reviewing the LRMC approach noted here Ergon Energy will review and harmonise the LRMC value for the purpose of the Revised TSS

6.3.1 Modelling Customer Impact

Ergon Energy has 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 Ergon Energy’s Residential Customer Class, approximately 1,350 of a pool of 0.495 million 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, but 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.

It must be noted that this customer impact modelling is limited to those tariffs included in our TSS. As the AER reviews our submission and further customer consultation is undertaken, the structure of these tariffs may change. We will update all modelling for our Revised TSS and provide the AER with updated modelling if and as requested throughout the consultation period.

6.3.2 Impact of tariff reform on residential customers

6.3.2.1 No Change to Customer Tariff

Ergon Energy is committed to achieving a real reduction⁹ in distribution network charges for residential customers on the relevant legacy network tariffs from 2019-20 to 2020-21. Should customers choose to remain on the legacy IBT Residential tariff without any change in network usage, the indicative reduction in the distribution network component of those customers’ bills is set out in the table below:

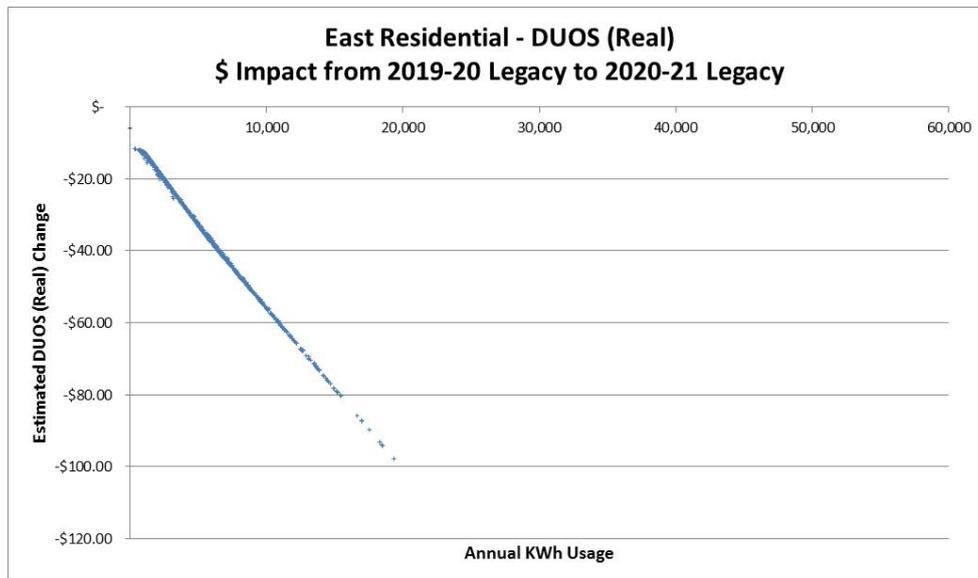
Table 12 - East IBT Residential 2020-21 DUOS Tariff Impact (Real)

Customer Size	Percentage Impact	Dollar Impact
Small (2,917 kWh)	-3.7%	-\$21.74
Average (4,865 kWh)	-4.5% ¹⁰	-\$31.50
Large (7,457 kWh)	-4.7%	-\$42.64

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

⁹ 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

¹⁰ Under the Uniform Tariff Policy, the Queensland Government will subsidise any difference through Community Service Obligation (CSO) payments to support regional Queenslanders, ensuring they pay similar prices for their electricity as customers in South East Queensland.



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

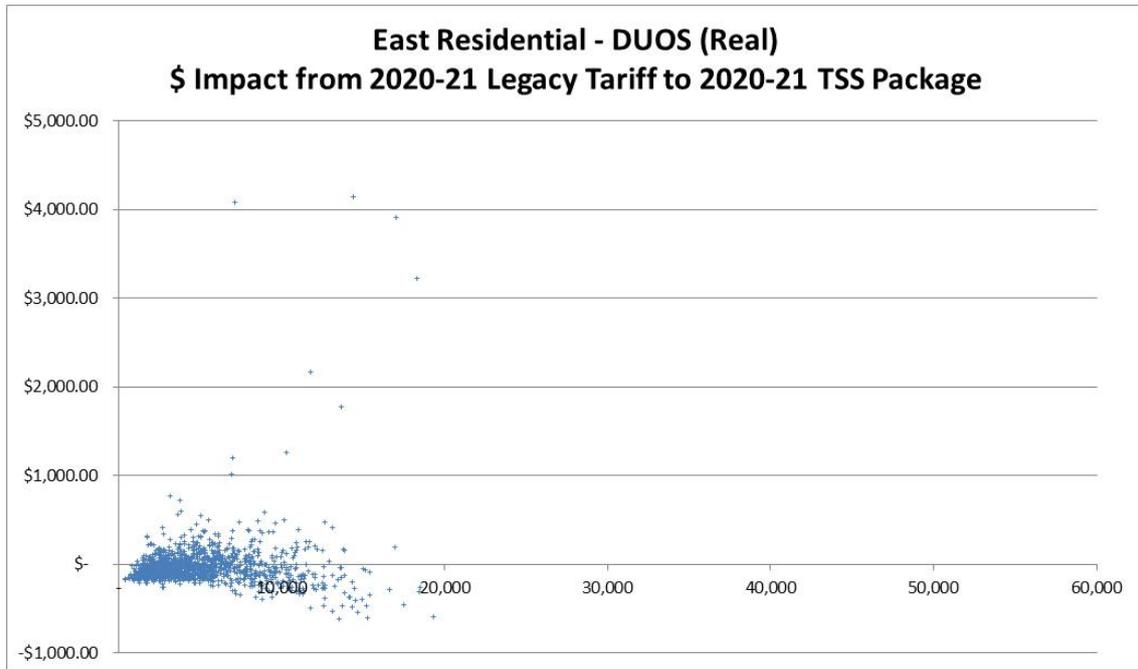
6.3.2.1 Residential customers Migrating to Lifestyle Package

Residential customers who opt-in to the Lifestyle Package in 2020-21 will have the opportunity to realise even greater reductions in the distribution network component of their bill than customers who remain on their legacy tariffs. Many customers will see savings in the distribution network component of their bill without needing to change their electricity usage, and others may be able to realise even larger savings by moving some of their usage outside the SPW. The indicative reductions for customers who do not change their usage on the Lifestyle Package are set out in the table below:

Table 13 – East IBT Residential moving to Lifestyle Package 2020-21 DUOS Impact (Real)

Customer Size	Percentage Impact	Dollar Impact
Small (2,917 kWh)	-20.1%	-\$117.36
Average (4,865 kWh)	-8.9%	-\$62.96
Large (7,457 kWh)	-8.5%	-\$76.68

However some customers may need to review when they use the network in order to realise savings in the distribution network component of their bill. As demonstrated in the following chart, customers of both small and large annual usage volumes may enjoy savings if they can spread their load outside the SPW:



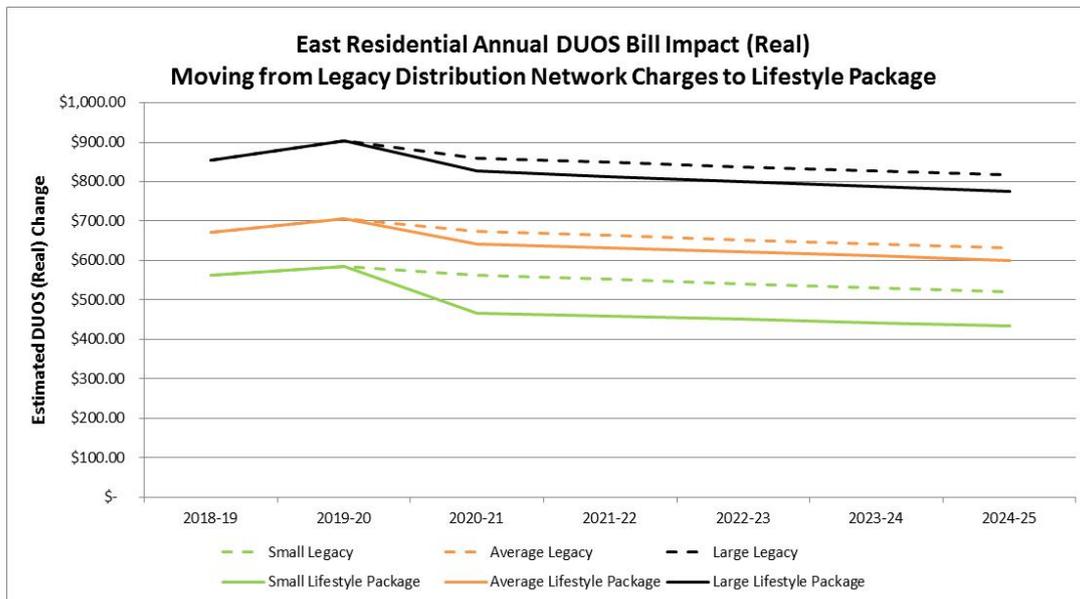
Note: one data point on this chart may represent one or many customers as noted in 6.3.1.

For those customers unable to shift usage outside the SPW, they may choose to remain on our legacy tariffs.

6.3.2.2 Indicative Charge Projections

Our representative customers will receive a real reduction¹¹ in the distribution network component of their bill from 2019-20 to 2020-21 and customers on the Lifestyle Package will receive ongoing real reductions¹¹ throughout the regulatory control period, as shown in the chart below. We anticipate approximately 70.0% of our residential customers will achieve a real reduction¹¹ in the distribution network component of their bill in 2020-21. However as noted above, some customers may need to make changes to their network usage to realise savings.

¹¹ 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



6.3.3 Impact of tariff reform on small business customers

6.3.3.1 No Change to Customer Tariff

Ergon Energy is committed to achieving a real reduction¹² in distribution network charges for small business customers on the relevant legacy network tariffs from 2019-20 to 2020-21. Should customers choose to remain on the legacy IBT Business tariff without any change in network usage, the indicative reduction in the distribution network component of those customers' bills is set out in the table:

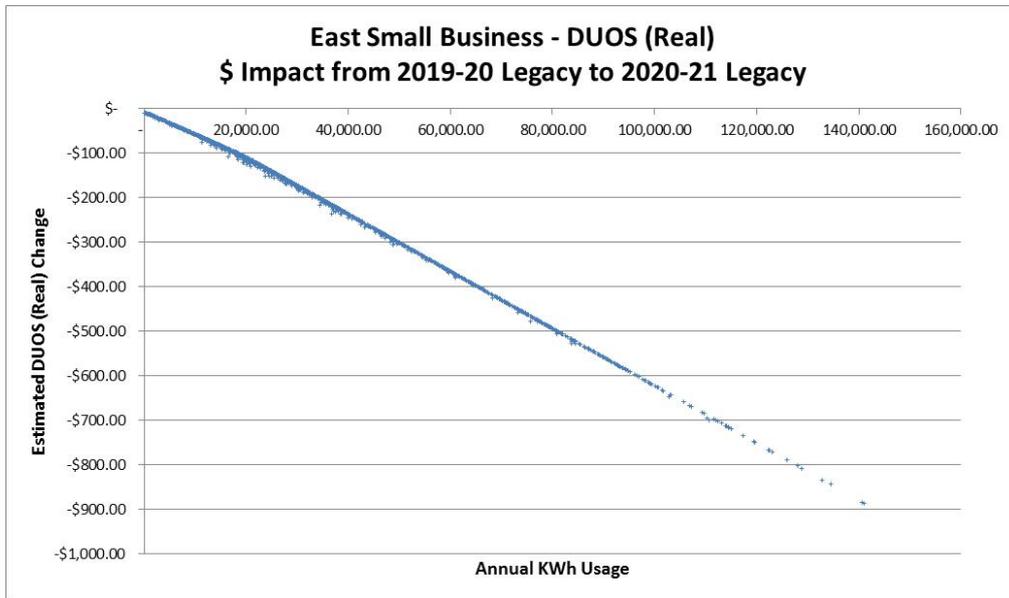
Table 14 - East IBT Business 2020-21 DUOS Charge Impact (Real)

Customer Size	Percentage Impact	Dollar Impact
Small (1,466 kWh)	-2.8%	-\$14.50
Average (7,457 kWh)	-4.5% ¹³	-\$44.92
Large (19,250 kWh)	-5.3%	-\$105.26

¹² 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

¹³ Under the Uniform Tariff Policy, the Queensland Government will subsidise any difference through Community Service Obligation (CSO) payments to support regional Queenslanders, ensuring they pay similar prices for their electricity as customers in South East Queensland.

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.

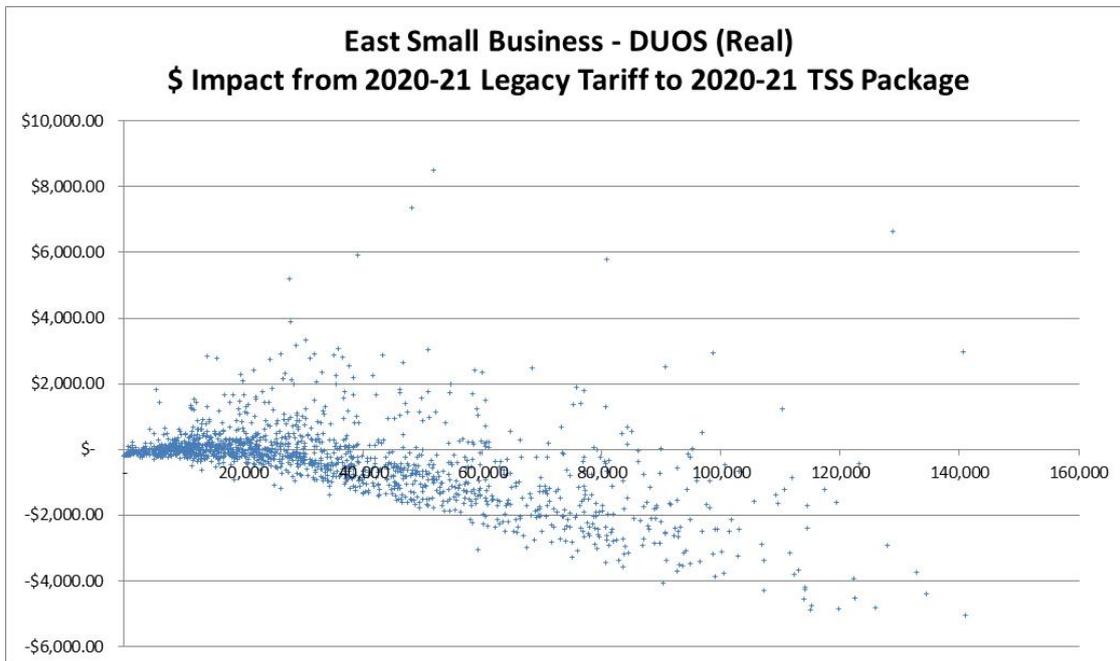
6.3.3.2 Small Business Customers Migrating to Small Business Package

Small business customers who opt-in to the Small Business Package in 2020-21 will have the opportunity to realise even greater reductions in the distribution network component of their bill than customers who remain on their legacy tariffs. Many customers will see savings in the distribution network component of their bill without needing to change their electricity usage, and others may be able to realise even larger savings by moving some of their usage outside the SPW. The indicative reductions for customers who do not change their usage on the Small Business Package are set out in the table below:

Table 15 – East IBT Business moving to Small Business Package 2020-21 DUOS Impact (Real)

Customer Size	Percentage Impact	Dollar Impact
Small (1,466 kWh)	-23.7%	-\$123.15
Average (7,457 kWh)	-7.8%	-\$78.46
Large (19,250 kWh)	+0.7%	+\$14.41

However some customers may need to review when they use the network in order to realise savings in the distribution network component of their bill. As demonstrated in the following chart, customers of both small and large annual usage volumes may enjoy savings if they can spread their load outside the SPW:



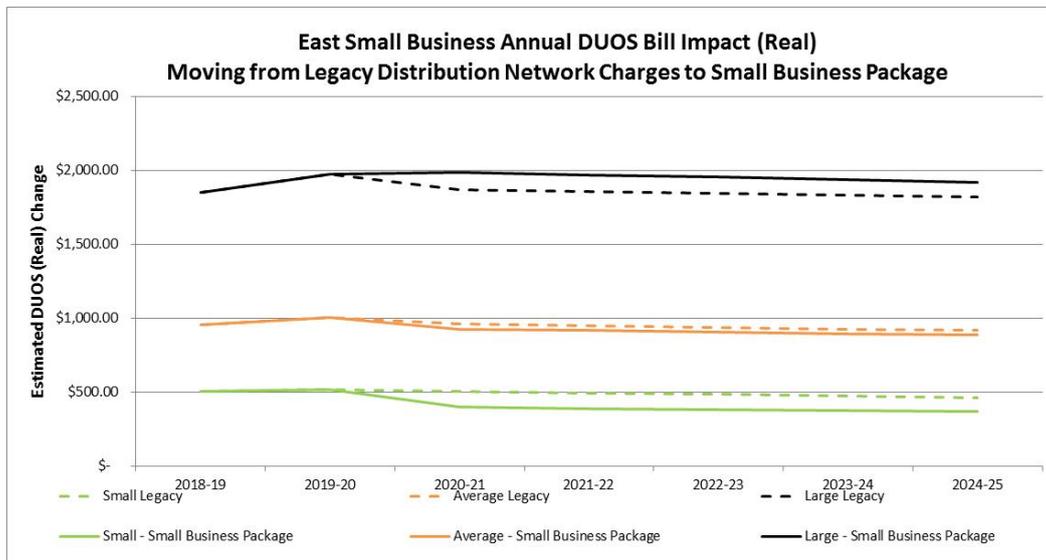
Note: one data point on this chart may represent one or many customers as noted in 6.3.1.

For those customers unable to shift usage outside the SPW, they may choose to remain on our legacy tariffs.

6.3.3.3 Indicative Charge Projections

Our representative customers will receive a real reduction¹⁴ in the distribution network component of their bill from 2019-20 to 2020-21 and customers on the Small Business Package will receive ongoing real reductions¹⁴ throughout the regulatory control period, as shown in the chart below. We anticipate approximately 67.0% of our residential customers will achieve a real reduction¹⁴ in the distribution network component of their bill in 2020-21. However as noted above, some customers may need to make changes to their network usage to realise savings.

¹⁴ 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



6.4 Stakeholder Engagement

Please refer to *Tariff Structure Statement 2020-25 Engagement Summary* for a summary of the outcomes for 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 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. Ergon Energy’s ACS include:

- Connection services (i.e. 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), and
- 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 Ergon Energy’s 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 16 - ACS tariff classes

Tariff Class	Activity
Connection services	<p>Pre-connection services</p> <p>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.</p> <p>Generally relates to services which require a customised or site-specific response and/or are available contestably.</p> <p>Unless otherwise specified, services or activities undertaken under this service group relate to both small and large customers and real estate development connections.</p>
	<p>Connection services</p> <p>Connection services include the design, construction, commissioning and energisation of connection assets for large customers and for real estate developments.</p> <p>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. Ergon Energy considers that generators larger than 30kVA but smaller than 1MW should be treated as EGs for the purpose of removing network constraints.</p> <p>Include temporary connections for short term supply (e.g. blood bank vans, school fetes).</p>
	<p>Post-connection services</p> <p>Post-connection services are those services initiated by a customer which are specific to an existing connection point.</p>

Tariff Class	Activity
	<p>Accreditation services</p> <p>Accreditation of alternative service providers and approval of their designs, works and materials.</p>
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	<p>Type 6 Metering</p> <p>Metering services encompass the metering installation, provision, maintenance, reading and data services of Type 6 metering.</p> <p>Auxiliary Metering Services</p> <p>Includes work initiated by a customer which is specific to a metering point.</p>
Public lighting	Public lighting services relate to the provision, construction and maintenance of public lighting assets owned by Ergon Energy (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 list 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 17 - 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	<p>Application fee for a Negotiated connection offer.</p> <p>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.</p>	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	<p>Provision of connection advice, assessment and data requests for site-specific connections (during the connection enquiry and/or connection application stage). For example:</p> <ul style="list-style-type: none"> • 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, and 	Quoted

Category	Service Description	Charging arrangements
	<ul style="list-style-type: none"> Additional or more detailed specification and design options. 	
Preparation of preliminary designs and planning reports	<p>Preparation of preliminary planning and design reports for major customer connections, including project scopes and estimates.</p> <p>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.</p>	Quoted
	<p>Provision of advice, design and specification on request to an applicant considering a build-own-operate asset ownership option for connection assets.</p>	Quoted
	<p>Detailed enquiry response fee</p> <p>Costs associated with preparing a detailed enquiry response pursuant to Chapter 5 of the NER.</p> <p>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.</p>	Quoted
Tender process	<p>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.</p>	Quoted
Connection services		
	<p>Customer requested temporary connection (short term) and the recovery of the temporary builders supply. Excludes work on metering equipment.</p>	Fee based
Post Connection Services		
Supply Abolishment (simple)	<p>Retailer requests Ergon Energy 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.</p>	Fee based
Supply Enhancement	<p>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.</p>	Fee based
Point of attachment relocation	<p>Customer requests their existing overhead service to be replaced or relocated, e.g.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).</p>	Fee based
Re-arrange connection assets at customer's request	<p>Rearrange connection assets at customer's request - simple (upgrade from overhead to underground where main connection point is in existence).</p> <p>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.</p>	Fee based
Temporary disconnections and reconnections (which may involve a line drop) - LV	<p>Temporary de-energisation and re-energisation of supply to allow customer or contractor to work close - the service may be physically dismantled or disconnected (e.g. overhead service dropped). This service includes switching if required.</p> <p>Temporary LV service Drop and re-erect (dismantling).</p>	Fee based

Category	Service Description	Charging arrangements
Faults/Emergency response	Attending loss of Supply - customer fault.	Fee based
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 (i.e. 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

Ergon Energy's 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 18 - 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. 1 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. 2 crews.	Fee based
Customer requests provision of electricity network data requiring customised investigation, analysis or technical input (e.g. 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, e.g. 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	Quoted

Service Group	Charging arrangements
<p>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:</p> <ul style="list-style-type: none"> a. restoration of supply due to customer action b. re-test at customer's installation (i.e. 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) c. safety observer d. tree trimming e. switching f. cable bundling, and g. 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, e.g. 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 (e.g. 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.¹⁵ 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, Ergon Energy is no longer responsible for providing metering installations as they are subject to contestability. Ergon Energy is 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 Ergon Energy. However, in the Power of Choice exempt areas (Mount Isa-Cloncurry and Isolated supply networks) Ergon Energy remains 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.

¹⁵ Type 5 meters are not permitted in Queensland.

Table 19 - Classification of Ergon Energy metering services

Metering Type	Description	Charging arrangements
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

Ergon Energy’s 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 the Ergon Energy 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. Ergon Energy is 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, Ergon Energy has 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 the table below:

Table 20 - 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	<p>Conventional and LED lights:</p> <p>Non-contributed (EEO):</p> <ul style="list-style-type: none"> NPL1 Major: high watt NPL1 Minor: low watt <p>Contributed (GOO):</p> <ul style="list-style-type: none"> NPL2 Major (high watt) NPL2 Minor (low watt) <p>LED only lights:</p> <p>Contributed (GOO)</p> <ul style="list-style-type: none"> NPL4 Major (high watt) NPL4 Minor (low watt) 	Limited Building Block	Public light daily fixed fee
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, and
- 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 Ergon Energy. In this circumstance, the associated pole and cabling remain legacy and non-contributed assets owned by Ergon Energy. Ergon Energy will operate and maintain the entire public lighting asset.

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

Ergon Energy's 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, and
- 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 Ergon Energy's 2020-25 Regulatory Proposal for further details on the revenue for public lighting services.

Separate calculation of the NPL4 tariff:

In line with customer expectations, Ergon Energy is 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 Ergon Energy has 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 Ergon Energy. 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 (i.e. the pole, bracket, cables etc). The NPL4 tariff can therefore not be set higher than the NPL1 rate, and
- 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.

Overarching calculation methodology for NPL1 and NPL2

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 21 - 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, such that 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, and
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 Ergon Energy. 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

Ergon Energy proposes 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.

Ergon Energy proposes 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), and
- 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.

Appendix A – Additional Tariffs Options under Development

1. Purpose of this Appendix

This appendix sets out a number of tariff options, in addition to the Package tariffs, that Ergon Energy is still developing at the time of submitting the TSS in January 2019, following extensive customer and stakeholder consultation in 2018. The timing of the development of these network tariff options is also reflective of the highly dynamic and evolving environment in which distribution network businesses are now operating. This is particularly true given the pace of change in the way customers are using our distribution network, and that the distribution networks now services different and distinct customer expectations during daytime and night time as the usage of DER continues to proliferate.

As such, the potential network tariff options set out in this appendix have not yet been fully developed and time has not allowed for these tariff structure options to be consulted on or developed to a stage consistent with inclusion in a compliant TSS.

Ergon Energy is happy to continue to work with the AER and stakeholders on these options, but note the opportunity for the proposed network tariff options to become part of the next phase of the discussion of the optimal suite of network tariffs within the TSS is dependent on the scope of TSS review and consultation sought by the AER. Ergon Energy is keen to ensure the network tariff options being developed adequately respond to customer needs whilst ensuring a timely transition to future state network tariffs beyond 2025.

The remainder of this appendix is structured as follows:

- Section 2 considers a set of additional intermediate network tariff options, that facilitate the timely transition of SAC customers from legacy network tariffs to future cost reflective capacity based tariffs as contemplated in our network tariff reform journey
- Section 3 considers a set of proposed dynamic response tariffs for business customers that incorporate load control to offer customers additional choice and control options that suit their particular business needs

2. Proposed Intermediate Network Tariff Options

Throughout our TSS engagement sessions prior to January 2019, customer feedback on the new cost reflective tariffs and the Lifestyle Package for our 2020-25 TSS was generally positive. However, as may be anticipated with any new tariff structures, some reservations were noted, particularly from our residential and small business customers less familiar with demand based tariffs. A summary of feedback received to date on the proposed new cost reflective tariffs is included in the table below.

Table 1: Summary of customer feedback on cost reflective ‘Package’ tariffs

Attractions	Reservations
<ul style="list-style-type: none"> • Ability to smooth network seasonality by selecting an appropriate tariff option • Enhances access to choice and control (subject to retailer role & response) • Is adaptable to new information and changing technologies, demand patterns and evolving network usage • Provides an opportunity for customers to transition to demand/capacity tariffs in future regulatory control periods • Positive step toward dealing with cross subsidies • Rewards higher load factor customers • A step towards cost reflective and more sustainable use of the network • Customers are rewarded for ‘doing the right thing’. 	<ul style="list-style-type: none"> • More intricate than non-cost reflective tariffs • Band selection is a new activity • Some customers will be left behind, particularly those who cannot afford access to a digital meter • Structure may result in unexpected bill variability as a result of a lack of understanding of the tariff • Customers need flexibility and visibility to avoid using more than the network access allowance • Unclear on how to move up and down between network access allowance bands • Uncertainty around how retailers would present a retail price structure on top of the Lifestyle Package • Optimal definition of the Summer Peak Window (SPW) • Ensuring technology, services, education campaigns and tariff benefits are equally accessible to all customer groups

Many of the reservations in Table 1 are not unique to the Lifestyle Package structure and are likely to apply to any significant tariff structure changes proposed for smaller customers as fundamental tariff reform is progressed.

During stakeholder engagement in late 2018, responses received were seeking further consideration of issues, such as:

- The need to develop a default tariff that is straightforward to assign, more cost reflective than the legacy network tariffs and starts the transition journey, particularly for basic meter customers, towards more cost reflective tariff structures
- The future relevance of LRMC-based pricing of network peak usage in periods of low demand growth
- The suitability of calculating LRMC based on demand growth being met through traditional network capacity augmentation solutions
- Optimal dimensioning of the SPW for the Lifestyle, Small Business and Business Packages
- The challenges for retailers/customers in the initial selection of the optimal network access allowance band of the Lifestyle and Small Business Package
- Facilitation of the transition of customers onto the Lifestyle Package and encouragement of digital meter adoption

- Accommodating uncertainty around the pace and direction of change in the 2020-25 regulatory control period, the level of DER adoption, how DER is utilised and the optimal tariff signals to be projecting
- The drivers of network investment during and beyond the 2020-25 regulatory control period
- Managing tariff induced network peak risks (i.e. shifting of the time and magnitude of network usage peaks) and optimising the peak window, and
- Lifestyle and Small Business Package tariff only being an option for customers with a digital meter which limits the addressable market for the tariff.

Following our consultations in 2018, and in response to customer and stakeholder feedback, we are considering additional intermediate network tariff options for our SAC customers to assist their transition to cost reflective capacity based tariffs. At the time of submitting the TSS, these intermediate network tariff options have not yet been consulted upon and are currently conceptual in nature, reflecting their emergence in the latter stages of the TSS consultation process. Two additional intermediate network tariff options have undergone preliminary investigation, with the first being the Intermediate Capacity tariff option, and the second being the Intermediate Tiered tariff option. We are proposing to include demand and energy versions of the proposed new tariffs for SAC Small business and residential customers in recognition of the different capabilities of basic metering and digital metering. For SAC Large only the digital meter demand option is being explored.

We welcome the AER consultation process to assist us in further investigating customer thoughts on the development of intermediate network tariff options that best meet customer expectations in a fast changing environment. To facilitate this process, we have provided preliminary details on the proposed structures of these intermediate network tariff options in the following sections.

2.1. Intermediate network tariff options

2.1.1. Intermediate Capacity tariff option

Capacity tariffs are based on the premise that peak demand driving upstream network investment will become a lesser issue as customers continue to invest in ubiquitous levels of distributed energy resources and both customers and the network businesses access affordable and smarter technology. Under this scenario there would be a bias towards the network providing adequate capacity rather than facing upstream network peak driven constraints.

However, in considering a transition under this scenario usage at the low voltage end of the network requires careful consideration. For example, for the residential segment there is potential for the network to be facing a night-time constraint. In addition in day time periods the shift of the traditional LV network from a passive unidirectional supply element to an active network creates new challenges and different costs for the network.

The proposed Intermediate Capacity tariff would potentially recognise the difference in customer utilisation during the day or night with different energy charging rates to be applied between 6am to 6pm (day time) and between 6pm to 6am (night time). Initially these energy charging rates could be set to be the same level during the 2020-25 regulatory control period, with a view to progressively introducing different rates established once further information on the network cost differentials become available.

For discussion, stakeholders may consider the following capacity tariff structure.

Table 2: Structure of proposed Intermediate Capacity tariff

Charging parameters	Basic Meter			Digital Meter		
	Fixed (\$/day)	Capacity - Anytime (inferred) ²	Volume (\$/kWh)	Fixed (\$/day)	Capacity - Anytime (\$/kW/Month)	Volume (\$/kWh) ³
Rate to be determined ¹	Rate to be determined	Rate to be determined	Rate to be determined	Rate to be determined	Separate daytime and night time rates (may be set equal initially).	
						Rates to be determined

Note 1: Ergon Energy has not been able to develop indicative rates for these tariffs prior to submitting the TSS but will provide them to the AER as part of its stakeholder engagement process post 31 January 2019.

Note 2: The inferred capacity charge for basic meter customers would form part of either the fixed charge or the volume charge. Further analysis and modelling is being undertaken to determine which charging parameter would best reflect the inferred capacity

Note 3: The tariff structure will accommodate two volumetric charges to allow for separate daytime and night time charges. This is in recognition of the different network utilisation and costs associated with accessing network services at these times. During the 2020-25 regulatory control period, these rates are intended to initially be set to be the same as we perform further analysis to better understand the differences in costs associated with the different network utilisation characteristics during the daytime and night time.

It is envisaged that, for customers with a digital meter, the capacity charge would be based on the customer's maximum ½ hour anytime kW demand peak in the monthly billing period. For customers with basic meters, an average capacity would be inferred for all the customers on the tariff which would then be recovered through either the fixed or volume component of the capacity tariff. These charging arrangements could be developed subject to AER consultation throughout 2019.

This time of use charge would only apply to customers with a digital meter as it is not possible to differentiate daytime and night time usage for customers with basic meters. Customers could, however, be incentivised to upgrade to a digital meter to take advantage of the day and night time charge differential.

It is proposed that the LRMC signal would be included in the capacity charging parameter. For customers with a digital meter this would be recovered based on the maximum anytime demand recorded. This recognises the customer's impact on the network costs in terms of overall capacity requirements.

This tariff reflects a future where new network capacity investment is not related to demand within an identified peak demand window.

2.1.2. Intermediate Tiered tariff option

The Intermediate Tiered tariff option has an energy and demand version depending on the customer's metering arrangements. It is envisaged as a 'fixed plus energy' structure for customers with either a basic meter or digital meter.

The Intermediate Tiered tariff also differs from the Intermediate Capacity tariff in that it measures demand with reference to a non-seasonal peak window and within the tariff has tiers which allow for the LRMC component of the tariff to vary within each tier.

Tiers present the opportunity for more granularity to be achieved. Each tier can have a peak demand building block specific to the tier. The tiered structure also allows for a more consistent distribution of customer impacts and some limited incentive for customer response to the different charges in the tiers.

The Intermediate Tiered tariff can also incentivise digital meter tariff adoption, provide a more nuanced linkage between customer consumption and the LRMC component of the tariff and manage risk associated with customers with very low or high levels of annual consumption.

Each tier would contain its own daily fixed charge and volume charge, with the volumetric charge expected to be the same across all of the tiers. For discussion, stakeholders may consider the following tiered tariff structure:

Table 3: Structure of proposed Intermediate Tiered tariff

Tier	Energy for customers with basic meters (kWh p/a) ¹	Demand for customers with digital meters (kW) ^{2,3}	Fixed Charge (\$/day) ²	Volume Charge (\$/kWh) ²
1	N/A	0 – 1.5	To be determined	To be determined
2	0 – 1,500	1.5 - 3.0	To be determined	To be determined
3	1,500 – 3,000	3.0 - 4.2	To be determined	To be determined
4	3,000 – 5,000	4.2 - 5.3	To be determined	To be determined
5	5,000 – 7,500	5.3 - 6.6	To be determined	To be determined
6	7,500 – 12,000	6.6 - 8.6	To be determined	To be determined
7	12,000 – 15,000	8.6 - 10.8	To be determined	To be determined
8	15,000 +	10.8 +	To be determined	To be determined

Note 1: The energy and demand thresholds for the tiers are illustrative only.

Note 2: Indicative rates have not been provided in this document as tariff has not been modelled at the time of submission this TSS. These rates will be provided to the AER to support its stakeholder engagement process.

Note 3: For digital meter customers it is contemplated that the demand tier would be based on the average demand of the three highest days in each month.

This tariff option has some alignment with the Lifestyle Package in terms of the underlying building block structure and carries through both the referencing of the peak window demand (on a non-seasonal basis) and using LRMC to determine the incremental cost associated with each tier's fixed component of the tariff.

2.2. Rationale for the additional Intermediate Network Tariff Options

The structures of these intermediate network tariff options are a step towards addressing stakeholder inputs, particularly from the agricultural sector, that highlighted the low level of capacity augmentation being forecast out to 2025 while also querying the dimensions of the SPW and the appropriateness of how the LRMC was being applied.

Both intermediate network tariff options will provide a mechanism whereby once a customer has access to a digital meter they are able to move to the demand based version of the relevant tariff. In providing similar tariffs and tariff structures for customers with digital and basic meters, it is expected that the impact of change on residential and small business customers transitioning from an energy to a demand tariff can be mitigated. It is also expected that once on the demand version of the intermediate tiered tariff, adopting a future capacity based tariff becomes another incremental step that can be made based on improved customer familiarity with digital meters and the concept of demand and bands.

Importantly the intermediate network tariff options do not require the retailer/customer to nominate a tier as billing is simply based on the customer's metered energy or demand in the billing period.

Compliance of the Intermediate Capacity tariff and Intermediate Tiered tariff options with the pricing principles is demonstrated in the table below.

Table 4: Intermediate network tariff options' compliance with the pricing principles

Pricing Principle	Dimension	Intermediate Capacity Tariff	Intermediate Tiered Tariff
Tariffs must be based on LRMC	LRMC recovery (demand)	LRMC is included in the capacity charge parameter (for digital meters).	Recovered in a peak demand tariff rate parameter specific to each tier.
	LRMC recovery (energy)	LRMC is included in the inferred capacity charge parameter (for basic meters).	Recovered in a peak demand tariff rate parameter specific to each tier.
Recover the efficient network costs that minimises distortions to tariff signal	Time of use signals	Day – Night differential only, dependent on customer's metering arrangements. However rates for day and night will be set to be the same with a view to having different rates once further information is available.	Sets tier rates in a way that links with times of higher use of the network. Seasonality removed to support business rules, billing process and customer move in/move out equity.
		Nature of customer usage response to the tariff signal	Customer incentivised to independently minimise each monthly anytime maximum ½ hour demand. Underlying tariff incorporates a moderate incentive to move energy/demand out of the current distribution peak demand exposure period.
	Impact on network utilisation	No differentiation between times of high and low use of the network for customers with basic meters.	Underlying tariff structure supports utilisation improvement by linking demand charge component to LRMC and the times of daily system peak.
	Movement towards cost	Consistent with cost drivers in a future where network	Broadly consistent with the underlying the Lifestyle

Pricing Principle	Dimension	Intermediate Capacity Tariff	Intermediate Tiered Tariff
	reflective tariffs	investment is not exclusively driven by seasonal customer driven demand and maintaining power quality and stability in an active low voltage network emerges as a priority.	Package tariff structure principles, while taking out the seasonality component. The structure also aligns with transitioning down the capacity pricing path.
Simplicity	Customer Understanding	Little change, noting network tariffs effectively transparent to the customer. Energy tariff is a structure which retailers and customers are familiar with	At the customer level, the variation in network cost under the tiered tariff is more consistent. A less variable impact is expected to be easier for the retailer to manage. No decisions necessary by the customer or retailer to manage tiers.
	Customer Experience	Simple. Will need to determine strategies to optimise any day / night energy rate variations and monthly maximum ½ hour anytime maximum demand	Little change, noting network tariffs effectively transparent to the customer.
Customer impact	Vulnerable and Hardship Customers	Reversion option to the legacy fixed plus volume tariff where worse off on new tariffs Lifestyle Package remains an option for these customers. Customer impact issues & management required based on consumption	Reversion option to the legacy fixed plus volume tariff where worse off on new tariffs Lifestyle Package remains an option for these customers. Supports option of digital meter, tiered demand tariff (or the Lifestyle Package) and TED1 to support vulnerable customers.
	Customer Assignment	Potentially could become default tariff post 1 July 2020. Opt in to Lifestyle Package. Existing NMI access to the legacy tariff.	Potentially could become default tariff post 1 July 2020. Opt in to Lifestyle Package. Existing NMI access to the legacy tariff.
	Future flexibility	Establishes a pathway to a capacity tariff	Potential to evolve to either a capacity tariff or a Lifestyle Package type structure depending on how market develops out to 2025.
	Impact on digital meter adoption		Systemic driver mechanism linked to the setting of the tier bands is feasible.

Pricing Principle	Dimension	Intermediate Capacity Tariff	Intermediate Tiered Tariff
	Granularity	Has a single pivot point, if recover capacity through fixed then have single fixed component that applies for consumption from 0 to 100,000kWh.	Supports progressive allocation of demand costs in line with the characteristics of each tier, i.e. more cost reflective.
	Ability for customer to respond in some way to the tariff	Limited for the energy version of the tariff	Limited. Digital meter version of the tariff starts to present response pathways.

3. Proposed Dynamic Response Network Tariff Options

As part of the TSS consultation process during 2019, dynamic response tariff options (similar to controlled load) based on a discount on the Small Business and Business packages have emerged as potential new network tariffs for the 2020-25 regulatory control period. These tariffs would respond to rural segment customer and network opportunities (with irrigation and pumping load an initial focus), but would not be exclusive to a particular end-use.

The dynamic response tariff options would support distributor controlled and owned demand response products where an agreement with the customer exists to fully control load whenever the distributor wants within the tariff terms and conditions. Two levels of dynamic response products, benefit and associated tariffs are being considered.

The first provides the distributor with enough supply interruption capacity to ensure the load under control is not presenting to the distribution network at local distribution system peak times (as determined and managed dynamically by the network). It is envisaged the tariff would apply as a primary tariff to a separately metered circuit that may be applied as determined by Ergon Energy.

The second offer extends the intended value to the network to include the ability to control load so that it is presenting to the network during times of low network demand (e.g. times of high distributed customer solar output) by ensuring controlled load is off leading into the local network solar trough. To realise the required functionality, the customer agreement would be different and the types of customer and end-uses that may be suitable would also be different. A different customer value proposition is proposed to reflect the different imposition on the customer and value to the network.

Access to both tariffs would be predicated on the customer agreeing to the network having the control to ensure the load does not present at network peak. In return for this right the LRMC recovery component of the tariff can be discounted based on the peak control being vested in the distributor. This tariff would be offered as a primary tariff with a fixed plus volume structure.

Access to the tariffs would be based on the customer having a load control agreement which in turn would be predicated on the network being able to activate the control with the customer, and the location having benefit to the network.

The structure of the proposed demand response tariffs are as follows:

- Fixed charge (\$/day), and
- Usage charge (\$/kWh)

These tariffs are proposed on the basis that Ergon Energy has the right and ability to be able to ensure the load will not present to the network during local network peak times. On the basis of this control, these tariffs do not attract full recovery of LRMC. However, they would attract residual revenue recovery through both the fixed and usage charges.

Compliance of the dynamic response tariff options with the pricing principles is demonstrated in the table below.

Table 5: Dynamic response tariffs' compliance with the pricing principles

Pricing Principle	Dimension	Dynamic Response Tariffs
Tariffs must be based on LRMC	LRMC recovery (demand)	The tariff is based on the customers load being able to be controlled so as not to impact on system demand. LRMC is therefore discounted to reflect that the load will not be contributing to system augmentation.
	LRMC signal strength	LRMC reduced in accordance with reduction of contribution to peak demand

Pricing Principle	Dimension	Dynamic Response Tariffs
Recover the efficient network costs that minimises distortions to tariff signal	Residual cost recovery	Residual cost recovery through fixed and variable charges in alignment with the lifestyle package structure with additional consideration of specific load control costs and willingness to pay.
	Nature of customer usage response to the tariff signal	Customer accepts an agreed level of direct distributor load control at distributor discretion in return for the network tariff reduction
	Impact on network utilisation	Ensures the controlled load is not contributing to network peak demand so the energy being used contributes to network utilisation without increasing demand.
	Movement towards cost reflective tariffs	Tariff is reflective of the costs of a load which is not contributing to peak Incentivises use of the network during the solar trough to minimise cost of maintaining power quality and stability.
Simplicity	Customer Complexity	Tariff will be part of a broader load control arrangement offer
	Customer Experience	Supports additional product/service option development for customers to consider.
Customer impact	Vulnerable and Hardship Customers	Presents an option for lower network charges for loads that the customer is prepared to agree to have controlled within agreed parameters.
	Customer Assignment	Tariff is optional, no customer assignment is anticipated.
	Future flexibility	Tariff flexibility is limited
	Impact on digital meter adoption	Tariff is not expected to directly drive digital meter adoption
	Granularity	Distributor control allows load control to be aligned specifically with times of network need in real time. This is more granular than the lifestyle package that the dynamic response tariff is based on where the SPW is set in advance.
	Ability for customer to respond in some way to the tariff	Customer response ability is through choosing to offer distributor control of the load within agreed parameters. Tariff availability expected to be directly linked to where realisable network benefits from the load control are achievable and would be part of a broader load control package and agreement.

Appendix B – 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
LRMC	Some customers 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.	<p>To address customer concern about the transition to demand, we have developed two new innovative products for mass market customers and small businesses (the Lifestyle Package and Small Business Package) that structure the demand charge into a volumetric \$/kWh charge that is more familiar to customers.</p> <p>Furthermore, as foreshadowed in this Explanatory Notes document, we are exploring further intermediate network tariff options that will assist customers in their transition to cost reflectivity and future capacity based tariffs.</p>
	Customers asked whether the use of LRMC is appropriate in a low growth period.	<p>Basing our tariffs on LRMC is a requirement of the NER.</p> <p>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 DER.</p> <p>As a result, we anticipate that demand tariffs will transition to capacity tariffs over time. In recognition of these emerging trends, we are exploring intermediate network tariff options which are discussed in these Explanatory Notes.</p>
	Tariffs are calculated on the same flawed LRMC estimates.	Same response as 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 & Australia's competitive advantage	Same response as above.
	Some stakeholders seek efficient tariffs that are reflective of the spare network capacity.	<p>These concerns may be addressed through the intermediate network tariff options being considered in these Explanatory Notes.</p> <p>We invite stakeholders to provide feedback as part of the AER's TSS consultation process.</p>
	Certain load profiles take place outside the summer months, and yet these loads receive only moderate reduction in costs	Same response as above.
	Some stakeholders expressed concerns that if the top-up charges 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.	<p>LRMC is incorporated in both the capacity band and peak summer top-up charging parameters of the suite of Package tariffs. This provides the appropriate signals to customers about their impact to their network with respect to their network capacity requirements and contributions to</p>

Issues	You Said	We Said
		network peak demands.
	Certain customers are open to the networks exploring a model that derives a LRMC on a current and future focussed network.	Our current LRMC methodology is detailed in Section 6.2 of these Explanatory Notes. 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 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	We are exploring intermediate network tariff options (as set out in these Explanatory Notes) to better manage the impact on small customers, recognising the need to gradually transition customers to the demand concept and eventually the capacity concept through intermediate network tariff options.
	Some stakeholders suggest adjustments to the Lifestyle Package to reduce bill shocks.	Same response as above
	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.	Same response as above Furthermore the Lifestyle Tariff is proposed to be offered to customers as an optional tariff in the 2020-25 regulatory control period.
	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 is a matter for the Queensland Government. However as noted above we are exploring intermediate network tariff options that take into account customer impact.
DER contribution to network capacity	Customers 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 LV network performance given the ubiquitous investment in DER that is occurring and the benefits available to enhance capacity of the network. The intermediate capacity tariff options being explored are a critical component of this consideration.
Supporting customers	Some stakeholders recommend additional support to assist customers to understand the Lifestyle Package.	We agree with this position. We are considering developing supporting material as part of the TEDI framework in partnership with retailers.
Tariff Assignment	Customers expressed concern that mandatory assignment would take control away.	We are continuing to explore tariff assignment as noted elsewhere in this document. The principles of equity and fairness continue to underpin TSS development. Further feedback from customers and stakeholders as part of the AER's TSS consultation process is expected.
Equity	Large customer advocates seeking equitable treatment for their customer user group – in terms of a share of savings from reduced overall revenue requirements and removal of	Reduced revenue requirement will benefit all customers all customers, including large customers. Business and Commercial Package options

Issues	You Said	We Said
	cross subsidies.	offer opportunity for enhanced choice and control of the network bill. Developing tariffs that reduce cross subsidies remains a priority.
	Some stakeholders are seeking concrete details around the extent of cross-subsidies as well as on the proposed timing to eliminate these cross-subsidies.	<p>We are committed to implementing new and innovative cost reflective tariffs. However, the pace of tariff reform needs to take into account customer impact.</p> <p>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 customers and stakeholders we have included customer impact analysis in this Explanatory Notes document.</p>
Tariff choice	Agricultural advocates suggesting there is an opportunity around a 'genuine optimised control load tariff for crops such as sugar cane'.	<p>Dynamic Response tariffs are being explored as outlined in Appendix A.</p> <p>We invite stakeholders to provide feedback as part of the AER's TSS consultation process.</p>
	<p>Some stakeholders have identified the complexity of understanding the difference between the standing and market offers from each of the retailers in the market.</p> <p>Adding another tariff option in addition to the existing suite of tariffs may escalate the level of complexity of retail market offers.</p>	<p>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.</p> <p>We agree that more needs to be done to reduce the risk of confusion for customers. We intend to work collaboratively with retailers to ensure education and information material is developed to support tariff.</p>
Determination of peak period	Customers recognise that there are periods where the network faces peak demand constraints. However customers requested a review of the original summer peak window dimensions.	We have undertaken a review of the summer peak window dimensions and made adjustments to the season in the case of residential customers and time of day for small business and business customers.
Jurisdictional Schemes	Some stakeholders noted that Ergon Energy did not include any allowance for the costs associated with jurisdictional schemes such as the Solar Bonus Scheme.	<p>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.</p> <p>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.</p>