Ergon Energy is enabling customers with greater choice and control over how they want to use the network while still delivering peace of mind through a safe, dependable electricity service…all for the best possible price.

Why has this reform been necessary? In short, it’s because the way our customers are using the network is changing. And the way we charge has not kept up – it has, in fact, even contributed to electricity prices rising.

We embarked on our reform journey in 2012-13, very much aware we must continue to meet everyone’s needs into the future for the best possible price with fairer, more equitable pricing signals. We wanted to give our customers the opportunity to save, but in a way that reduces the costs of supplying energy for everyone.

We now have a much greater appreciation of how we can structure prices so they better reflect what drives our costs as a network provider and we are reforming our pricing signals to better align with these costs.

This means real savings can now be offered when the network is not being used to its full capacity, and that we are better placed to charge appropriate, ‘cost reflective’ rates during peak period windows in the summer months. It is at these times that the level of demand is more likely to drive future capital investment.

Purpose of this Tariff Structure Statement

This Tariff Structure Statement provides accessible and comprehensive information on our network tariffs and how they are expected to change in the future. It:

- provides an explanation of network tariffs and other key concepts discussed in the document
- outlines our proposed tariff structures for 2017 to 2020
- explains the key steps in our approach to compliance with the National Electricity Rules
- outlines how our network tariffs are expected to change in 2016-17 and the remaining three years to 2019-20
- provides indicative annual rates for our Standard and Alternative Control Services for 2017 to 2020
- links to the stakeholder engagement overview, Appendix A, on how we have engaged with customers and retailers.
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1. Introduction

In November 2014, amendments to the National Electricity Rules (NER) fundamentally changed the framework in which network tariffs are developed. These changes included obligations on Distribution Network Service Providers (DNSPs), including Ergon Energy, to develop prices that better reflect the costs of providing services to customers so they can make informed decisions about how they use electricity.

This Tariff Structure Statement (TSS) is part of this new framework. The TSS aims to transparently show how Ergon Energy applies the new pricing principles to develop our price structures for Direct Control Services. It also provides indicative annual tariffs for the 2017 to 2020 period. The approved TSS will remain in place for the regulatory control period.¹

The TSS interfaces with Ergon Energy’s Pricing Proposal, which is submitted each year for approval by the Australian Energy Regulator (AER). Each Pricing Proposal must be consistent with the approved TSS. However, actual rates in the Pricing Proposal are expected to differ from the indicative schedules provided in the TSS. We will explain the reasons for these differences in the relevant Pricing Proposal.

1.1 Our network

Ergon Energy supplies electricity across a vast, diverse service area of more than one million square kilometres – across 97% of the state of Queensland.

Around 70% of our electricity network runs through rural Queensland, with large distances between communities. Over two thirds of our customers are located outside Queensland’s urban population centres. We service communities from regional Queensland’s expanding coastal population centres, to the most remote parts of outback regional Queensland and the Torres Strait.²

Ergon Energy’s network has been designed, and continues to evolve, to best meet the needs of our customers. This includes responding to the specific needs of our network and customer base, including:

- the significant distances over which assets must be constructed. We have a high proportion of costly sub-transmission assets, compared to our urban counterparts, and one of the largest limited capacity, radial Single Wire Earth Return networks in the world
- the volatile and often harsh climatic environment, including exposure to extreme weather events, which requires us to maintain a significant emergency response capability. In some areas we have seasonal access only due to very significant levels of rainfall.

¹ Due to transitional arrangements, this TSS covers 2017-18 to 2019-20 only.
² Ergon Energy supplies communities isolated from the main grid, in western Queensland, the Gulf of Carpentaria, Cape York, various Torres Strait islands, and Palm Island. The pricing arrangements for these customers do not form part of our TSS.
Figure 1: Ergon Energy’s service area
With only 7% of all customers across the National Electricity Market (NEM), but covering 44% of the total geographic area, the unique nature of Ergon Energy’s network makes the cost of providing services in our network area high, compared to the average network service provider.

Figure 2: Ergon Energy elements as a proportion of the NEM

1.2 Our customers

Our pricing arrangements reflect a complex mixture of different customer types across a multitude of pricing zones. Ergon Energy provides electricity to a population of 1.5 million people – through over 730,000 customer connections.\(^3\)

- Around 725,000 of our customers use less than 100 MWh of electricity a year – of these, 86% are residential customers and 14% are small to medium businesses.
- Our remaining customers are regional Queensland’s largest commercial and industrial operations.
  - We have around 8,000 large business customers, using between 100 MWh and 4 GWh a year, operating throughout regional Queensland.
  - The next largest group are the 200-odd customers using over 4 GWh of electricity a year – requiring an ‘extra-large’ level of network capacity and in many cases a dedicated connection.
  - Our largest energy users, using over 40 GWh a year, are the extra-large coal-mining related operations linked to the Bowen, Surat and Galilee basins. Although only a small number of customers, they make up around 30% of the total energy load on Ergon Energy’s network.

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\(^3\) As at 30 June 2015.
1.3 Our network tariff reform journey and future plans

Addressing electricity affordability is a core part of our strategy and commitment to customers. We have been driving hard to reduce our costs as a business. Over the next five years our expenditure overall is forecast to be more than a billion dollars less than the last five years. This provides an ideal environment for network tariff reform.

We are also focused on enabling an effective market. Our longer term business model involves developing an enabling platform that supports the interaction between the various parties seeking to use our network. Ergon Energy is also looking to advocate for other changes in the electricity industry that, over time, make it easier and more cost-effective for customers, small generators, solar and battery installers, application developers, energy efficiency providers and product manufacturers to do business together.

Our efforts to move our network prices towards a cost reflective framework over the last few years form part of these efforts. Our reform pathway is also consistent with the direction policy-makers are encouraging all network businesses to follow through changes to pricing obligations.

We are seeking to:

- align drivers of customer usage with network investment and our operational cost drivers
- address distortionary pricing signals that lead to cross subsidies between different users and an overall increase in the cost of energy delivery.

Managing and even encouraging energy consumption, without placing additional stress on the network or costly infrastructure investment, is critical to ensuring electricity is affordable to all going forward.

When we embarked upon our network tariff reform journey three years ago we were acutely aware of the need to address the ongoing affordability of our electricity distribution services. While we were working hard to ensure our network could meet the changing needs of our customers, our network charges had not kept pace. Our objective was to ensure we could continue to meet everyone’s needs into the future for the best possible price and to deliver fairer, more equitable pricing signals.
Our reforms were aimed at giving all customers the opportunity to save, by looking at what drives our costs and aligning our pricing signals appropriately. We focused on changes that would allow us to offer real savings when the network is not being used to its full capacity, and to charge cost reflective rates when the level of demand across the network is likely to drive future capital investment. Ergon Energy builds new infrastructure largely to keep up with demand during the summer months.

We understood the need to move steadily on these reforms, but we also knew we needed to act to avoid electricity prices rising unnecessarily into the future. This is why we have been talking to customers and stakeholders and working hard ourselves to develop and move to the best tariff structures for regional Queensland.

As part of our network tariff strategy, we have established 2016-17 as the foundation year for our network tariffs. From there, we plan to keep our tariff structures relatively stable, using the TSS period to build a greater understanding of the new tariff options and promote their benefits.

---

**Figure 4**: Our reform journey has placed us well for a period of implementation

### 1.4 Scope of the Tariff Structure Statement

#### 1.4.1 Direct Control Services

Consistent with the NER, this TSS covers Ergon Energy’s Direct Control Services. There are two types of Direct Control Services:

- **Standard Control Services (SCS)** – what customers see as their ongoing day-to-day access and use of the distribution network
- **Alternative Control Services (ACS)** – user-specific distribution services.

Each of these is described further in Table 1 below.

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4 NER, clause 6.18.1A. Direct Control Services are distribution services that are subject to direct regulatory oversight by the AER through a price or revenue setting.
Table 1: Direct Control Services

<table>
<thead>
<tr>
<th>Direct Control Services</th>
<th>Description</th>
<th>Examples of services</th>
<th>Cost recovery</th>
</tr>
</thead>
</table>
| SCS                     | Core distribution services associated with the access and supply of electricity to all customers | • Network services (e.g. construction, maintenance and repair of the network)  
  • Small customer connections  
  • Type 7 metering services | • Distribution Use of System (DUOS) charges |
| ACS                     | Other distribution services requested by a customer, retailer or appropriate third party | • Fee based services (e.g. de-energisations)  
  • Quoted services (e.g. major customer connections)  
  • Default Metering Services (Type 5 and 6 meters)  
  • Public Lighting Services | • User-specific charges that are directly levied on the party to whom the service is being provided |

Our TSS has been structured to address SCS and ACS separately, as the methodologies underlying the development of each are fundamentally different.

1.4.2 Mount Isa distribution system

In addition to our grid-connected network, the AER is responsible for the economic regulation of the Mount Isa–Cloncurry isolated network owned by Ergon Energy. Under the NER, Ergon Energy must provide a separate TSS if we own, control or operate more than one distribution system, unless the AER otherwise determines.

On 23 September 2015, Ergon Energy informed the AER of our intention to submit one TSS, which encompasses both the grid-connected network and the Mount Isa–Cloncurry network. The AER endorsed this approach on 9 November 2015.

1.5 Further information

Further information on our network tariff reform journey and the consultation we have undertaken to inform the development of this TSS is available on our website at: [www.ergon.com.au/futurenetworktariffs](http://www.ergon.com.au/futurenetworktariffs).

If you have any queries, please contact us at:

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Phone: 13 74 66  
Email: futurenetworktariffs@ergon.com.au.

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5 Electricity National Scheme (Qld) Act 1997, section 10.  
6 NER, clause 6.8.2(e) (as amended by transitional clause 11.73.2(a)).
Part 1 – Our approach to network tariffs and stakeholder engagement
2. **Our approach to network tariffs and stakeholder engagement**

2.1 **Our approach to network tariffs**

2.1.1 **New regulatory requirements**

The Australian Energy Market Commission’s (AEMC) 2012 Power of Choice Review focused on the need to increase the economic integrity of signals faced by end-use electricity customers and to increase the scope for them to respond to these enhanced signals. Policy-makers took the view that if retail customers faced tariffs that better reflected the costs of meeting demand, they would have incentives to change their behaviour in ways that could reduce overall system costs.

Changes to the NER followed the Power of Choice Review. In addition to requirements regarding the process for developing a TSS, the NER was amended to expand upon the principles that Ergon Energy must address when establishing prices.

2.1.2 **Our network tariff reform journey**

Our journey of network tariff reform, which commenced in 2012-13, predates changes to the NER. Nevertheless, the outcomes of our reform program closely align with the changing direction in the NER. Very early on, we saw the necessity to change our pricing arrangements, given the unique nature of our network:

> To the extent that network charges have not been reflective of costs to date, and customers have responded to those tariffs, customer consumption decisions are likely to have moved away from the economically optimal. This in turn impacts on the load shape presented to the network, capacity requirements of the network, the overall distribution cost base and customer affordability.\(^7\)

---

Our journey involved seeking customer and stakeholder input to assist us clearly map out a future pathway for network tariffs that:

- is transparent and sustainable
- provides guidance for future decision making for customers and other stakeholders.

Our objective was to ensure we could continue to meet everyone’s needs into the future for the best possible price and to deliver fairer, more equitable pricing signals. To do this, we developed specific reform pathways for each of our customer groups, with the first steps of reform undertaken in July 2014. A number of guiding themes aided our consideration and assessment of the options available to us.

---

Our approach has been to move gradually, and transparently, toward more efficient pricing to best manage any customer impacts and implementation issues. We were working hard to ensure our network could meet the changing needs of our customers, but our network charges had not kept pace with these changes, contributing to rising electricity prices.

We were also driving hard to reduce our costs as a business and were confident we would be able to deliver the savings needed to provide an ideal environment for tariff reform. This early start has allowed us to develop a network tariff strategy, with a transparent reform pathway which is managing the impact on individual customers.

As we have already noted, affordability of our network services for customers is a key driver of our tariff reform agenda. Previous research for Ergon Energy found that the impact of increasing uncoordinated solar photovoltaic (PV) penetration and continuation of ‘legacy’ tariff arrangements may result in customers paying $1 billion more than necessary in the future.8

Legacy pricing structures create the wrong customer response, and this distorted response means that some customers pay more than they should be for using the network while other customers are paying less. Responding to inefficient price signals increases suboptimal bypass of the centralised energy system. This impacts the network via higher voltage management costs and falling utilisation. The cost to serve customers through the network thereby increases, incentivising more bypass – again, with no corresponding reduction in network prices.

There are implications for both the network and retail businesses, but also the economy as a whole, as the total cost of delivering energy in Ergon Energy’s network area becomes less efficient.

Our preferred future is one that provides the right signals to customers so that the choices each customer makes in using the network is reflected in the price they pay (and not in the price other customers pay).

The other important consideration in our approach has been the need to create value in the network for those seeking to adopt new and emerging energy-related technologies. Our reforms allow these innovations to be accommodated where it makes sense, and deliver real value to those investing in their own solutions, like solar and battery storage combinations, without being cross subsidised by other network users. Our approach also supports technologies, like electric vehicles, that could significantly boost the utilisation of the network, which helps reduce the unit cost of supplying electricity for all.

The tariff themes guiding our reforms and the foundation for tariffs in 2017-20 include:

- reducing our over-reliance on volume (kWh) charges
- implementing time-of-use as a critical dimension of cost reflective tariffs
- aligning demand charges to the incremental network costs associated with the demand or the LRMC
- rebalancing between demand (aligned with Long Run Marginal Cost outcomes) and fixed charges
- using kVA more widely as the unit of measure in our network tariffs.

---

2.2 Our stakeholder engagement program

Since commencing our engagement process in 2013, Ergon Energy has released six key consultation papers with supporting documentation and held five dedicated consumer advocacy sessions and a series of webinars. Following suggestions from stakeholders, we also developed a short video to assist consumers to understand the reforms. Opportunity to comment was provided on five occasions, resulting in over 80 formal submissions.

Ergon Energy has made efforts to reach our different customer classes and respond to requests for further information.

Our consultation on network tariffs has helped us develop the initial strategy, implement reforms and refine the pathway, and more recently helped us prepare our TSS.

Figure 5: Stakeholder engagement is playing a key role in our journey

The channels used for our engagement included:

- qualitative interviews
- stakeholder sessions
- our Customer Council and other Ergon Energy-led industry forums
- open webinars
- published consultation papers

The primary stakeholder groups we engaged included consumer representatives, very large customers, retailers, regional stakeholders and interested customers, and regional Queensland’s solar installers/electrical contractors.
2.2.1 What our customers want

The major themes in the responses included:

- **significant concern around the rise in electricity prices in recent years**: this has created a tension, as network prices are a significant component of the bill, between a recognition of the need to remove the cross subsidies in tariffs that exist as early as possible and the need for more time to ensure customers are able to respond to the changes.

This has led to general support for the voluntary nature of the new tariff options now being made available and the staged introduction of other reforms.

- **desire for a greater understanding around the customer impacts/opportunities in the new voluntary demand-based tariffs**: this is seen as key to being able to educate customers appropriately and, ultimately, for them to be confident in choosing to adopt the new tariffs. It will also be important to ensuring there are adequate protections for customers.

- **concern around the ability of some customers to respond to the price signals and control the timing of their demand**: while these concerns do exist, there is a growing understanding of how the path we have been progressing along can support the best price outcome for all, over the longer term.

Further information on our network tariff reform journey and the consultation we have undertaken to inform the development of this TSS is available in Appendix A. The documentation created throughout this process is also available on our website at: [www.ergon.com.au/futurenetworktariffs](http://www.ergon.com.au/futurenetworktariffs).
Part 2 – Standard Control Services
3. **Understanding network tariffs**

3.1 **Your electricity bill**

A customer’s retail electricity bill has a number of components (see Figure 6).

![Components of a customer’s retail electricity bill](image)

**Figure 6: Components of a customer’s retail electricity bill**

As illustrated by the above diagram, the bill a customer receives from retailers incorporates our network charges, as well their energy and retail costs. The charges a retailer receives from us (the NUOS charges) are further broken down into:

- what Ergon Energy charges for the use of our network (DUOS charges)
- what Powerlink charges Ergon Energy for TUOS (Powerlink’s costs of transmitting energy from generators to our network) plus other transmission-related charges
- payments made to eligible customers under the Queensland Government’s Solar Bonus Scheme which Ergon Energy is required to recover (jurisdictional scheme charges).

In summary, Ergon Energy’s NUOS charges include the costs we charge for the use of the network (DUOS) but also include the costs we pass on to customers that are outside our control (TUOS and jurisdictional scheme charges).

We also determine charges for ACS (see Part 3 of this TSS). These charges do not form part of the NUOS charges billed to retailers. Rather, they are separately levied on the customer or retailer requesting the service. The most common user-specific charge found on a customer’s retail bill relates to metering.

3.1.1 **The impact of network tariffs on a retail bill**

Each year the Queensland Competition Authority (QCA), under a delegation from the Queensland Government, sets regulated retail electricity prices or ‘Notified Prices’ based on its latest forecasts of providing electricity services. To calculate each regulated retail tariff (apart from historical transitional tariffs), the QCA uses a ‘Network plus Retail’ cost build-up approach. The underlying
network cost component may be based on our network tariffs and/or rates, or those of Energex Limited (Energex).

For the majority of our customers their retail bill is subsidised by the Queensland Government in line with the Uniform Tariff Policy. This policy, and the associated Community Service Obligation payment made by the government to our retailer (Ergon Energy Queensland Pty Ltd), ensures that Queenslanders generally have access to the same cost of electricity, regardless of where they live.

For residential and small to medium business customers, who use less than 100 MWh of electricity a year, this means our network tariff – the Inclining Block Tariff (IBT) – and our rates for all tariff structures are not used as the basis for the QCA’s regulated retail tariffs. These tariffs, which are accessed by the majority of customers in regional Queensland, are largely based on Energex’s network charges for south east Queensland. However, our reforms are helping to introduce greater choice for this group.

For businesses using more than 100 MWh of electricity a year, Ergon Energy’s network tariffs are typically passed on through the QCA’s Notified Prices. However, there are some exceptions.

The impact of Ergon Energy’s network tariffs also depends on whether a customer is on a regulated retail tariff(s) or on a contract with a competitive retailer. For customers on a ‘market contract’, their retailer will determine if or how our rates or tariff structures are passed through.

### 3.2  Key concepts in tariff design

There are a number of pricing concepts discussed in this TSS. To assist understanding, we have explained these concepts below.

#### 3.2.1  Tariff classes

We have a wide diversity of customers, in terms of their size, location, and usage patterns. We group our customers according to these characteristics. Tariff classes therefore refer to a group of customers with similar characteristics. Ergon Energy has 18 tariff classes for SCS customers. These tariff classes are detailed in Section 4.1.

#### 3.2.2  Tariff structures, charges and charging parameters

A tariff represents the combination of charges that Ergon Energy applies to a customer (through their retailer) in order to recover network costs (or NUOS as referred to in Section 3.1 above). Within each tariff class a number of tariffs can be offered.

Tariffs have three key defining characteristics:

- the charge (can also be called ‘charging component’, ‘tariff component’ or ‘tariff element’)
- the parameters of the charge (specific characteristics that relate to the charge that influence how it is calculated)
- the rate applied to each charge.

Each tariff has at least one charge, but usually has more than one. Ergon Energy uses six broad types of charges and charging parameters for our SCS as shown in Table 2.
Table 2: Types of charges and charging parameters

<table>
<thead>
<tr>
<th>Charge</th>
<th>Charging Parameter</th>
</tr>
</thead>
<tbody>
<tr>
<td>Fixed charge</td>
<td>Represented as a rate per day. Structures for most tariffs include a fixed charge.</td>
</tr>
<tr>
<td>Volume charge</td>
<td>Represented as a rate per kWh. Structures for most tariffs include a volume charge. However, different parameters apply to this charge for different tariffs. These are explained in Chapter 4. Within a tariff structure, volume charge rates can be flat or be applied to different blocks (based on consumption) or times (peak and off-peak).</td>
</tr>
</tbody>
</table>
| Demand charge       | Represented as either a rate per kW or a rate per kVA. Most tariffs include a demand charge. Different parameters apply to this charge for different tariffs. These are explained in Chapter 4. Within a tariff structure demand charge rates can be:  
  - applied year round or seasonally (with different peak and off-peak rates)  
  - calculated based on:  
    - a single period in the month  
    - the maximum demand within a peak demand window  
    - an average of demands within a peak demand window.  
  Some tariff structures include a floor (the demand charge must include at least the rate times ‘X’ demand) or a threshold (the demand charge is only calculated for demands recorded above a particular level). |
| Capacity charge     | Represented as a rate per kVA. Sections 4.6 and 4.7 outline the application of capacity charges for our ICC and CAC tariffs. |
| Excess reactive power (kVAr) charges | Represented as a rate per excess kVAr. Sections 4.6 and 4.7 outline the application of excess reactive power charges for our ICC and CAC tariffs. |
| Connection unit charges | Represented as a rate per connection unit per day. Section 4.6 outlines the application of connection unit charges for our CAC tariffs. |

3.2.3 Our pricing zones

Unlike most other DNSPs, Ergon Energy develops prices for three different pricing zones. These are based on geographic areas of the network where costs are assessed to be broadly similar. These pricing zones are:9

- **East Zone** – those areas where the network users are supplied from the distribution system connected to the national grid and have a relatively low distribution cost to supply
- **West Zone** – those areas outside the East Zone and connected to the national grid, which have a significantly higher distribution cost to supply compared to the East Zone
- **Mount Isa Zone** – broadly defined as those areas supplied from the isolated Mount Isa system. This zone is not connected to the national grid and, as such, would normally be excluded from the application of the NER. However, under the *Electricity – National Scheme (Queensland) Act 1997*, the Queensland Government has transferred responsibility for the economic regulation of the Mount Isa–Cloncurry supply network to the AER.

9 Areas supplied from isolated (remote) generation are not included in any of the below zones. The local government areas covered by each zone and a map depicting each zone are located in the *Information Guide for Standard Control Services*. 
4. **Tariff structures**

This chapter details our tariff classes and their respective network tariff structures, including charging parameters, which will apply in 2016-17 to 2019-20.

4.1 **Tariff classes**

Ergon Energy will continue to support 18 tariff classes for our SCS in the 2017 to 2020 period. These tariff classes are consistent with those applying in 2015-16.

Our selection of SCS tariff classes aligns with our cost allocation process for tariff-setting by differentiating between:

- **customer groups**
  - Individually Calculated Customers (ICC)
  - Connection Asset Customers (CAC)
  - Standard Asset Customers (SAC)
    - SAC Large
    - SAC Small
    - SAC Unmetered
  - Embedded Generators (EG)

- **locational zones**
  - East Zone
  - West Zone
  - Mount Isa Zone.

For example, we have a tariff class for ICCs in the East Zone, West Zone and Mount Isa Zone.

Table 3 below outlines all the tariff classes by group and region.

**Table 3: Ergon Energy’s SCS tariff classes**

<table>
<thead>
<tr>
<th>Customer group</th>
<th>East Zone</th>
<th>West Zone</th>
<th>Mount Isa Zone</th>
</tr>
</thead>
<tbody>
<tr>
<td>ICC</td>
<td>●</td>
<td>●</td>
<td>●</td>
</tr>
<tr>
<td>CAC</td>
<td>●</td>
<td>●</td>
<td>●</td>
</tr>
<tr>
<td>EG</td>
<td>●</td>
<td>●</td>
<td>●</td>
</tr>
<tr>
<td>SAC Large</td>
<td>●</td>
<td>●</td>
<td>●</td>
</tr>
<tr>
<td>SAC Small</td>
<td>●</td>
<td>●</td>
<td>●</td>
</tr>
<tr>
<td>SAC Unmetered</td>
<td>●</td>
<td>●</td>
<td>●</td>
</tr>
</tbody>
</table>

Tariffs and tariff structures differ between customer groupings. However, there is no difference in tariff structures within a customer grouping across the pricing zones. In other words, the same tariff structures apply to CACs in the East, West and Mount Isa Zones. Only rates tend to differ between pricing zones. Because of this we are likely to engage with stakeholders on streamlining our tariff classes as part of our consultation for the TSS to apply from 2020.
4.2 Residential and small to medium business customers (SAC Small)

Ergon Energy offers a range of network tariffs to our residential and small to medium business customers who use less than 100 MWh of electricity per year. At the highest level, these network tariffs are:

- Inclining Block Tariff (IBT)
- Seasonal Time-of-Use Energy (STOUE)
- Seasonal Time-of-Use Demand (STOUD).

Like all tariff classes these network tariffs are further differentiated by the location of the customer’s premises. That is:

- East, West or Mount Isa Zone
- TUOS Region 1, 2, 3 or 4.

For this customer grouping, there is also a further classification depending on whether the customer’s connection is classified as residential or business (non-residential). Some of the charging parameters are different depending on this additional level of classification.

Our SAC Small tariff structures are explained in further detail below, with a complete list of network tariffs and indicative prices available in Appendix D.

It is important to note that most residential and small to medium business customers are not directly impacted by our underlying network tariffs. This is because the Notified Prices for these customers are not based on Ergon Energy’s network tariffs.

For the small percentage of customers in this class (approximately 0.4%) who are on competitive retail contracts – typically the larger business customers – the impact will depend on arrangements with the customer’s retailer and how they decide to respond to our network tariffs.

4.2.1 Inclining Block Tariffs

Ergon Energy will continue to offer a three step inclining block structure for the 2017 to 2020 period. Under this tariff structure, the price per kWh increases as consumption thresholds are crossed during a particular time period.

Ergon Energy introduced these tariffs in 2014-15 as a transitional step toward more cost reflective tariffs. We noted, at that time, that the IBT will go some way to better reflect costs when compared to our previous flat energy based tariffs (without requiring metering changes at the premises).

This is because shared network costs are largely fixed, with the exception of augmentation capital expenditure which is driven by increases in peak demand. The introduction of the IBT structure enabled the move towards higher fixed charges, while also mitigating their effect for customers with low levels of consumption.

Based on current regulatory arrangements, new connections and customers to Ergon Energy will be assigned to an IBT, unless an alternative tariff is requested. To the extent that regulatory arrangements change to allow retailers more autonomy over metering service provision, Section 4.2.3 outlines circumstances where a customer may be assigned to a demand tariff in the first instance (with the option for them to choose an alternative tariff if they prefer). In any case, over the longer term, Ergon Energy will need to transition to a greater penetration of cost reflective tariffs.
tariffs and we will consult on possible transition paths as part of our 2020 TSS consultation process.

**Charging parameters**

The IBT is structured with a fixed charge per day and three energy consumption blocks, each with a different energy (volume) charge applicable.

The fixed charges and energy charges for each consumption block are different between the East, West and Mount Isa Zones. The block sizes and energy charges for each consumption block are also different between residential and business customers.

The IBT is denominated and applied on a daily basis. However, it may be described in the context of an annual basis for network tariff consultation and presentation purposes. Daily denomination ensures IBT billing is equitably applied for any meter reading period (including instances where a customer move-out/move-in occurs) based on an accumulated total of consumption divided by the number of days in the reading period. More information on the calculation can be found in our *Network Tariff Guide for Standard Control Services*.

**Changes since 2015-16**

To align the IBT with the Long Run Marginal Cost (LRMC) pricing principle, we have changed the rate for the first 1,000 kWh of annual consumption from zero dollars per kWh to a positive rate that is consistent with progressively reflecting the LRMC as an annualised volume rate.

The increase in the rate for the first IBT consumption block will avoid, in the first instance, the need to increase the fixed charge. This will result in a lower customer impact for low consumption customers (<1,000 kWh p.a.), than recovery of the equivalent revenue in the fixed charge.

This change in 2016-17 will be the first step in a transitional process that is expected to be largely completed in 2017-18.

4.2.2 **Seasonal TOU Energy tariffs (STOUE)**

In 2014-15, SAC Small customers were given the option to move to a time-of-use (TOU) energy-based tariff. Similar tariffs are currently used elsewhere in Australia. However, our offer includes seasonal and time-of-day dimensions that mirror regional Queensland's unique seasonal loads (hence the name, Seasonal Time-of-Use Energy or STOUE).

The times of day when higher peak charges apply reflect the times when the network is more likely

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10 For example, the annual equivalent of Block 1 is <1,000 kWh p.a.
to experience peak demand conditions. In Ergon Energy’s case, this is on all days during summer months in the mid-afternoon and evening for residential customers, and from late morning to early evening on summer weekdays for business customers.

The STOUE was the first step in removing the cross subsidies and distortionary incentives for inefficient customer response that are inherent in legacy tariffs. Under this tariff structure, customers are provided lower energy prices for consumption in off-peak times, when compared to the second and third IBT consumption block rates. They are also given more visibility of the higher costs associated with consumption in peak periods compared to off-peak times (when prices are significantly lower). Therefore, STOUE tariffs are aimed at greater cost reflectivity and customer choice.

A retailer must request a tariff change to opt in to these tariffs. The benefit of the STOUE tariffs compared to demand-based tariffs is they are available without the need to upgrade to remote read metering. Nevertheless, access is subject to compliance with tariff metering and associated requirements.

**Charging parameters**

The STOUE is structured with a fixed charge per day and an energy (volume) charge which includes seasonal, day of week and time-of-day dimensions. These dimensions are based on analysis of zone substations servicing regional Queensland’s business and residential load profiles across the different seasons of the year.

The rate for the energy charge for the summer peak period is higher than the energy charge for the off-peak time periods.

The peak and off-peak time periods and the energy charges for each time period are also different between residential and business customers.

The fixed charges and energy charges for each time period are also different between the East, West and Mount Isa Zones.

**Changes since 2015-16**

To align with the STOUD structure, we have consolidated the shoulder and peak energy charges (including time periods) into one peak energy charge.

This simplifies the tariff for retailers and customers and is a natural progression from our 2015-16 STOUE tariffs, where the shoulder and peak rates were the same. It also allows the LRMC charge (which has been revised higher to reflect the new LRMC pricing principle) to be applied over a longer period, reducing the LRMC rate to be applied, without diluting the signal.
4.2.3 Seasonal TOU Demand tariffs (STOUD)

Since 1 July 2015, SAC Small customers with appropriate metering capability have had the option to choose a demand-based tariff that incorporates seasonal, day of the week and time-of-day dimensions. The structure and the rates associated with each component reflect the cost associated with placing additional demand on the network, especially in the summer months.

When compared to the STOUE, it allows us the opportunity to refine the visibility of the cost of investment at peak times even further. This, in turn, allows more favourable prices outside the peak charge periods.

Charging parameters

The STOUD is structured with demand charges and an any time energy (volume) charge.

The monthly demand charges, for both summer and non-summer, are based on the average demand the customer places on the network in the daily demand window.

For business customers, the demand window is the half hours between 10.00 am and 8.00 pm on weekdays. For residential customers, the window is the half hours between 3.00 pm and 9.30 pm each day of the year.

We look at the highest four demand days in the month, determined by the average demand recorded in these daily demand windows. We apply the monthly demand rate to the average of these top four demand days.

This more moderated application of the peak charging mechanism (compared to measuring a single half hour period of maximum demand) minimises the bill impact of any abnormally high peak demand days. It also improves the likelihood of the period measured coinciding with the network wide peak (peak demand drives our costs, so any opportunity to reduce this demand will benefit all customers).

In the non-summer months, the kW rate applied to the off-peak demand charge is much lower. The only other difference is that a 3 kW floor also applies. This means the customer pays for 3 kW of demand, or the average of their top four average demand days in the month, whichever is the greater. This mechanism has allowed us to remove fixed charges for DUOS throughout the summer months.\textsuperscript{11}

A flat energy charge is applied all year round.

\textsuperscript{11} Customers will still see some fixed charges relating to jurisdictional schemes, transmission costs and retail.
The lower rates set in this tariff for off-peak demand and energy means real savings for customers 90% of the time, when the network is not being used to its full capacity.

At the moment a customer (via their retailer) must request a tariff change if they wish to adopt this tariff. This is subject to the provision of compliant metering. Changes to the NER may affect obligations surrounding the ownership of metering services and the availability of Type 4 metering. Depending on the outcome of these changes we may seek to apply the STOUD to all new premises connections (with installed metering capable of applying the tariff) from 1 July 2018. Even after this time customers, through their retailer, will still have the option not to have the STOUD applied to their premises and choose the alternative STOUE or IBT that we offer.

Changes since 2015-16

In response to feedback on simplifying the tariff, we have amended the calculation of the both the peak and off-peak (non-summer) demand charges. Changes were made to align the calculation of the chargeable quantity to the same approach and the same times for peak and off-peak demand, and to determine which four days were used for calculation based on the average demand over the entire daily peak period, rather than the highest four single half hour daily demands during the peak period.

We are also progressively increasing the proportion of LRMC incorporated in the peak demand charge. This will strengthen the cost reflectivity of the STOUD tariffs.

4.3 Secondary tariffs

4.3.1 Controlled load

Many customers, in addition to their primary tariff, enter into arrangements with Ergon Energy whereby some appliances are subject to a secondary “controlled tariff”. Controlled load tariffs allow Ergon Energy to directly curtail supply to designated circuits at a customer’s premises in return for a lower tariff than the ones applying to uncontrolled load.

Ergon Energy offers three controlled load tariffs:

- **Volume Controlled** – applies where specified permanently connected appliances are controlled by network equipment so that supply will be available for a minimum of 18 hours per day during time periods set at the absolute discretion of Ergon Energy
- **Volume Night Controlled** – applies where specified permanently connected appliances are controlled by network equipment so that supply will be available for a minimum period of eight hours a day at the absolute discretion of Ergon Energy, but usually between the hours of 10.00 pm and 7.00 am
- **Demand Controlled** – applies where a customer has agreed for load to be actively controlled by Ergon Energy to reduce demand at system peaks while not impacting on a customer’s utility, at the absolute discretion of Ergon Energy. This tariff supports products such as PeakSmart air-conditioning

**Charging parameters**

Each of our controlled load tariffs has a fixed charge ($/day) and an any time energy (volume) charge ($/kWh).
Changes since 2015-16

In 2015-16, a process was started to rebalance controlled load rates so that our application of LRMC and residual cost recovery are relatively consistent between primary and secondary tariffs. Our Volume Controlled and Volume Night Controlled rates assume controlled load makes negligible contribution to peak load (as we can control the load during peak times).

We are also introducing an additional controlled load tariff – Demand Controlled – which will be available in conjunction with the STOUD Residential tariff. New products such as PeakSmart air-conditioning are supported by this tariff. Essentially PeakSmart allows Ergon Energy to partially reduce the demand of air-conditioning at times of system peak, without significantly affecting the customer’s use of the appliance. The rates for this secondary tariff take into account the network benefit associated with the reduced contribution to peak demand.

4.3.2 Potential tariff for certain micro-embedded generators

Ergon Energy notes the definition of a micro-embedded generating unit under Australian Standard (AS) 4777 may change in the future. Currently, AS 4777 captures inverters for energy systems up to 10 kVA on single phase and up to 30 kVA on three phase. In the future, AS 4777 may include inverters up to 200 kVA. We understand this change may occur in 2016 and have an effective date of 12 months after its release date.

Our SAC and EG network user group definitions currently reference AS 4777. That is:

- SACs are defined as: “All other load customers. This includes customers with micro generation facilities (such as small scale PV generators) that have exporting capability and an inverter capacity as per Australian Standard (AS) 4777.”
- EGs are defined as: “Those network users that export energy into the distribution system. EGs do not include micro-embedded generators as defined under AS 4777.”

If a change to AS 4777 proceeds, micro-embedded generators with inverters between 30 kVA and 200 kVA would move from our EG network user group into the SAC network user group. This means the current fixed charge which applies to the generation side of their connection would cease to apply. Given the size of the generation connected, this would lead to an increased risk of cross subsidy between customers without export and these customers.

To ensure a consistent and equitable approach across the regulatory control period, we have made changes to our SAC and EG network user group definitions. Specifically, we have made reference to AS 4777.1 – 2005, the standard that applied as at 1 July 2015. This means the generation side of micro-embedded generators with inverters between 30 kVA and 200 kVA will continue to be treated as an EG.

If the AER does not agree with this approach, and the regulatory change occurs, we may need to develop a secondary (mandatory) tariff for micro-embedded generators with inverters between 30 kVA and 200 kVA to ensure all customers are treated on an equitable basis.

Charging parameters

This potential tariff will consist of a fixed charge ($/day). This fixed charge will apply to the generation side of micro-embedded generators with inverters between 30 kVA and 200 kVA.

12 To the extent the inverter size definition is lower or higher, we would amend the conditions of this tariff to reflect AS 4777.
In addition, DUOS tariffs for the load side will apply. These tariffs will be allocated as per the appropriate SAC Large or SAC Small customer group.

4.4 Unmetered supplies

This customer group takes supply from our network, but no meter is installed at the connection point. Unmetered supplies within our network area include public lighting, traffic lights, watchman lights and other types of unmetered public amenities (e.g. illuminated signs, phone boxes and barbeques etc.).

Charging parameters

Like controlled load, unmetered supplies comprise two charging components – fixed ($/day/device) and any time energy (volume) charges ($/kWh).

4.5 Commercial industrial and rural industry customers (SAC Large)

Our SAC Large customer group consists of commercial, industrial and rural industry customers who use between 100 MWh and 4 GWh of electricity a year.

Ergon Energy offers up to five types of network tariffs to these customers in each pricing zone:

- Demand High Voltage
- Demand Large
- Demand Medium
- Demand Small
- STOUD.

Our SAC Large tariff structures are explained in further detail below, with a complete list of network tariffs and indicative prices available in Appendix D.

4.5.1 Demand tariffs

These general demand-based tariffs allow customers to reduce their network tariff costs by reducing peak demand and/or total energy use.

Charging parameters

Our demand tariff structures have a fixed charge, an actual demand charge and any time energy (volume) charge.

The actual demand charge is based on the maximum amount of electricity used in any one half-hour time period in the monthly billing period. It applies to the customer’s actual demand above a set threshold, which varies depending on the type of tariff.

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13 East Zone only.
Changes since 2015-16

Ergon Energy will continue to phase out the Demand High Voltage tariffs. This tariff will only be available in the East Zone and is not available to new customers.

Possible introduction of kVA charging

As part of our network tariff strategy, we considered the introduction of kVA charging for our SAC Large customers. We recognise that this type of charging provides price signals to encourage customers to manage demand and influences voltage outcomes.

However, the introduction of kVA in the SAC Large tariff structures will not be progressed in the current TSS period. This is because the preferred approach to implement power factor improvement price signals for this class of customers requires additional development and consultation. We will consult with stakeholders further on this issue as part of the development of the TSS applying from 2020.

4.5.2 Seasonal TOU Demand tariffs

Since 1 July 2015, SAC Large customers with appropriate metering capability have had the option to choose a STOUD tariff. Like the STOUD for SAC Small customers, the structure and the rates associated with each component reflect the cost associated with placing additional demand on the network, especially in the summer months. It provides the opportunity for savings for customers for 90% of the time, when the network is not being used to its full capacity.

A customer (via their retailer) must request a tariff change to opt in to these tariffs. This is subject to the provision of tariff compliant metering.

Given the tariffs for SAC Large customers are usually self-selecting, our preference would be, from July 2017, for new premises and customers moving into existing premises for this customer group (with the required metering) to be subject to this tariff (with the option of choosing the general demand tariffs if desired).
Charging parameters

The STOUD has peak and off-peak demand charges, an off-peak energy charge and a fixed charge.

Unlike the average demand peak charge for residential and small to medium business customers, the summer peak demand charges for this customer group are based on the monthly maximum demand recorded in any single half hour between 10.00 am and 8.00 pm on a summer weekday (December, January and February). This monthly demand charge is applied to the kW amount by which this monthly maximum demand exceeds 20 kW (the demand threshold applicable to the peak period).

Similarly, for non-summer months, a demand charge will be applied to the kW amount by which the recorded monthly maximum demand exceeds 40 kW. This demand may occur at any time during the month (i.e. it is not limited to between 10.00 am and 8.00 pm on a weekday). Obviously, where the monthly metered maximum demand is less than the demand threshold, the chargeable demand for that month is set to zero.

An energy charge is applied to all energy consumed in non-summer months. A fixed charge also applies throughout the year.

Changes since 2015-16

We are progressively increasing the proportion of LRMC incorporated in the peak demand charge. This will strengthen the cost reflectivity of the STOUD tariffs.

4.6 Large commercial and industrial customers (CAC)

Typically customers in this group include large industrial sites, large mining, manufacturing and farming operations, sugar mills, large shopping centres, hospitals, universities, correctional centres, defence force bases and large pumping stations.

Prior to 1 July 2015, each customer in this group was priced individually to take into account their relative share of asset use and the assets built for their specific connection. In response to feedback over the need for more simplicity and transparency, we introduced changes in 2015-16 to reduce the number of tariffs and individual calculations.

This resulted in the introduction of:

- four standardised tariffs in each pricing zone:
  - CAC 22/11 kV Line
  - CAC 22/11 kV Bus
  - CAC 33 kV
  - CAC 66 kV

- a connection unit charge comprised of a standard daily fixed charge that is applied against each customer’s individual number of connection units. This effectively maintains a connection charge per customer which is reflective of the connection assets dedicated to them.

Consistent with our general direction to look at what drives our costs and aligning this with our pricing signals, we also introduced the following optional STOUD tariffs:

- STOUD CAC 22/11 kV Line
- STOUD CAC 22/11 kV Bus
• STOUD CAC Higher Voltage (66/33 kV).

Our CAC tariff structures are explained in further detail below, with a complete list of network tariffs and indicative prices available in Appendix D.

4.6.1 CAC standardised tariffs

Charging parameters

Our standardised CAC tariff structures have six charging parameters.

The actual demand charge is based on the maximum amount of electricity used in any one half-hour time period in the monthly billing period. It applies to the customer’s actual demand (kVA).

The excess reactive power (kVar) charge is calculated monthly based on the power factor recorded at the time of each customer’s individual monthly kVA peak. To the extent the actual kVar exceeds the customer’s permissible kVar quantity (determined by the customer’s authorised demand and the NER compliant power factor), excess kVar charges are applied.

The capacity charge is applied to the customer’s individual kVA authorised demand.\(^{14}\)

The connection unit charge is multiplied by the customer’s number of connection units. For customers that connected to the network on or after 1 July 2015, no connection units will apply.

A fixed charge and a flat energy (volume) charge apply throughout the year.

Changes since 2015-16

We have introduced an excess reactive power charge or excess kVar charge. This charge reinforces the price signal introduced by the kVA tariff in 2015-16, which encourages customers to improve their power factor and reduce their usage of network capacity.

It will replicate the charge currently applied to ICCs when a customer’s demand for kVARs exceeds a permissible quantity\(^{15}\) which is specific to each customer.

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\(^{14}\) In order to convert the authorised demand to kVA, we used a site’s power factor (the ratio of real power (kW) to total power (kVA)). This was done by taking the highest power factor from a premises’ most recent 12 months of meter data at the monthly peak in demand. Ergon Energy will review this each year.

\(^{15}\) Permissible quantity is calculated with reference to the customer’s authorised demand and the minimal compliant power factor as specified in the NER.
4.6.2 CAC Seasonal TOU Demand tariffs

Charging parameters

Like our other STOUD tariffs, our CAC STOUD tariff structure includes a peak demand charge, a capacity charge (off-peak demand) and an off-peak energy charge. However, the manner in which the demand charges apply is different.

The peak demand charge is based on the customer’s monthly maximum kVA demand during the peak period in each summer month. The capacity charge is based on the greater of the customer’s authorised demand and the actual monthly half hour maximum demand. The capacity charge applies for all 12 months of the year. Over the summer months, it excludes demand occurring during the peak demand window of 10.00 am to 8.00 pm on summer weekdays.

The off-peak energy charge is applied to all energy consumed in non-summer months.

In addition, an excess reactive power charge and connection unit charge apply. These charges are calculated in the same manner as the corresponding charges in the standardised CAC tariffs.

Changes since 2015-16

We have made the following changes:

- The LRMC demand charge is no longer based on the greater of the authorised demand and monthly maximum demand during the peak period.
- The capacity charge is no longer charged on the greater of a monthly floor and the monthly maximum demand during the non-summer months.

We have also introduced a new excess reactive power charge, consistent with changes made to the standardised CAC tariffs.

We are confident that this structure will improve incentives for CACs to respond to the LRMC signal.

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**THE TARIFF COMPONENTS**

Charges drop in non-summer months and in non-peak times in summer months

Non-summer off-peak energy charge ($/kWh)
Total energy consumed in non-summer months

Capacity charge ($/kVA/mth)
Greater of the authorised demand or the monthly actual maximum demand (all year excluding summer peak demand window times)

Connection unit charge ($/day per connection unit)
All year, as applicable

Excess reactive power charge ($/excess kVAR/mth)
Applied against the kVAR used by a customer that exceeds the customer’s permissible quantity

Dec Jan Feb Mar Apr May Jun Jul Aug Sep Oct Nov

There are five charging components for the CAC STOUD: a peak demand charge in summer months, a capacity charge, an off-peak energy charge in non-summer months, a connection unit charge, and an excess reactive power charge.
### 4.7 Individually Calculated Customers (ICC)

Customers in our ICC network user group generally use more than 40 GWh of electricity per year and comprise large coal mining customers and customers involved in other types of mining, transport (rail) and pumping operations.

**Charging parameters**

Our ICC network tariffs are comprised of a fixed charge, a capacity charge, an actual demand charge, an excess reactive power charge and a volume charge.

The actual demand charge is based on the maximum amount of electricity used in any one half-hour time period in the monthly billing period.

The capacity charge is applied to the customer’s individual kVA authorised demand.

For these types of customers, the premises’ power factor is important. Distribution systems must be designed to supply the actual power required and a low power factor means actual power delivered will be unnecessarily high. The excess reactive power charge encourages customers to improve their power factor and reduce their peak network capacity requirements.

A customer’s kVAr is calculated monthly based on the power factor recorded at the time of their individual monthly kVA peak. To the extent the customer’s kVAr exceeds their permissible quantity, charges are applied.

A fixed charge and a flat energy (volume) charge apply throughout the year.

**Changes since 2015-16**

We reviewed the current ICC tariff structure with respect to alignment with the LRMC pricing principle and concluded that the existing structure is consistent with the LRMC pricing principle. Therefore, no changes have been made.

**Future improvements**

In looking at options for improving LRMC signals for this tariff class, we believe there may be opportunity to improve the signal a customer receives for exceeding their authorised demand. Our analysis suggests that introducing an excess demand charge, where demand exceeds the customer’s authorised demand, may be a way to improve this signal.

We have also looked at possible changes aimed at ICCs reducing their authorised demand, reducing their contribution to shared network costs via their capacity charge and actual demand charge even though the reduction will do little to reduce Ergon Energy’s avoidable costs (as these costs are largely sunk).
We will not make changes for this TSS but we will look to engage with customers on this option with a view that this could be introduced in the regulatory control period 2020-25.

4.8 Embedded Generators (EG)

EGs are those network users that export into our distribution system (other than micro-embedded generators with inverters of the kind contemplated under AS 4777.1 – 2005).

Charging parameters

The NER specifically prohibit DUOS charges being applied for the export of electricity generated by the user into the distribution network.

For those EGs that generate into the distribution system, a fixed charge ($/day) applies. This charge recovers the costs associated with connection assets and network user management services provided to this customer group.

Similarly, a fixed charge applies to the generation side of those EGs that generate into, as well as take load from the distribution system. In addition, DUOS tariffs for the load side apply. These tariffs are allocated as per the appropriate network user group (i.e. ICC, CAC or SAC).
5. Meeting the pricing principles

This chapter addresses how our network tariffs satisfy the pricing principles contained in the NER. These pricing principles were modified by the AEMC in November 2014. In this chapter, we:

- outline the network pricing objective and consider the expectations from changes made to the NER
- explore our tariffs in the context of:
  - avoidable and stand-alone costs
  - Long Run Marginal Cost (LRMC)
- set out how our tariffs recover our allowed revenues in an efficient and least-distortionary manner
- build on our theme of affordability for customers in the context of the likely impact on retail customer bills.

5.1 Network pricing objective

The network pricing objective is that distribution network tariffs payable by a retail customer should reflect a DNSP’s efficient costs of providing Direct Control Services to that customer. Under the NER, DNSPs are required to comply with the distribution pricing principles in such a way that contributes to the achievement of the network pricing objective.

In its final determination on the *Distribution Network Pricing Arrangements* rule change, the AEMC explained that:

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*The focus of the network pricing objective is cost reflectivity. Cost reflectivity in relation to network tariffs has three key components:*

*(i) Sending efficient signals about future network costs.*

*(ii) Allowing a DNSP to recover its regulated revenue so that it can recover its efficient costs of building and maintaining the existing network.*

*(iii) Each consumer should pay for the costs caused by its use of the network.)*

* Taken together, these three components of cost reflectivity should result in an outcome where the network prices that each consumer faces reflect the costs that particular consumer causes through its use of the network.*

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The AEMC defined cost reflectivity in the network pricing objective by reference to the very same matters that are the subject of the pricing principles. This gives rise to circularity between the objective and the pricing principles. The pricing principles themselves stress the need for tariffs to:

- be subsidy-free
- reflect LRMC
- recover the remainder of a DNSP’s regulated revenue in a least-distortionary manner.

There is not much further guidance as to how Ergon Energy should satisfy the pricing principles in such a way as to contribute to the network pricing objective, beyond that tariffs must be cost reflective, in that:

- they must send efficient signals about future costs
- allow the DNSP to recover its regulated revenue
- ensure customers pay for costs they cause.

In other words, the objective does not provide any additional guidance to DNSPs about how to apply the pricing principles other than what is embodied in the principles themselves.

To overcome this circularity, Ergon Energy has chosen to interpret the network pricing objective to mean that network tariffs should meet the pricing principles in such a way that promotes economic efficiency across the three dimensions described below:

- **Productive efficiency** – is achieved when DNSPs produce their goods and services at the least possible cost. To achieve this, DNSPs must be technically efficient (produce the most output possible from the combination of inputs used) while also selecting the lowest cost combination of inputs given prevailing input prices.

- **Allocative efficiency** – is achieved where resources used to produce a set of goods or services are allocated to the user that provides the greatest benefit relative to costs. To achieve this, prices of the goods and services of DNSPs must reflect the productively efficient costs of providing those goods and services.

- **Dynamic efficiency** – reflects the need for industries to make timely changes to technology and products in response to changes in consumer tastes and in productive opportunities. This implies that customers should have incentives to invest in network alternatives, such as solar PV or demand-side response, where the costs of such alternatives are less than the costs of delivering additional power through the distribution network.

In developing the network tariffs outlined in Chapter 4, and in the future as we continue to refine our existing tariff structures, we have and will strive to apply the pricing principles in such a manner that promotes these dimensions of economic efficiency.

### 5.2 Avoidable and stand-alone costs

For each tariff class, the revenue expected to be recovered must lie on or between:

1. an upper bound representing the stand-alone cost of serving the retail customers who belong to that class
2. a lower bound representing the avoidable cost of not serving those retail customers.

Cross subsidies between tariff classes will arise where tariffs recover revenues outside the bounds of the stand-alone and avoidable costs. This is why the pricing principles embody the need for
tariffs to recover network revenues no less than the avoidable costs of serving a customer tariff class and no more than the stand-alone costs of serving a tariff class.

Ergon Energy interprets stand-alone and avoidable costs in the following manner:

- **Stand-alone costs** for a tariff class are the costs of establishing and maintaining infrastructure to service a single tariff class as if no other tariff classes needed to be served. They represent the upper bound costs of providing a service for a particular tariff class. Assuming that no other tariff classes use network infrastructure means that the economies of scale and scope from using a shared network to serve customers across multiple tariff classes are ignored.

- **Avoidable costs** are the costs which would be avoided by Ergon Energy not providing a distribution service to a particular tariff class, assuming all other tariff classes continued to be served. Therefore, if Ergon Energy was to cease providing services to CACs in our West Zone, the avoidable cost methodology assesses the extent to which our costs would be reduced as a result.

Our approach to determining these costs for our SCS is set out in Appendix B. This appendix also demonstrates that, for each SCS tariff class containing retail customers, the expected revenue in each year of the 2016-17 to 2019-20 period lies on or between the lower bound avoidable cost and the upper bound stand-alone cost.

Since the expected revenue is indicative only at this stage, Ergon Energy will re-calculate the avoidable and stand-alone costs each year and publish the revised calculations in the relevant annual Pricing Proposal.

### 5.3 Long run marginal cost

Each tariff must be based on the LRMC of providing the service to which it relates to retail customers assigned to that tariff with the method of calculating such cost and the manner in which that method is applied to be determined having regard to:

- the costs and benefits associated with calculating, implementing and applying that method as proposed
- the additional costs likely to be associated with meeting demand from retail customers that are assigned to that tariff at times of greatest utilisation of the relevant part of the distribution network
- the location of retail customers that are assigned to that tariff and the extent to which costs vary between different locations in the distribution network.

The NER formerly required that each tariff and, if it consisted of two or more charging parameters, each charging parameter of a tariff class “take into account” the LRMC for the service or, in the case of a charging parameter, for the element of the service to which the charging parameter relates.

The recent changes to the NER increased the weight placed on LRMC in tariff-setting.

The pricing principles in clause 6.18.5(f) of the NER now require each tariff to be “based on” the LRMC of providing the service to the retail customers assigned to that class, with the method of

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17 Ergon Energy does not apply the avoidable and stand-alone cost test to our EG tariff classes as they are not ‘retail customers’ under the National Electricity Law. The tariffs we assign to these customers recover the cost of dedicated connection assets for the generator and do not reflect their use of the shared network.
calculating such cost and the manner in which that method is applied to be determined having regard to:

- the costs and benefits associated with calculating, implementing and applying the method
- the additional costs associated with meeting incremental demand for the customers assigned to the tariff at times of greatest utilisation of the relevant part of the distribution network
- the location of customers and the extent to which costs vary between different locations.

In response to the new NER obligations, Ergon Energy prepared or commissioned a number of reports, which we used to consult with customers on our approach to calculating and applying LRMC to network tariffs. These reports include:

- Consultation Paper: *Aligning Network Charges to the Cost of Peak Demand*, March 2015
- Supporting Document: *Long Run Marginal Cost Considerations in Developing Network Tariffs*, March 2015 (LRMC considerations report)
- Supporting Document: *Estimating the Average Incremental Cost of Ergon Energy’s Distribution Network* by consultant, Harry Colebourn (the Colebourn report)

These reports explain our LRMC calculation methodology as well as how LRMC could be applied to our tariff structures and rates. Appendix C consolidates many of the key elements of our LRMC calculation and application to prices which we have consulted on through the above documents. We provide an overview of the key elements below.

Both the calculation of LRMC and the application of LRMC to tariff-setting can be undertaken in a number of different ways and the NER does not prescribe the specific approach that DNSPs must take to these matters. Ergon Energy’s approach to implementing the greater emphasis on LRMC in the NER has been as follows:

- After consultation and consideration, we have used the Average Incremental Cost (AIC) methodology for deriving the estimates of LRMC we will apply in tariff-setting.
- Our inputs to the calculation of AIC were sourced from our October 2014 Regulatory Proposal and included:
  - network demand and related capital costs
  - operating and maintenance expenditure associated with demand related capital costs
  - incremental network demand
  - rate of return
  - power factor.
- In applying the LRMC to tariff classes, we looked at:
  - the high-level trade-offs involved in establishing LRMC-based tariffs
  - the various tariff options for charging components and charging parameters.
- We applied a process for developing LRMC signalling structures for each tariff class based on:
  - our assessment of the extent and manner in which real world conditions diverge from the simple stylised conditions that informed our high-level thinking on applying LRMC to tariff-setting
  - our assessment of the likely economic efficiency consequences of making various compromises or trade-offs between different options.
our assessment of practical considerations in setting efficient tariffs, such as the role and implications of distributed energy resources.

- We identified a peak period that best reflected network peak demand based on analysis of zone substation load profiles, taking into account random and systematic factors. We identified this by the major customer type associated with the substation load (residential and business).
- In accordance with the NER, we also considered the impact on retail customers when considering the transition to LRMC-based pricing and, in particular, the level of LRMC that would be passed on to customers through an LRMC-based charge.

Having undertaken the above steps, Ergon Energy’s suite of tariffs now includes:

- a ‘legacy tariff’ or tariff structure that has been in place for many years and which reflects more compromises in respect of the signalling of LRMC than we consider ideal in the long run
- for all non-site specific tariff classes, an alternative optional tariff structure that customers can adopt through their choice of retail tariff. These ‘LRMC-based tariffs’ place a higher and more appropriate weight on signalling the LRMC of using the distribution network.

### 5.3.1 Application of LRMC to tariff-setting

#### SAC Small legacy tariffs

Reforms to legacy tariffs for this customer group have to date included moving from a simple fixed and energy tariff to an IBT – to facilitate an increase in the fixed charge and a reduction in the average energy tariff in a way that helps mitigate adverse customer impacts.

Our intention in the medium term is to gradually rebalance the IBT such that the first consumption block (currently priced at zero dollars per kilowatt hour in the East Zone) at least reflects the value of the low voltage LRMC.\(^{18}\)

We expect the ongoing rebalancing of these tariffs in the manner described above will enable these tariffs to better reflect LRMC than they did previously. However, these legacy tariffs were not originally developed with economic efficiency in mind. Indeed, NERA’s report for the AEMC commented that modifying flat or IBT structures to better reflect the LRMC may not, in itself, promote efficiency. They suggested that DNSPs should work towards implementing more cost reflective structures over time. Ergon Energy will therefore need to phase out these tariffs over time in order to better satisfy the pricing principles in the NER.

#### SAC Large legacy tariffs

Reforms to legacy tariffs for this customer group have to date included increasing the daily fixed charge and reducing the actual demand (kW-based) charge. A key rationale for these changes was to provide signals for network usage more in accordance with the LRMC of serving these customers.

SAC Large legacy tariffs demonstrate a greater level of cost reflectivity when compared to the legacy tariff design for SAC Small tariffs. The inclusion of a charging component based on maximum demand is an example of how these tariffs better signal the network cost implications of using the network at times of high utilisation.

Nevertheless, these legacy tariffs were also not developed with LRMC-based principles in mind.

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\(^{18}\) Appendix C has more details of this calculation.
Current tariffs do not recognise the seasonal drivers of network investment. In addition, the ‘self-selection’ approach to charging components makes reform in each of the network charging categories – Demand Small, Medium, Large and High Voltage – quite complicated as changes to one parameter has a consequential impact on the attractiveness of other tariffs. Any movement to more LRMC-based pricing is likely to be gradual at best. It is more likely that Ergon Energy will need to phase out these tariffs over time in order to better meet our obligations under the NER.

**CAC legacy tariffs**

Like the SAC Large customer group, CAC legacy tariffs incorporate some element of cost reflectivity. Recent changes to these tariffs include the introduction of:

- kVA signalling for the demand charging components
- an excess reactive power charge price for customers with power factor arrangements that are outside the NER criteria.

While there is little recognition of seasonal drivers of network investment in CAC legacy tariffs, we recognise that some CACs operate at higher levels of the network and may have more dedicated assets allocated to them. It is possible that there will be some customers in this network user group that contribute a large proportion of some shared network infrastructure. In this case the signal is likely to be more reflective of the customer’s authorised demand (and less likely to be influenced by other network loads which are seasonal based). Nevertheless, we believe for the majority of customers in this network user group there will be beneficial network outcomes through a LRMC signal.

**ICC legacy tariffs**

The principal reason we have focused less on the application of LRMC to ICCs to date is that these customers tend to have less influence on the need for shared network investment than customers connected at lower voltages. Most ICCs utilise assets that are largely dedicated to one or more ICC and augmentation to these assets are typically agreed with Ergon Energy by contract rather than occurring as a consequence of our network reliability planning process. Accordingly, ICCs already face reasonable signals regarding the cost implications of their network usage decisions. Nevertheless, we will continue to explore options to ensure customers face LRMC signals by looking at the signals faced by customers when demand exceeds authorised demand or when changes to authorised demand are made.

**5.3.2 Alternative LRMC-based tariffs for all tariff classes**

In accordance with clause 6.18.5(f) of the NER, we are seeking to offer customers tariffs with structures that more closely reflect and signal the additional costs associated with meeting incremental demand at times of peak network utilisation.

Ergon Energy’s CACs and SACs presently have access to several tariffs that incorporate more cost reflective structures than their default tariffs:

- CACs can choose a STOUD tariff. For this tariff, we are progressively applying the appropriate voltage-level LRMC to the peak demand charge applied over the summer peak period.
- SAC Large customers can choose a STOUD tariff. For this tariff, we are progressively applying the appropriate voltage-level LRMC to the customer’s maximum demand (beyond a threshold) during peak times in each summer month.
- SAC Small customers can choose a STOUD or STOUE tariff. We are progressively applying the appropriate voltage-level LRMC to the peak charging components of both tariffs.

All of these tariffs incorporate a degree of seasonal, daily and time-based charging, which allows for sharper signalling of the LRMC at times of peak network utilisation.

Appendix C provides more information on how these tariffs signal the LRMC of the network.

### 5.4 Revenue recovery

The revenue expected to be recovered from each tariff must:

- reflect our total efficient costs of serving the customers assigned to that tariff
- when summed with the revenue expected to be received from all other tariffs, permit Ergon Energy to recover the expected revenue for the relevant services in accordance with the AER’s Distribution Determination.

We must also minimise distortions to price signals for the efficient usage that would result from tariffs that comply with the pricing principles set out in paragraph (f).

The pricing principles provide that where tariffs based solely on LRMC do not enable Ergon Energy to recover our efficient costs, we may structure our tariffs in order to recover our remaining ‘residual’ costs. However, where this is necessary, tariffs should be set so as to minimise distortions to LRMC-based signals.

In order to minimise distortions, regulated revenues not recovered through LRMC-based tariff parameters should be recovered through parameters that do not vary with network usage. As explained in our LRMC considerations report, a number of options are available to recover a DNSP’s residual costs. These options include:

- fixed charges ($/day)
- off-peak or any time energy charges ($/kWh)
- off-peak demand or capacity charges ($/kW demand or capacity).

Each of these options has advantages and disadvantages in terms of the distortionary signals they may provide.

Fixed charges are unlikely to send distortionary signals leading to inefficient customer response, unless they become so high that complete network bypass becomes viable for a customer. However, we note in sections below that high fixed costs can impact lower-consuming customers within each tariff class. In pursuing our objective of affordability, we need to balance the issues of distortionary signals with customer impacts.

Off-peak energy tariff charges rise with the off-peak consumption of a customer. This should have favourable distributional effects to the extent that off-peak energy consumption is correlated with customer size and financial resources. On the other hand, off-peak energy charges have some negative efficiency properties if set too high:

- Such charges will tend to inefficiently deter off-peak network usage (e.g. by high-load factor industrial customers) because the opportunity cost of such use will generally be very low.
- Customers may seek to bypass a higher off-peak energy charge through alternative sources (including solar PV). This can send distortionary price signals to customers particularly as the...
reduction in revenue received from those who have invested in alternative sources is not offset by a reduction in our costs, resulting in revenue recovery from customers who have not invested in alternative sources increasing.

This effect can be reduced if the off-peak energy rate is also relatively low.

An any time energy charge is likely to minimise distortion only if it is structured with LRMC signals in other components (i.e. if it is combined with a peak demand charge). With no LRMC signal complementing the any time energy charge, the tariff structure is likely to provide a distortionary price signal encouraging less use of the network with no corresponding reduction in network costs.

If an LRMC signal is present, setting an any time energy charge too high may over-signal the LRMC and create distortion in peak period consumption (i.e. customers inefficiently avoid peak period consumption with the combination of the LRMC signal and the high any time energy charge).

Off-peak demand tariff charges rise with the maximum off-peak demand of the customer. As such, they should have similar distributional and efficiency effects to off-peak energy tariffs. In general, the harm to economic efficiency caused by off-peak charges depends on both the:

- own-price elasticity of off-peak demand or consumption – the more price-elastic off-peak demand is, the larger the distortionary impact from a given off-peak tariff
- cross elasticity between off-peak and peak demand or consumption – the more willing customers are to shift off-peak consumption to peak periods, the larger the distortionary impact from a given off-peak tariff.

Off-peak demand tariffs will tend to benefit smaller customers but may inefficiently deter off-peak network usage, especially where off-peak usage is occasional or sporadic. This type of charge is less likely to create distortionary signals to invest inefficiently in solar PV compared to using off-peak energy to recovery residual revenue. However, if it is set too high it is likely to encourage the inefficient installation of storage for similar reasons described above.

In summary, tariff structures do require a fine balancing of charges so that prices can recover revenue allowances in the least distortionary way. Over-balancing recovery in tariff structures through any of the components can create distortionary signals and lead to inefficient customer response, resulting in suboptimal outcomes to some or all customers.

### 5.4.1 Our approach to recovery of residual costs

In establishing our tariff structures in Chapter 4, our consideration of different charging components took into account both the short term and long term responses that distortionary price signals in these tariffs could generate. This included an analysis of legacy tariffs. Where appropriate, we also balanced the need to minimise distortions with our own criteria for affordability as well as the important principles of retail customer impacts and simplicity for customers when the tariff is passed through on the retail bill.

Our analysis involved the testing of dozens of different combinations of LRMC and residual charging components. In addressing affordability for all customers, we measured the possible effects on price signals of different tariff structures and focused on those tariff combinations which demonstrated less cross subsidy and overall minimisation of community cost.
In some circumstances tariff combinations were adjusted to take into account issues of equity, simplicity and customer impact. For instance:

- Our residential and small to medium business STOUD tariffs have no fixed distribution network charge component (i.e. zero dollars per day). While a fixed charge in the tariff structure performed well in terms of revenue recovery, retail customers exhibited a preference for lower fixed charges in their final bill so Ergon Energy substituted a fixed charge rate with a higher off peak demand charge.

- Similarly, our existing residential and small to medium business STOUD tariff structures include a charging parameter for off-peak demand based on maximum monthly demand recorded. We have revised that parameter in response to customer concerns about the complexity of the existing tariff. While signalling off-peak demand across limited hours may create distortions compared to an any time maximum demand in the month, we have balanced these issues against customer concerns and perceived complexity.

- Annual demand charges scored reasonably well on a number of tariff structures. However, the application of an annual maximum demand charge can be difficult to explain to customers. On this basis, tariff structures that included annual maximum demand were not pursued.

### 5.5 Impact on retail customers

_Ergon Energy must consider the impact on retail customers of changes in tariffs from the previous regulatory year and may vary tariffs from those that comply with paragraphs (e) to (g) to the extent Ergon Energy considers reasonably necessary having regard to:

- the desirability for tariffs to comply with the pricing principles referred to in paragraphs (f) and (g), albeit after a reasonable period of transition (which may extend over more than one regulatory control period)
- the extent to which retail customers can choose the tariff to which they are assigned
- the extent to which retail customers are able to mitigate the impact of changes in tariffs through their usage decisions._

As noted above, we have been very mindful of retail customer impacts when determining the manner in which, and speed with which, different tariffs should reflect the pricing principles contained in clauses 6.18.5(e) to (g) of the NER.

In Chapter 1 we noted that a core part of our strategy and commitment to customers is our need to address electricity affordability. To achieve this, we:

- have been driving hard to reduce our costs as a business
- are focusing, over the long term, on facilitating an effective market in developing an enabling platform that supports the interaction between the various parties seeking to use our network.

Our efforts to move our network prices towards a cost reflective framework over the last few years complement our other strategies pursuing affordability. From a network tariff perspective affordability is being addressed by:

- understanding the short term and long term impacts of affordability under different tariff structures
- minimising adverse customer impacts between years
- in this early phase of implementation and transition, allowing choice and control
- aligning drivers of customer usage with network investment and our operational cost drivers
• addressing distortionary pricing signals that lead to cross subsidies between different users and an overall increase in the cost of energy delivery.

As part of our customer consultation process, we also raised possible transitional approaches to the application of the new LRMC values to peak charging components in our optional tariffs, noting that immediate transition of peak charging components to our updated LRMC value has the following challenges:

• As discussed above, our LRMC calculations were based on expectations on growth, expenditure and rate of return as at the time of our October 2014 Regulatory Proposal. These values may not be sustained in the future.

• Given the optional nature of these tariffs with a peak charging component based on LRMC, Ergon Energy needs to provide an incentive for customers on default tariffs to transition to an optional tariff. This means that we need to have regard to customers’ likely willingness to move from a legacy tariff that will only gradually reflect LRMC to an optional tariff that immediately reflects the latest LRMC value. This has encouraged us to pursue a gradual approach to the application of the LRMC values developed in the Colebourn report to our optional tariffs.

5.5.1 Customer price impacts

We have analysed the impact of each annual change to DUOS rates on individual customers over the 2017 to 2020 period. As customer circumstances change, our analysis has been limited to the customer specific impact of any tariff reform such as tariff structure changes or parameter reweighting.

For our legacy tariffs, we have deliberately moved slowly to incorporate LRMC into tariff levels so as to limit adverse customer impacts, which – particularly in an environment of rising fixed charges – tend to be particularly acute for the smaller customers within each tariff class or sub-class.

In some circumstances we have analysed a sample of customers to determine likely impacts. We have applied constraints on price impacts for tariff classes so that there is not a substantial differential in revenue recoveries between each class. We have also set maximum limits on the potential individual customer impacts (which vary depending on the extent to which general movements in revenue are increasing or decreasing) to ensure that individual customers are not, where it can be avoided, impacted excessively by the reforms.

In developing these constraints we balanced:

• the need to phase in changes progressively to provide customers with notice to respond

• the cost of retaining the inefficiency associated with tariff structures that distort customer price signals

• the NER drivers to progressively move toward a suite of tariffs that maximise achievement of the network pricing objective.

Additionally we noted that:

• Individual customer impacts attributable to tariff reform will often impact a large number of customers marginally and small number of outliers significantly.

• Overly constraining the individual customer impact will limit restructuring scope with the bulk of customers and limit the pace of realising the benefits of more efficient tariffs.

• Setting constraints at levels which are too conservative also means that new customers continue to respond to and develop their network usage to legacy price distortions for longer,
which may have more significant impacts for a greater proportion of customers than transitioning to cost reflective tariffs.

A slightly different approach was applied to ‘opt in’ tariffs. Our approach has been to ensure that our optional tariffs are relatively attractive to a large number of customers who have the choice to move, or to stay on less efficient default tariffs. Designing these tariff structures will create outliers on both sides:

- some customers may receive significantly reduced charges, indicating they have been paying more than the efficient price through legacy tariffs
- other customers may receive significantly higher charges, indicating they have been paying less than the efficient price through legacy tariffs.

We expect a slow transition to LRMC-based charges, even for those customers who are paying more than the efficient price now. Behavioural analysis also suggests that customers are unlikely to transition to something ‘new’ unless there are clear and tangible benefits. Applying constraints on customers who may be better off under more efficient tariffs would likely ensure no transition to LRMC-based tariffs. On this basis we have not applied further constraints on price impacts on optional tariffs.

5.5.2 Reflecting our network signal in regulated retail prices for regional Queensland

In earlier sections we noted that, for residential and small to medium business customers who use less than 100 MWh of electricity a year, our IBT tariff structure and our rates for all tariff structures are not used as the basis for the QCA’s regulated retail tariffs. These tariffs, which are accessed by the majority of customers in regional Queensland, are largely based on Energex’s network charges for south east Queensland.

While we have maintained an approach to calculating tariffs consistent with NER requirements and how this may impact customers, it is important to note that the extent to which these network signals are actually seen by the majority of customers in our network is also dependent on the QCA’s own review of prices and the underlying prices put forward by Energex.

5.6 Keeping it simple – easy to understand tariffs

The introduction of LRMC-based tariffs will mean that residential and small to medium business customers will see new and different tariff structures and components. The majority of these components have been known and understood by larger businesses for some time. Still, our stakeholder engagement has delivered a strong message of the need for the introduction of these tariffs to be accompanied by customer information, advice and education to allow customers to effectively respond to the new choices that are being presented to them.

We do not expect this to happen overnight. Our experience is that some customers have difficulty understanding their retail bill now, let alone some of the complicated arrangements that have
created a disconnect between the charges we apply in pricing proposals and the final rates some customers see.

Historically, customer retail prices have been set by taking relatively simple two or three part tariffs and adding a retail margin to reflect the cost of energy purchase and retailer costs. Including other tariff components in the tariff structure provides an opportunity for retailers to ‘bundle’ several different tariff components to improve understanding for customers.

We intend to engage with the QCA on developing a regulated retail tariff for residential customers that is underpinned by our cost reflective network tariff, but is offered to the customer as a set monthly rate with a certain amount of demand and volume included. In other words, network access charges are not passed through to a customer with a margin. Instead, retailers offer customers a monthly charge with excess usage fees. These rates are prevalent in similar industries (such as telecommunications and gas) and are now well understood by customers.

We expect this transition will take time and in the short term we will continue to inform customers through normal channels such as information papers and webinars. We will also look at options for providing more real time information through the use of trials or pilots and shadow billing.

5.7 Compliance with the NER and other regulatory instruments

A tariff must comply with the NER and all applicable regulatory instruments.

Our tariffs have been developed to be compliant with the NER as described in this document and Appendix J, and other regulatory instruments applicable to regional Queensland tariff development. This includes compliance with the AER’s Final Decision: Ergon Energy determination 2015-16 to 2019-20 (the ‘Distribution Determination’), in particular its control mechanism for SCS. We will demonstrate compliance with these and, where necessary, any other regulatory obligations and requirements in our annual Pricing Proposal.
6. Indicative prices

6.1 Indicative pricing schedule

Appendix D sets out indicative prices for our SCS network tariffs for 2016-17 to 2019-20.\(^{19}\)

In order to provide indicative prices, Ergon Energy forecasts a number of inputs. This means the actual prices that will apply in any given year will differ from those contained in Appendix D.

Prices may change as a result of:

- adjustments approved by the AER in the relevant pricing year (such as under or over recovery of NUOS charges and changes in inflation)
- for major customers, changes to individual customers’ circumstances (e.g. a change in connection assets, power factor, consumption, authorised demand or shared network asset utilisation)
- changes in NUOS charges not controlled by Ergon Energy (e.g. Powerlink’s transmission charges or recovery of feed-in tariff payments made in respect of the Queensland Government’s Solar Bonus Scheme)
- changes in underlying forecasts (e.g. demand and customer numbers) underpinning the estimates and incorporation of actual outcomes of forecast inputs.

6.1.1 Average price impacts for customers

We anticipate annual overall changes in the NUOS charges to remain relatively flat over the period, as shown in Figure 7.

![Figure 7: Forecast annual changes in NUOS revenue recovery](image-url)

The above figure demonstrates that the money Ergon Energy collects for the use of the network has fallen, and remains below what we recovered in 2014-15 for the remainder of this regulatory control period.

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\(^{19}\) We have provided indicative prices for each of our SAC and CAC network tariffs. However, due to confidentiality reasons, we have not published site-specific network tariffs for ICCs and EGs, or the customer-specific connection units applying to individual CACs. Doing so would breach clause 6.19.2 of the NER and any connection agreements between Ergon Energy and our customers.
The forecast increase in revenue recovery in 2016-17 is largely attributable to a forecast increase in charges to Powerlink (TUOS) and an allowance for under-recoveries from 2014-15.

The overall revenue reductions are in line with our efficiency drive and a range of other factors. A falling revenue recovery profile provides an ideal environment to manage the implementation of our tariff reform agenda.

Like our indicative prices, our total NUOS revenue recovery is expected to change as more up-to-date information becomes available.

6.2 Approach to setting each tariff 2017-2020

The approach that Ergon Energy will take to establishing tariffs in each Pricing Proposal is described in Appendix F.
7. **Assigning and reassigning customers to network tariffs**

Appendix H sets out Ergon Energy's procedures on assigning and reassigning customers to SCS tariff classes and network tariffs.
Part 3 – Alternative Control Services
8. Understanding user-specific charges

In Chapter 3, we noted that a customer’s retail bill may also include user-specific charges for ACS. These charges are levied on the customer or retailer requesting the service and are separate to the tariffs that apply for SCS.

Chapter 3 also explains key pricing concepts used in this TSS (e.g. what a tariff class is). These concepts also apply for tariffs relating to ACS. However, as most of these tariffs relate to services specific to a customer, there is less need for Ergon Energy to group customers or develop detailed structures for revenue recovery.

For ACS, Ergon Energy uses two broad types of charges:

- fixed charge
  - $ per service
  - $ per call out
  - $ per day per meter
  - $ per day per light
  - $ per light
- quoted price, determined to reflect the actual requirements of the service
  - $ per service
  - $ per call out
  - $ per light.
9. **Tariff structures**

This chapter details our ACS tariff classes and their respective tariff structures, including the charging parameters, that are proposed to apply in 2017-18 to 2019-20.

9.1 **Tariff classes**

The AER has a primary role in determining how we categorise and calculate ACS charges. The AER’s Distribution Determination (Attachments 13 and 16) provides the reasoning behind the AER’s decisions on the prices it set for the various services it classified. Ergon Energy’s tariff classes for ACS are therefore differentiated at the highest level according to the AER’s classification of services and the basis of pricing approved by the AER:

- **Fee based services** – one-off distribution services that Ergon Energy undertakes at the request of an identifiable customer, retailer or appropriate third party which are in addition to our SCS and are levied as a separate charge. These services are priced on a ‘fixed fee’ basis as the costs of providing the service (and therefore price) can be assessed in advance of the service being requested by a customer or retailer.
  
  Examples of fee based services include Type 5 and 6 meter installation and provision (on or after 1 July 2015)\(^{20}\), where the new or upgraded meter is required as a result of a customer request, de-energisations, re-energisations and supply abolishment.
  
- **Quoted services** – similar to fee based services, but they are ‘priced on application’ as the nature and scope of these services are variable and the costs (and therefore price) are specific to the individual retailer’s or customer’s needs (e.g. design and construction of connection assets for major customers, real estate development connections and special meter reads).
  
- **Default Metering Services** – relate to:
  
  - Type 5 or 6 meter installation and provision (before 1 July 2015)
  
  - Type 5 or 6 meter installation and provision (on or after 1 July 2015) where the replacement meter is initiated by Ergon Energy as a distributor
  
  - Type 5 and 6 metering maintenance, reading and data services.
  
  Ergon Energy recovers our costs of providing Default Metering Services through capital and non-capital charges based on the number and type of meters we provide the customer.
  
- **Public Lighting Services** – relate to the provision, construction and maintenance of public lighting assets owned by Ergon Energy, and emerging public lighting technology. Ergon Energy recovers our costs of providing Public Lighting Services through a daily public lighting charge billed to retailers. We also charge a one-off exit fee, which is payable when a public light is scrapped before the end of its useful operational life.

Fee based services are further separated into two tariff classes based on the type of feeder to which the customer requesting the service is connected.

We have five tariff classes for ACS, as set out in Table 4. These tariff classes are the same as those applying in 2015-16.

\(^{20}\) During business hours.
Table 4: Ergon Energy’s ACS tariff classes

<table>
<thead>
<tr>
<th>Tariff class</th>
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<tbody>
<tr>
<td>Fee based services (urban/short rural)</td>
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<tr>
<td>Fee based services (long rural/isolated)</td>
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<tr>
<td>Quoted services</td>
</tr>
<tr>
<td>Default Metering Services</td>
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<tr>
<td>Public Lighting Services</td>
</tr>
</tbody>
</table>

9.2 Fee based services

In the 2017 to 2020 period, there are 26 fee based services.

In addition, where Ergon Energy attends a premises and is unable to complete the work due to customer or retailer fault (e.g. a dangerous dog or a locked gate), we will charge a call out fee to reflect the opportunity cost of the fleet and labour resources.

Each of these services and call out fees is set out in Appendix E.

Our product range has been developed in accordance with the AER’s classification of services and is largely consistent with the services offered in 2015-16. There are two changes:

- Consistent with the Distribution Determination, there are eight new fee based services relating to the installation and provision of Type 5 and 6 meters on or after 1 July 2015 (during business hours). These services are differentiated by the type of meter (i.e. single phase, dual element, polyphase and current transformer) and the type of feeder the customer is connected to (i.e. either urban/short rural or long rural). These services replace the upfront capital charges that previously formed part of Default Metering Services. Call out fees for these services have also been developed.

- The four ‘Prevented Access’ charges have been removed. In the Distribution Determination, the AER decided that costs of wasted truck visits that are incurred in providing SCS should not be recovered through a separate ACS charge. Rather, these costs should be recovered as a SCS (i.e. via network tariffs).

9.2.1 Charging parameters

A fixed charge ($ per service) applies to our fee based services. The fixed charge reflects the estimated cost of providing each service and varies depending on the type of fee based service being requested.

The call out fee is a fixed charge ($ per call out), which varies by the type of fee based service that the original call out was for.

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21 The Distribution Determination refers to these charges as ‘upfront capital charges’.
22 Due to system limitations, in 2015-16, Ergon Energy decided to implement a transition solution for upfront metering charges associated with the installation of new meters. New installations will generally incur an upfront metering charge, plus a daily capital charge for a period of two years from the date of installation. To achieve a cost neutral outcome for the customer, the relevant AER-approved upfront metering charge will be discounted by the Net Present Value of two years’ worth of the relevant capital charge(s).
9.3 Quoted services

There are 59 quoted services available for selection during the 2017 to 2020 period. Each of these services is set out in Appendix E.

Our product range has been determined based on the AER’s classification of services and is largely consistent with the services offered in 2015-16. We have made the following changes:

- removed our ‘Install additional metering’ service in line with our revised Regulatory Proposal
- introduced a new service, ‘Installation and provision of Type 5 and 6 meters after hours’, to align with the Distribution Determination
- expanded the ‘Detailed enquiry response fee’ service to include any embedded generation connection applicant that submits an enquiry under the connection process set out in Chapter 5 of the NER. This is consistent with the Connecting embedded generators under Chapter 5A rule change, which allows non-registered embedded generators to elect to proceed under Chapter 5 of the NER and seek a detailed response
- amended the ‘Carrying out planning studies and analysis relating to connection applications’ service to include real estate developers
- removed reference to small or major customer connections from the ‘Provision of site-specific connection information and advice’ service, to expand this service to include real estate development connections.

The costs of wasted attendance for quoted services are recovered via a call out fee.

9.3.1 Charging parameters

A quoted price ($ per service) applies to our quoted services. The quoted price is based on several types and quantities of inputs that vary depending on the actual requirements of the service requested. Therefore, there will be differences in charges for each quoted service reflecting the nature of the resources required to meet the requestor’s needs.

The call out fee is a quoted price ($ per call out), which reflects the actual costs incurred in attending the premises.

9.4 Default Metering Services

Ergon Energy has developed six metering service charges, which are distinguished by:

- the type of metering service
  - primary
  - controlled load
  - solar
- the type of cost recovery
  - capital
  - non-capital

The costs of wasted attendance associated with final meter reads are recovered via a call out

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23 Metering asset base recovery and tax.
24 Operating expenditure.
25 Final meter reads form part of the cost build-up of the non-capital charges.
fee. We have established two call out fees, which are differentiated by the type of the feeder the customer is connected to (i.e. urban/short rural or long rural).

Each of these tariffs and call out fees is set out in Appendix E.

9.4.1 Charging parameters

The following charging parameters apply to Default Metering Services:

- Metering service charges – a fixed charge ($ per day per meter)
- Call out fee – a fixed charge ($ per call out).

9.5 Public Lighting Services

Ergon Energy has developed four tariffs for our Public Lighting Services, which are distinguished by:

- the ownership status
  - Ergon Energy Owned and Operated (EO&O)
  - Gifted and Ergon Energy Operated (G&EO)

- the size of the lamp
  - Major – Ergon Energy’s standard major public lights are 100, 150, 250 watt and some 400 watt High Pressure Sodium vapour lights. Major public lights also include any other non-standard or obsolete public lights that would be replaced with any of the above Ergon Energy standard major public lights in accordance with Ergon Energy policy
  - Minor – Ergon Energy’s standard minor public lights are 50, 80 and 125 watt Mercury Vapour and some 70 and 100 watt High Pressure Sodium vapour lights (special locations only). Minor public lights also include any other non-standard or obsolete public lights that would be replaced with any of the above Ergon Energy standard minor public lights in accordance with Ergon Energy policy.

The AER allows Ergon Energy to charge a one-off exit fee when a customer requests the replacement of an existing public light for a Light Emitting Diode (LED) light. We have developed four public lighting exit fees. These fees are distinguished by the ownership status and the size of the lamp. Exit fees are not payable by customers where the proposed LED transition program is being implemented.

Each of these tariffs and exit fees is set out in Appendix E and is consistent with those tariffs offered in 2015-16.

In addition, if Ergon Energy is requested by a customer to construct non-standard public lights, we may require the customer to pay an additional upfront amount towards the cost of the public lighting asset. Non-standard public lighting assets in this context are those where the cost of the service is not fully recovered through the daily public lighting charge over a 20 year term. The 20 year term represents a reasonable expectation of the average life of a public light asset.

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26 Refer to Ergon Energy’s forecast expenditure summary (public lighting services) submitted as part of our revised Regulatory Proposal for details.
9.5.1 Charging parameters

The following charging parameters apply:

- Public Lighting Services – a fixed charge ($ per day per light)
- Exit fee – a fixed charge ($ per light)
- Non-standard public lights – a quoted price ($ per light).
10. Meeting the pricing principles

Compared to SCS, Ergon Energy plays a lesser role in determining ACS prices. ACS tariffs are largely set by the AER through caps on the prices of individual services, with the majority of inputs used to develop these prices:

- being set by the AER at the time of the Distribution Determination, or
- approved by the AER during the annual pricing process.

No further allocation or structuring of the tariff is undertaken by Ergon Energy beyond the application of the control mechanism between years which is demonstrated in our Pricing Proposal.

This chapter addresses how our ACS tariffs and tariff structures meet the pricing principles, taking into account the form of control determined by the AER.

10.1 Network pricing objective

The network pricing objective requires our ACS tariffs to reflect our efficient costs of providing services to customers.

As noted above, the AER has decided to apply caps on the prices of individual ACS. This form of control generally involves the AER estimating the efficient cost of providing each service and setting the price at that cost in the first regulatory year (i.e. 2015-16). In determining the efficient cost of providing each service, the AER relies on a range of assessment techniques, including benchmarking. For subsequent years, the previous year’s prices are adjusted in accordance with the relevant price cap formula set out in the Distribution Determination.

Importantly, when setting ACS prices, the AER must promote the efficient operation and use of services for the long term interests of consumers with respect to price, quality, safety, reliability and security of supply.

For quoted services, the AER establishes an initial price cap on base labour rates. These base labour rates are then escalated annually in accordance with the quoted services formula outlined in the Distribution Determination. Other cost inputs are approved by the AER at the time of the Distribution Determination or through the annual pricing process, or are charged at cost (i.e. we pass on costs we directly incur for materials and contractor services).

Ergon Energy calculates our ACS tariffs in accordance with the relevant price cap formula set by the AER. As such, our ACS tariffs reflect our efficient costs (as determined by the AER) of providing services to our customers.

10.2 Avoidable and stand-alone costs

Our approach to determining avoidable and stand-alone costs for our fee based services, quoted services, Public Lighting Services and Default Metering Services is set out below. Consistent with this approach, we have not undertaken quantitative analysis of our stand-alone and avoidable costs for ACS.

10.2.1 Fee based and quoted services

The very nature of user-specific services means that there is a more direct link between the service the customer requests and the costs of providing the service. Ergon Energy provides our ACS
using a mix of shared and dedicated physical assets and labour. We price each of these services on a full cost recovery basis using the formulae approved by the AER.

We note the AER must establish controls over the revenue recovered or prices paid for these services having regard to the NER and the National Electricity Law. We also note in the Distribution Determination that the AER has determined charges based on what it believes will promote the efficient provision of electricity services and allow a return commensurate with the regulatory and commercial risks involved for the provision of those services. Ergon Energy prices in accordance with the Distribution Determination and relies on the application of the AER’s decision to achieve revenue recovery between the upper and lower bounds.

The use of a cost-based formula for pricing implies that if there was only one ACS tariff class provided by Ergon Energy, then total revenue for that tariff class would equal the total cost of serving that tariff class (where the total cost incurred in the provision of the service for that tariff class includes the full cost of assets used by all ACS). This means the revenue received from one ACS tariff class will not be greater than the stand-alone cost of that tariff class.

The avoidable cost of ACS is the cost incurred in the delivery of the services to a tariff class if no services were provided to any other tariff class. The only avoided costs relating to ACS are labour costs charged on an hourly basis, materials consumed during the course of providing the service and contractor services costs incurred. Given that the formula used to derive prices for fee based and quoted services includes a component of shared costs, the total revenue for tariff classes will exceed the avoidable portion.

10.2.2 Default Metering Services

Since Ergon Energy has proposed one Default Metering Services tariff class, the revenue expected to be recovered from this tariff class will be equal to the allocation of the Annual Revenue Requirement (ARR) for Default Metering Services plus any additional revenue recovered from call out fees associated with final meter reads. Ergon Energy intends to recover revenue consistent with the schedule of prices per meter determined by the AER in 2015-16, adjusted in subsequent years by the price cap formula. These prices were based on the AER’s own determination of efficient costs on a per unit basis, using a combination of high level benchmarking and assessing the assumptions used in the build-up of costs.

By applying the AER’s determination of efficient prices, we understand that the calculated prices will result in the recovery of efficient costs and expected revenue between the upper and lower bounds.

10.2.3 Public Lighting Services

Since Ergon Energy has proposed one Public Lighting Services tariff class, the revenue expected to be recovered from this tariff class will be equal to the allocation of the ARR for Public Lighting Services plus any additional revenue recovered through the exit fees. Ergon Energy intends to recover revenue consistent with the schedule of prices per light determined by the AER in 2015-16, adjusted in subsequent years by the price cap formula. These prices were based on the AER’s own determination of efficient costs on a per unit basis, using a combination of high level benchmarking and assessing the assumptions used in the build-up of costs.

Again, Ergon Energy relies on the application of the AER-determined efficient prices to result in the recovery of efficient costs and expected revenue between the upper and lower bounds.
10.3 Long run marginal cost

Each tariff and the movement in tariffs between regulatory years are determined by the AER through the application of caps on the prices of individual ACS. The AER therefore determines the LRMC of each tariff when it establishes the initial prices and sets the inputs, such as the X factors, to be used in the price cap formulae.

For fee based and quoted services, the user-pays charges recover the full cost of providing the service. Most of these costs are incremental and specific to the customer requesting the service.

For Default Metering Services, our daily metering service charges are differentiated by the type of meter (e.g. single phase) and the type of metering service requested (i.e. primary, controlled load and solar metering services). The capital and non-capital charges are calculated according to the weighted forecast average of their respective costs in the ARR.

For Public Lighting Services, our daily public lighting charges are differentiated by whether:

- the customer gifted the public light to Ergon Energy, in which case the charge recovers the costs to maintain/operate and replace the light if it fails in service before the end of its useful life
- Ergon Energy constructed the public light, in which case the charge recovers the cost to acquire, maintain/operate and replace the light if it fails in service.

Distinguishing by the type of light (Major versus Minor) also ensures the charge reflects the appropriate capital costs.

10.4 Revenue recovery

The AER, through its price cap control mechanism, sets the basis on which we are allowed to recover the efficient costs of providing each service. The total amount of revenue recovered depends on the volume of services provided in the relevant year multiplied by the rates (or the schedule of rates, as is the case for quoted services) determined by the AER.

10.5 Impact on retail customers

The price cap control mechanism limits customer impacts by constraining annual price increases to a certain level. We would expect that the AER’s Distribution Determination takes customer impacts into account when establishing structures and prices consistent with the efficient operation and use of services for the long term interests of consumers.

Customers are also able to limit price impacts by considering whether a different variant of the service may be preferable (e.g. customers can minimise the cost incurred for some services by choosing to have the service delivered during business hours, if applicable).

10.6 Keeping it simple – easy to understand charges

Our ACS are accessed by all types of customers – from residential customers to large mining operators and government entities. We therefore structure each of our ACS tariffs with a view to being as simple and easy to understand as possible, while also supporting cost reflectivity.

Each ACS tariff comprises one charging parameter only. For most ACS tariffs, this is a fixed charge – the simplest and easiest to understand charging type. We publish these fixed charges in our annual Price List for Alternative Control Services.
For quoted services, we develop a user-specific quote based on the requestor’s needs. This quote includes a breakdown of the costs we expect to incur in delivering the requested service. We also provide information in this TSS and our supporting pricing documents on how our quoted prices are determined, so that stakeholders can understand how their charge has been derived.

Our ACS tariff structures have not changed significantly from the structures that were in place in 2015-16 (which were subject to consultation through the regulatory determination process). Ongoing stability of the structures and customer familiarity with these structures assists customer understanding of the charges.

10.7 Compliance with the NER and other regulatory instruments

Our ACS tariffs have been developed to be compliant with the NER, as described in this document and in Appendix J, and other applicable regulatory instruments.
11. **Indicative prices**

11.1 **Indicative pricing schedule**

Appendix E sets out indicative prices for our ACS for the 2016-17 to 2019-20 period.

It is important to note that these prices are based on current information. Prices may change as a result of:

- the difference between forecast and actual inflation
- changes to underlying real costs (e.g. overheads, on costs, and direct materials and contractor services costs).

11.2 **Annual updates**

Ergon Energy’s ACS are regulated under a price cap control mechanism. This means the AER determines Ergon Energy’s efficient costs and approves a maximum price that Ergon Energy can charge for the service.

Our approach to establishing annual ACS tariffs under the price cap control mechanism is explained in detail in Appendix G.
12. **Assigning and reassigning customers to tariffs**

Appendix I sets out Ergon Energy’s procedures on assigning and reassigning customers to ACS tariff classes and tariffs.