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1. Introduction

1.1 Overview

On 30 June 2016, Ergon Energy Corporation Limited (Ergon Energy) became a subsidiary of Energy Queensland Limited which is the holding company for both Energex and Ergon Energy. Ergon Energy is a Distribution Network Service Provider (DNSP) to around 730,000 customers in regional Queensland. Our service area covers around 97 per cent of Queensland and has approximately 160,000 kilometres of power lines and one million power poles. Around 70 per cent of our network’s power lines are radial and service mostly rural areas with very low levels of customers per line kilometre.

Ergon Energy provides a number of different services. The Australian Energy Regulator (AER) decides how these services are classified and how they are regulated in its Distribution Determination. This is important as it determines how prices are set and how charges are recovered from our customers.

For the 2015 to 2020 period, many of our services are classified as Direct Control Services. These services are subject to direct regulatory oversight by the AER, through price or revenue setting. Direct Control Services are further classified into Standard Control Services and Alternative Control Services.

**Standard Control Services** are core distribution services associated with the access and supply of electricity to customers. They include network services (e.g. construction, maintenance and repair of the network), some connection services (e.g. small customer connections) and Type 7 metering services. We recover our costs in providing Standard Control Services through network tariffs billed to retailers.

**Alternative Control Services** are comprised of:

- **Fee based services** – one-off distribution services that we undertake at the request of an identifiable customer, retailer or appropriate third party which are levied as a separate charge, in addition to our Standard Control Services. 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.

  Examples of fee based services include temporary connections, 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 requestor’s needs (e.g. design and construction of connection assets for major customers, real estate development connections and special meter reads etc.).

- **Default Metering Services**- relate to:
  - Type 5 and 6 meter installation and provision (before 1 July 2015)
  - Type 5 and 6 metering installation and provision (on or after 1 July 2015), where the replacement meter is installed by Ergon Energy as a DNSP
  - Type 5 and 6 metering maintenance, reading and data services
Ergon Energy recovers our costs of providing Default Metering services through daily capital and non-capital charges based on the number and type of meters we provide the customer. These charges are billed to retailers.

It should be noted that the AEMC’s recommendation in the Power of choice reviews was implemented in Queensland on 1 December 2017. Under these new arrangements, we are no longer responsible for providing metering installations as they are subject to contestability. We are only able to provide metering services to existing regulated meters as long as they are in operation. As a result, on 1 December 2017, a number of Alternative Control Services were either discontinued or had the metering provision component separated from the service with the remaining components covering the services still performed by Ergon Energy.

- **Public Lighting Services** – relate to the provision, construction and maintenance of public lighting assets owned by Ergon Energy, and emerging public lighting technology. We recover our costs of providing Public Lighting Services through a daily public lighting charge billed to retailers. We also charge a one-off exit fee, when a customer requests the replacement of an existing public light for a light emitting diode (LED) luminaire before the end of its useful operational life.

We also pass on transmission-related costs and jurisdictional scheme amounts to customers.

Further information on the impact of Power of Choice on our Alternative Control Services can be found on our website at:


### 1.2 Purpose and structure

This Information Guide aims to assist stakeholders understand how network tariffs are calculated. It sets out the basis upon which Ergon Energy’s revenue cap for Standard Control Services is to be recovered from various customer groups through network tariffs, as well as a description of the network tariffs that apply in 2018-19. It also explains how transmission-related costs and jurisdictional scheme costs are passed on to customers.

### 1.3 Use of terms

The term “network tariffs” is used interchangeably with “network prices”. Network tariffs are comprised of:

- Distribution Use of System (DUOS) charges, which recover the costs of providing Standard Control Services
- Transmission Use of System (TUOS) charges

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1. We remain responsible for metering in our Mount Isa-Cloncurry and Isolated supply networks.
2. Outside of our LED transition program.
3. Jurisdictional scheme charges have been set to zero since 1 July 2017, following the Queensland Government’s direction not to pass on these charges in our network tariffs until 2020.
4. All customers supplied by Ergon Energy’s isolated generation assets are excluded from the jurisdiction of the AER and, as such, are not included in this Information Guide. The isolated generation zone is regulated by the Department of Energy and Water Supply.
- Jurisdictional scheme charges.\(^5\)

The term “network tariffs” is used by Ergon Energy to distinguish between our tariffs and retail tariffs, including the regulated retail tariffs (or Notified Prices) as gazetted by the Queensland Government.

Where the term “TUOS” is used in a section of this document, it includes all designated pricing proposal charges (DPPC) incurred for TUOS services as defined in the National Electricity Rules (NER) and set out in the Distribution Determination.

As per last year, jurisdictional scheme has not been included this year in our rates as per the Government’s direction.

### 1.4 Supporting network pricing documents

In addition to this Information Guide, we have a number of network pricing documents to assist network users, retailers and interested parties understand the development and application of network tariffs, Alternative Control Services prices and connection charges. These documents are outlined in Figure 1.1 below and are available on our website at:


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\(^5\) Refer footnote 3.
## Figure 1.1: Supporting network pricing documentation

<table>
<thead>
<tr>
<th>Documentation Type</th>
<th>Description</th>
</tr>
</thead>
</table>
| **Tariff Structure Statement**          | • Sets out the proposed tariff structures for the 2017 to 2020 period  
• Details how the proposed tariff structures comply with the pricing principles  
• Describes the tariff-setting process for Standard and Alternative Control Services  
• Provides details on the assignment of customers to tariff classes and tariffs  
• Approved by the AER in February 2017, following stakeholder consultation |
| **Pricing Proposal**                    | • Provides how Ergon Energy’s tariff classes, tariffs and tariff structures for our Standard Control Services and Alternative Control Services in compliance with the requirements set out in Chapter 6 of the NER, the AER’s Distribution Determination and our TSS  
• Provides indicative prices for 2019-20  
• Submitted to the AER annually |
| **2019-20 Network Tariff Tables**      | • Provides Ergon Energy’s prices for our Standard Control Services and Alternative Control Services developed in accordance with requirements set out in Chapter 6 of the NER, the AER’s Distribution Determination and our TSS  
• Submitted to the AER annually as part of the Pricing Proposal  
• Referred to as Attachment 1 of the Pricing Proposal |
| **Information Guide for Standard Control Services Pricing** | • Sets of the basis upon which Ergon Energy’s revenue cap for Standard Control Services is recovered from various customer groups through network tariffs  
• Provides a description of the network tariffs  
• Published annually |
| **User Guides**                         | • Provide an introduction to the current network tariffs for each customer group  
• Published annually, and updated as required |
| **Network Tariff Guide**               | • An operational document for customers, retailers and consultants, setting out the Network Tariff Codes and application rules and rates for each Network Tariff Code  
• Applies to network users connected to Ergon Energy’s regulated distribution network  
• Published annually, and updated as required |
| **Price List for Alternative Control Services** | • Sets out Ergon Energy’s Alternative Control Services and the prices that apply for fee based services. Default Metering Services and Public Lighting Services  
• Published annually, and updated as required |
| **Connection Policy**                  | • Sets out when a connection change may be payable by retail customers or real estate developers and the aspects of the connection service for which a change may be applied  
• Details how Ergon Energy calculates the capital contribution to be paid  
• Approved by teh AER in 2015 as part of the Distribution Determination |
2. Regulatory framework

2.1 National Electricity Law

Ergon Energy and the AER must have regard for the revenue and pricing principles outlined in section 7A of the National Electricity Law (the Law) when setting revenue and pricing control regimes and the resultant prices for Standard Control Services. In summary, the revenue and pricing principles are:

- a regulated network service provider should be provided with a reasonable opportunity to recover at least the efficient costs incurred in providing the services
- a regulated network service provider should be provided with effective incentives in order to promote economic efficiency
- regard should be had to the regulatory asset base of a distribution or transmission system
- a price or charge should allow for a return commensurate with the regulatory and commercial risks involved in providing the service
- regard should be had to the economic costs and risks of the potential for under and over investment in a regulated distribution or transmission system
- regard should be had to the economic costs and risks of the potential for under and over utilisation of a regulated distribution or transmission system.

2.2 National Electricity Rules

2.2.1 Tariff Structure Statement

In November 2014, amendments to the NER fundamentally changed the framework in which tariffs for Direct Control Services are developed. Included in these changes were new obligations for 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.

As part of this new framework, we must submit a Tariff Structure Statement (TSS) to the AER. The TSS sets out our proposed tariffs and tariff structures for the regulatory control period and how we have applied the new pricing principles in developing them.

The AER approved Ergon Energy’s TSS for the 2017 to 2020 period\(^6\) on 28 February 2017.

The TSS interfaces with Ergon Energy’s Pricing Proposal, and each Pricing Proposal must be consistent with the current approved TSS.

Our current TSS is available on our website (see Section 1.4).

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\(^6\) Due to transitional arrangements, our current TSS covers 2017-18 to 2019-20 only.
2.2.2 Pricing Proposal

Clause 6.18.2 of the NER requires that we annually submit a Pricing Proposal to the AER. The AER will only approve a Pricing Proposal, including the network tariffs Ergon Energy develops for Standard Control Services, if it complies with Chapter 6 of the NER and the AER’s Distribution Determination. Our Pricing Proposal for 2018-19 must also be consistent with our TSS approved by the AER.

Ergon Energy’s Pricing Proposal includes, among other things:

- an explanation of how the proposed tariff structures and tariff assignment policies satisfy the NER and AER’s Distribution Determination
- details how the tariff levels have been set and how the proposed prices satisfy a number of pricing principles outlined in clauses 6.18.5(e) to (j) of the NER and other requirements of the AER’s Distribution Determination
- information on how TUOS and jurisdictional scheme charges (if any) are to be passed through to customers
- information on how tariffs meet other compliance obligations (e.g. customer impact considerations, changes to tariffs between years, explanation of differences between proposed prices and indicative levels).

Ergon Energy’s Pricing Proposal and TSS provide additional guidance on the compliance requirements of Chapter 6, and how Ergon Energy’s network prices meet these requirements.

2.3 Distribution Determination

On 29 October 2015, the AER made its Distribution Determination for regulated distribution services provided by Ergon Energy. The Distribution Determination effectively sets the revenue and pricing control regime that we must comply with in 2019-20 for these services.

It also details how we must report on the recovery of jurisdictional scheme amounts. For Ergon Energy, this includes:

- feed-in tariff (FiT) payments made under the Queensland Government’s Solar Bonus Scheme
- the energy industry levy payable under our Distribution Authority.

2.4 Network Tariff Strategy

There has been a major shift in the way our customers use the electricity network in recent years. Strong economic growth in the early 2000s, coupled with a drop in the price of electrical appliances (including air conditioning), led to a dramatic increase in demand for electricity during peak usage periods. In more recent times, while peak demand has remained high, the economic slowdown, the growing use of solar energy and the focus on energy efficiency (as retail electricity prices have risen) has led to a drop in electricity use overall.

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7 The Distribution Determination replaces the preliminary decision released by the AER on 30 April 2015.
This means our network, which we invested in heavily to respond to the growth in demand during peak times (which can occur for only a few days a year), is now not being used as intensively as it could be outside peak times.

We are therefore restructuring the way we charge for the use of our distribution network to help ensure we maintain a viable network for our customers into the future. This process is expected to take a number of years, with the first changes implemented in 2014-15. To help develop the tariff changes, we have consulted with a wide range of our customers and our stakeholders over the past five years. The resulting short, medium and longer term tariff development intentions have been available and progressively updated on our website since June 2013, and have been subject to multiple rounds of public consultation.

Our new tariff structures are designed to allow our customers, through their retail tariff, to better understand the cost associated with accessing the network and the time they use electricity. This is particularly important when making the decisions around any future investment and use of new energy-related technologies, such as on-site generation, batteries and storage, electric vehicles, home automation, and other emergent innovations.

Our network tariff development pathway is being deployed in an increasingly dynamic industry, regulatory and market environment. With fundamental regional Queensland market changes possible in the short to medium term, and uncertainty around the level of market and customer response to the new tariffs, a tariff development pathway that is responsive to these changes is required.

While the fundamental themes, underlying drivers and future pathway of the network tariff strategy development are not expected to change, the actual rate and depth of deployment may. Our intention is to continue to consult with our customers and stakeholders, and maintain transparency of our network tariff development plans. As market reforms increasingly impact on the electricity supply industry, our network tariff structures will evolve on a continuous basis.
3. Establishing Tariffs for Standard Control Services

3.1 Overview

Ergon Energy’s Standard Control Services are regulated under a revenue cap form of price control. The revenue cap (or ‘Total Annual Revenue’) for any given year reflects our smoothed revenue requirement, as determined by the AER’s Post Tax Revenue Model (PTRM), plus other revenue adjustments. The resulting revenue cap is then recovered from various customer groups through the DUOS component of network tariffs in accordance with our network tariff development process summarised in Section 3.3.

Designated pricing proposal charges (DPPC) or Transmission Use Of System (TUOS) and jurisdictional scheme amounts are then allocated to customers.

3.2 Revenue recovery

Each year, we determine our total network (distribution, transmission and jurisdictional scheme) revenue that needs to be recovered from network users.

Clause 6.4.3(a) of the NER requires the smoothed revenue requirement\(^9\) to be determined using the building block approach prescribed under Chapter 6 of the NER. The total revenue that we will require each year over the regulatory control period is calculated in the PTRM using a build-up of operating, financing and investment costs relevant to providing our regulated services.

Other annual revenue adjustments are also applied relating to:

- the difference between forecast and actual inflation
- the updated return on debt (via a revised X factor)
- incentive scheme adjustments
- annual adjustment factors like DUOS under or over recovery adjustments
- any cost pass through amounts associated with the occurrence of any prescribed and nominated pass through events.

A detailed discussion on the calculation of the revenue cap is contained in each annual Pricing Proposal.

We also recover revenue on behalf of Powerlink and other designated pricing proposal charges, and jurisdictional scheme revenue associated with FiT payments made under the Solar Bonus Scheme and the energy industry levy.\(^10\)

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\(^9\) Also referred to as the ‘Annual Revenue Requirement’ (ARR).

\(^10\) On 31 May 2017, we received a direction from Queensland Government not to pass on jurisdictional scheme charges to customers in our network tariffs. The Queensland Government will instead subsidise the cost of the scheme until 2020. Consequently, from 1 July 2017 the jurisdictional scheme rates in our network tariffs will be set to zero.
3.3 Development of network tariffs

The development of our network tariffs involves six steps:

1. the establishment of zones where customers have a similar cost of supply
2. the calculation of the Long Run Marginal Cost (LRMC) for voltage level by zone, the allocation of the revenue cap to zones and the allocation of TUOS and jurisdictional scheme costs to customer groups
3. the allocation of the zonal costs to the different asset categories within each zone
4. the identification of network users of similar size or similar use of assets and their assignment to various network user groups
5. the allocation of the costs within the zones to the network user groups
6. the conversion of these allocated costs into network tariffs that recover those costs and are economically efficient.

The network tariffs developed for Standard Control Services are cost reflective in that there is a direct relationship between the network tariff for the service and the costs of delivering that service, derived through the methodology described in this section and depicted in Figure 3.1 below.

Further explanation of each of the six steps is set out below. Additional detail on the network tariff methodology is provided in Appendix 1. For ease of understanding the diagram, steps are presented in order of occurrence i.e. steps A2, B2, C2 and D2 occur concurrently after Step B1.
Figure 3.1: Network tariff development

* Ergon Energy’s ARR (prior to annual revenue adjustments) is determined by the AER using a building block approach. The building block components comprise allowances for return on assets (ROA), regulatory depreciation (depreciation), operating expenditure (opex) and a tax allowance. For pricing purposes, revenue associated with the tax allowance and other revenue adjustments (included in the building blocks or calculated in the revenue cap formula) is pro-rated across the ROA, depreciation and opex building block components.
Step B1: Zone determination

The first step of the overall network tariff development process is to determine the number and extent of the cost zones to be used for establishing network tariffs for Standard Control Services in the most efficient and cost reflective way.

The determination of zones is based on a combination of:

- a comparison of the distances the customers are from a Transmission Connection Point (TCP) – the further from the connection point the more distribution assets required
- minimising cross-subsidisation between the higher cost, less populated western networks, and the lower cost, more heavily populated eastern networks – the further the distance and lower the population density, the more expensive the assets and higher the cost to supply
- identifying those geographic areas which have a similar cost to supply – remote areas of western and far northern Queensland compared with the higher density eastern areas
- simplicity for customers and retailers to understand
- identifying a logical "break point" in the electrical supply network – open points in the distribution system that separate different areas of supply.

Three pricing zones have been delineated in our distribution area, broadly based on Queensland’s local government areas (LGAs), with the distribution network electrical connection being the final determinant of which zone applies. Zone pricing impacts DUOS charges only; TUOS charges and jurisdictional scheme charges (if any) are not impacted by zones.

The three pricing zones\(^\text{11}\) are:

- **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 of supply than 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.

The LGAs covered by each zone are detailed in Figure 3.2 below. A map depicting each zone is detailed in Figure 3.3 below.

\(^{11}\) Areas supplied from isolated (remote) generation are not included in any of the below zones.
Figure 3.2: Zone coverage

**East**
- **The whole LGAs of:**
  - Bundaberg (R)
  - Cairns (R)
  - Cassowary Coast (R)
  - Fraser Coast (R)
  - Gladstone (R)
  - Mackay (R)
  - North Burnett (R)
  - Rockhampton (R)
  - South Burnett (R)
  - Southern Downs (R)
  - Toowoomba (R)
  - Whitsunday (R)
  - Townsville (C)
  - Banana (S)
  - Livingstone (S)
  - Burdekin (S)
  - Hinchinbrook (S)
  - Cherbourg (S)
  - Woorabinda (S)
  - Yarrabah (S)

- **Part of the following LGAs:**
  - Gympie (R) (Ergon Energy area only)
  - Douglas (S) (excluding areas north of the Daintree River)
  - Isaac (R) (excluding areas west of Moranbah township)
  - Western Downs (R) (Dalby township and Wambo district only)
  - Central Highlands (R) (excluding Emerald and areas west of Emerald)
  - Tablelands (R) (excluding Herberton areas not supplied by the "East" distribution system)
  - Mareeba (S) (excluding areas not supplied by the "East" distribution system)

**West**
- **The whole LGAs of:**
  - Barcaldine (R)
  - Blackall - Tambo (R)
  - Charters Towers (R)
  - Longreach (R)
  - Maranoa (R)
  - Balonne (S)
  - Bulloo (S)
  - Carpentaria (S)
  - Cook (S)
  - Croydon (S)
  - Etheridge (S)
  - Flinders (S)
  - Hope Vale (S)
  - McKinlay (S)
  - Murweh (S)
  - Paroo (S)
  - Quilpie (S)
  - Richmond (S)
  - Winton (S)
  - Wujal Wujal (S)

- **Part of the following LGAs:**
  - Barcoo (S) (connected to national electricity grid only)
  - Douglas (S) (north of the Daintree River only)
  - Goondiwindi (R) (Ergon Energy supply area only)
  - Isaac (R) (west of Moranbah township only)
  - Western Downs (R) (excluding Dalby township and Wambo district)
  - Central Highlands (R) (Emerald and areas west of Emerald only)
  - Tablelands (R) (Herberton areas not supplied by the "East" distribution system only)
  - Mareeba (S) (areas not supplied by the "East" distribution system only)

**Mount Isa**

Consists of the regulated network within the whole LGAs of Cloncurry (S) and Mount Isa (C), and those parts of Burke (S) and Boulia (S) supplied from the Mount Isa system.

*Note:* (R) = Regional Council, (S) = Shire Council and (C) = City Council
Step A2: Calculating LRMC

In developing cost reflective tariffs, we must base our tariffs on the incremental costs of future network investment. This concept is known as LRMC. LRMC signals the impact customer behavior has on future network costs which, ultimately, can be avoided.\(^{12}\)

Our TSS explains our LRMC calculation methodology and our approach to incorporating the LRMC in our tariff structures and rates.

The approach to incorporating LRMC in our tariff structures and rates is dependent on:

- **Cost reflective tariffs** - for all tariff classes except ICC, an alternative optional seasonal time of use demand tariff structure(s) that customers can adopt through their choice of retail tariff. These ‘LRMC-based tariffs’ place a higher and more appropriate weight on signaling the LRMC of using the distribution network at peak times.
- ‘legacy tariffs’ – these tariffs have been in place for many years and reflect more compromises in respect of the signaling of the LRMC than we consider ideal in the long run.

This is further detailed below.

**Cost reflective tariffs**

LRMC pricing principles embody a two part tariff outcome. The first part states that the LRMC price signal while the second part addresses residual revenue recovery. In developing the LRMC-based tariffs, our objective has been to present the LRMC component through parameters which are as cost reflective as possible and aligned with enabling customer responses that support optimal use (or not) of the network.

In establishing and populating the parameters to recover residual revenue, we have targeted minimising any distortionary impact of the non-LRMC based parameters on customer response to the LRMC signals.

Therefore, our tariffs have been established with a view to developing LRMC tariff parameters that customers are likely and able to respond to, while choosing and calibrating residual recovery parameters that are less likely to distort the LRMC signals or encourage inefficient use of or by-pass of the network.

In applying these principles in 2019-20, we have not adopted full incorporation of the LRMC in the LRMC parameter for all tariffs. Instead, we are adopting a transitional approach which is expected to see the LRMC parameter progressively become stronger until 100% LRMC is achieved.

We have applied the values contained in Table 3.1 below to the peak charging component of each customer class in 2019-20. The LRMC applied for the West Zone is impacted by the sparse footprint of customers in this zone.

\(^{12}\) Chapter 10 of the NER defines LRMC as “The cost of an incremental change in demand for direct control services provided by a Distribution Network Service Provider over a period of time in which all factors of production required to provide those direct control services can be varied.”
Legacy tariffs

Efficient application of the LRMC to legacy tariffs is more challenging, given the lack of correlation between the cost of incremental change in demand and the charging parameters within each legacy tariffs. Our application of the LRMC to tariff-setting for these tariffs is detailed in our TSS.

Table 3.1: LRMC charges for 2019-20

<table>
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<th>Customer class</th>
<th>Zone</th>
<th>Calculated</th>
<th>Applied</th>
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<tbody>
<tr>
<td>Standard Asset Customers (SAC)</td>
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<tr>
<td>SAC Small Residential (STOUE &amp; STOUD)</td>
<td>East</td>
<td>300.00</td>
<td>240.24</td>
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<tr>
<td></td>
<td>West</td>
<td>751.00</td>
<td>601.39</td>
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<tr>
<td></td>
<td>Mount Isa</td>
<td>304.00</td>
<td>240.15</td>
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<tr>
<td>SAC Small Business (STOUE &amp; STOUD)</td>
<td>East</td>
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<td></td>
<td>West</td>
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<td></td>
<td>Mount Isa</td>
<td>304.00</td>
<td>298.44</td>
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<td>SAC Large (STOUD)</td>
<td>East</td>
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<tr>
<td></td>
<td>West</td>
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</table>

Step B2: Allocation of the revenue cap to zones

The revenue cap comprises the following components:

- ROA
- depreciation
- opex
- tax allowance.

Together with revenue adjustments resulting from the AER’s smoothing of the ARR, adjustments made for out-turn inflation, unders and overs in DUOS, shared assets and capital contributions,\(^{13}\) and adjustments for the Service Target Performance Incentive Scheme (STPIS), Demand Management Incentive Scheme\(^{14}\) and pass through amounts.

The tax allowance and other revenue adjustments are pro-rated across the building block cost components of ROA, depreciation and opex based on each building block’s share of the revenue cap.

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\(^{13}\) Applicable for 2015–16 and 2016–17 only, as per the Distribution Determination.
\(^{14}\) Applicable for 2016–17 only.
The final composite building block cost components are allocated to each of the three zones by apportioning each component using the following cost drivers:

- **opex** – allocated on asset values, customer numbers and energy usage
- **ROA** – allocated on asset values
- **depreciation** – allocated on asset values.

Where networks in the West Zone are supplied by shared network systems in the East Zone, the appropriate allocators are used to apportion a share of the cost to both zones.

**Step C2: Allocation of designated pricing proposal charges to customers**

**Powerlink charges**

Transmission costs are charged by Powerlink to Ergon Energy at the TCP level.

Their charges have four components:

- **Entry/Exit Connection Price ($/month)**
- **Capped Customer TUOS Usage Price: Usage Capacity Price ($/kW/month of nominated demand plus $/kW/month of average demand)**
- **Customer TUOS General Prices: General Energy Charge (c/kWh of historical energy)**
- **Transmission Customer Common Service Prices: Common Service Energy Price (c/kWh on historical energy)**.

Our network tariff calculation process allocates these components, on a cost reflective basis, to our charging structures. This conversion is shown in Appendix 1.

These charges are then apportioned to customers and/or customer groups on the following basis:

- customer numbers for the Entry/Exit Connection Price
- forecast any time maximum demand (ATMD) for the Usage Capacity Price
- forecast energy use for the remaining components.

For SAC Small, SAC Large and CACs, TCPs are allocated to one of three geographical TUOS Regions (i.e. T1, T2 or T3). TUOS charges are then calculated based on the combined totals of customer numbers, forecast demand and energy, as listed above. This has the advantage of simplifying tariffs, while still providing clear TUOS locational signals for these customers.

For those CACs that have a primary and alternate supply\(^\text{15}\) (as deemed by Ergon Energy), the following TUOS arrangements apply:

- **Primary supply** – standard rates and conditions for each charge
- **Alternate supply** – standard rates and conditions for each charge, except:

\(^{15}\) Also referred to as back-up supply.
- no TUOS fixed charge applies
- the authorised demand for the capacity charges is set at zero.

This means, with the exception of the TUOS fixed charge, alternate supplies to customers are charged at the standard rates (applicable to the voltage of the connection) for all metered quantities. However, with an authorised demand set at zero for the alternate connection, the capacity charge will only apply to the ATMD in any month when a changeover to the alternate supply takes place.

For ICC connections on site-specific charges, we take into account the fact that our customers can be supplied from different connection points depending on switching arrangements. Charges will continue to be apportioned based on the actual TCP the connection is supplied from. A weighted average methodology is applied for each of the TCPs so that these site-specific connections have cost reflective TUOS charges.

TUOS charges for CACs and ICCs are presented in kVA.

**Inter-DNSP charges**

In the Toowoomba area, we take supply from Energex Limited (Energex) at its Postman’s Ridge TCP and distribute to a group of customers in the area. This is done on economic grounds. Energex bills Ergon Energy a network service charge for these network services. These charges are forecast each year and are added to the Powerlink charges at our Middle Ridge TCP. This occurs before the allocation process identified above.

In the Mount Isa Zone, we are charged for the use of the unregulated 220 kV network which supplies the Cloncurry Township. These costs are passed through to all customers in the Mount Isa Zone via TUOS charges, using an allocation method similar to that applied to Powerlink charges in the other TUOS Regions.

**Avoided TUOS payments**

Where we are to pay an Avoided TUOS payment to an EG, the payment amount is recovered as part of the TUOS volume charges passed through to customers at the same connection point as the EG. The methodology we use to calculate the Avoided TUOS payment to an Embedded Generator (EG) is set out in Section 5.

**Step D2: Calculation of jurisdictional scheme amounts**

Jurisdictional schemes are certain programs implemented by state governments that place legislative obligations on DNSPs. Ergon Energy is subject to the following jurisdictional schemes:

- Solar Bonus Scheme, which obligates us to pay a FiT for energy supplied into our distribution network from specific micro-embedded generators

- Energy Industry Levy which we must, under our Distribution Authority, pay a proportion relating to the Queensland Government’s funding commitments for the Australian Energy Market Commission.

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16 The scheme operates under clause 44A of the *Electricity Act 1994 (Qld).*
In our 2019-20 Pricing Proposal, jurisdictional scheme amounts were not passed through to our customers.

On 31 May 2017, Ergon Energy received a direction from Queensland Government not to pass on AER-approved jurisdictional scheme charges to customers in our network tariffs. The Queensland Government will instead subsidise the cost of the scheme until 2020. Consequently, jurisdictional scheme charges are set to zero from 1 July 2017.

**Step B3: Allocation of zonal costs to asset categories**

The apportionment of the zone costs to the different asset categories within each zone occurs within our tariff development model, the Distribution Cost of Supply (DCOS) model.

The asset categories are:

- Network Operation Assets – system assets associated with monitoring and controlling the distribution network from the operational control centres
- Network Distribution Assets – system assets employed in the provision of network connection and distribution services. These assets are further categorised by voltage level as follows:
  - 110/132 kV
  - 66 kV Bus
  - 66 kV Line
  - 33 kV Bus
  - 33 kV Line
  - 22/11 kV Bus
  - 22/11 kV Line
  - Low voltage (LV)
  - Services (LV only)
  - Meters
- Other Assets – non-system assets (e.g. vehicles, computers, and buildings etc.).

The building block costs by zone are then allocated to the asset categories in the manner described in Table 3.2 below.

**Table 3.2: Subdivision of cost components**

<table>
<thead>
<tr>
<th>Opex</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Network Operating Costs</strong></td>
</tr>
<tr>
<td>Associated with monitoring and controlling the distribution network from the operational control centres</td>
</tr>
<tr>
<td>Not directly related to any single customer or group of customers</td>
</tr>
<tr>
<td>Allocated directly to the customers based on energy usage</td>
</tr>
<tr>
<td>Not applicable to EGs</td>
</tr>
<tr>
<td><strong>Network Maintenance Costs</strong></td>
</tr>
<tr>
<td>Associated with the repair and maintenance of the distribution network within the Preventive, Corrective and Forced Maintenance categories</td>
</tr>
<tr>
<td>Allocated to the voltage level asset categories based on asset values</td>
</tr>
</tbody>
</table>
Other Asset Operating Costs
  - The summation of the non-system based costs (e.g. corporate shared costs (overheads), customer services, computer systems and human resources etc.)
  - Treated as a group as it is impractical to manage a cost allocation process for each of the specific components
  - Allocated directly to the network users based on hybrid allocation of network user numbers and energy usage, and applied to all network users

<table>
<thead>
<tr>
<th>ROA</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Network Operation Assets ROA</td>
<td>Allocated to the network operations asset categories on the basis of asset values</td>
</tr>
<tr>
<td>Network Distribution Assets ROA</td>
<td>Allocated to the voltage level asset categories on the basis of asset values</td>
</tr>
<tr>
<td>Other Assets ROA</td>
<td>Allocated to the other asset categories on the basis of asset values</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Depreciation</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Network Operation Assets Depreciation</td>
<td>Allocated to the network operation asset categories on the basis of asset values</td>
</tr>
<tr>
<td>Network Distribution Assets Depreciation</td>
<td>Allocated to the voltage level asset categories on the basis of asset values</td>
</tr>
<tr>
<td>Other Assets Deprecation</td>
<td>Allocated to the other asset categories on the basis of asset values</td>
</tr>
</tbody>
</table>

Step B4: Determination of groups of network users

To provide the appropriate economic and cost of supply signals, four key groups of customers have been established (with multiple tariff classes within these groups). These groups are:

- Individually Calculated Customers (ICCs)
- Connection Asset Customers (CACs)
- Standard Asset Customers (SACs)
- Embedded Generators (EGs).

The purpose of the above four groups is to enable network tariffs to be developed that provide individual or direct cost of supply signals to those network users where possible, while recognising that it is not possible to price every network user individually. There is a trade-off at the distribution level between the complexity of individual price calculation and the inefficiencies created through price averaging. A practical limit also arises in the number of site specific network tariffs that can feasibly be determined and administered.

A description of the four network user groups is provided in Table 3.3 below.
### Table 3.3: Ergon Energy’s network user groups

<table>
<thead>
<tr>
<th>Network user group</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>ICC</strong></td>
<td>Typically reflects those customers:</td>
</tr>
<tr>
<td></td>
<td>- with energy consumption typically greater than 40 GWh per annum (p.a.), or</td>
</tr>
<tr>
<td></td>
<td>- with energy consumption lower than 40 GWh p.a. where:</td>
</tr>
<tr>
<td></td>
<td>- a customer has a dedicated supply system which is quite different and</td>
</tr>
<tr>
<td></td>
<td>separate from the remainder of the supply network</td>
</tr>
<tr>
<td></td>
<td>- there are only two or three customers in a supply system making, average</td>
</tr>
<tr>
<td></td>
<td>prices inappropriate</td>
</tr>
<tr>
<td></td>
<td>- a customer is connected at or close to a TCP, or</td>
</tr>
<tr>
<td></td>
<td>- inequitable treatment of otherwise comparable customers will arise from</td>
</tr>
<tr>
<td></td>
<td>the application of the 40 GWh p.a. thresholds.</td>
</tr>
<tr>
<td><strong>CAC</strong></td>
<td>Typically reflects those customers:</td>
</tr>
<tr>
<td></td>
<td>- with required capacity above 1,500 kVA</td>
</tr>
<tr>
<td></td>
<td>- with energy consumption typically greater than 4 GWh p.a. (but less than</td>
</tr>
<tr>
<td></td>
<td>40 GWh p.a.), or</td>
</tr>
<tr>
<td></td>
<td>- with required capacity below 1,500 kVA where:</td>
</tr>
<tr>
<td></td>
<td>- a customer has a dedicated supply system which is quite different and</td>
</tr>
<tr>
<td></td>
<td>separate from the remainder of the supply network, or</td>
</tr>
<tr>
<td></td>
<td>- inequitable treatment of otherwise comparable customers will arise from</td>
</tr>
<tr>
<td></td>
<td>the application of the 4 GWh p.a. thresholds.</td>
</tr>
<tr>
<td></td>
<td>The CAC group is further subdivided into categories based on voltage levels as follows:</td>
</tr>
<tr>
<td></td>
<td>- 66 kV – connected to either a 66 kV substation or a 66 kV line</td>
</tr>
<tr>
<td></td>
<td>- 33 kV – connected to either a 33 kV substation or a 33 kV line</td>
</tr>
<tr>
<td></td>
<td>- 22/11 kV Bus – connected to either a 22 kV or 11 kV substation</td>
</tr>
<tr>
<td></td>
<td>- 22/11 kV Line – connected to either a 22 kV or 11 kV line.</td>
</tr>
<tr>
<td><strong>SAC</strong></td>
<td>Typically reflects those customers with annual energy consumption below 4 GWh p.a.</td>
</tr>
<tr>
<td></td>
<td>Includes customers with micro-generation facilities (such as small scale photovoltaic (PV) generators) of the kind contemplated under Australian Standard (AS) 4777.1 – 2005.</td>
</tr>
<tr>
<td></td>
<td>The SAC group is further subdivided into network tariff categories based on whether:</td>
</tr>
<tr>
<td></td>
<td>- the customer’s connection is metered or unmetered</td>
</tr>
<tr>
<td></td>
<td>- the customer’s consumption relates to residential or business use</td>
</tr>
<tr>
<td></td>
<td>- the customer’s consumption is above or below 100 MWh p.a.</td>
</tr>
<tr>
<td></td>
<td>- the customer has a meter installed capable of recording demand</td>
</tr>
<tr>
<td></td>
<td>- the customer’s supply is capable of being controlled by Ergon Energy.</td>
</tr>
<tr>
<td><strong>EG</strong></td>
<td>Those network users that export energy into the distribution system, except for network users with micro-generation facilities of the kind contemplated under AS 4777.1 – 2005. EGs are separated into two categories:</td>
</tr>
<tr>
<td></td>
<td>- EGs that are connected to the distribution system and only generate into the distribution system</td>
</tr>
<tr>
<td></td>
<td>- EGs that are connected to the distribution system generate and take load from the system.¹⁷</td>
</tr>
</tbody>
</table>

¹⁷ The load side will be classified as an ICC, CAC or SAC, and a separate network tariff will apply.
Step B5: Allocation of costs within zones to network user groups

The fifth step of the overall network tariff development process is to allocate or assign the costs to the network user groups in the most efficient and cost reflective way.

Allocation of costs to ICCs

For each ICC:

- Network Operation Asset costs (i.e. ROA, depreciation and opex) are allocated on the basis of each ICC’s energy consumption.

- Network Distribution Asset costs (i.e. ROA, depreciation and opex) for both dedicated connection assets and shared assets are allocated as follows:
  - the costs are broken down by voltage level asset category and allocated to each ICC separately based on the proportion of the ICC’s replacement cost for that asset category to the whole-of-network replacement cost for that asset category.
  - the costs allocated to each ICC by voltage level asset category are summed to give the total cost for each ICC.

- Network Distribution Asset costs (i.e. opex only) for new or augmented dedicated connection assets connected under the Major Customer Connection arrangements that apply post 30 June 2010 which have been paid for upfront by the customer or alternatively assets have been gifted to Ergon Energy following construction by the customer:
  - the costs are broken down by voltage level asset category and allocated to each ICC separately based on the proportion of the ICC’s replacement cost for that asset category to the whole-of-network replacement cost for that asset category.
  - the costs allocated to each ICC by voltage level asset category are summed to give the total cost for each ICC.

- Other Assets costs (i.e. ROA, depreciation and opex) are fixed for each ICC and are calculated based on the equal sharing of the total other asset costs to be allocated to all ICCs, which is in turn based on the proportion of ICC customer numbers to total customer numbers, and the proportion of ICC energy consumption to the total energy consumption of all customers.

Allocation of costs to CACs

For CAC’s:

- Network Operation Asset costs (i.e. the ROA, depreciation and opex) are allocated on the basis of CAC’s energy consumption.

- Network Distribution Asset costs (i.e. ROA, depreciation and opex) for both dedicated connection assets and shared assets are allocated as follows:
  - for dedicated assets, costs are broken down by voltage level asset category and allocated to CAC’s based on the proportion of the CAC’s replacement cost for that asset category to the whole-of-network replacement cost for that asset category.
  - for shared assets, costs are broken down by voltage level asset category and allocated to CAC’s based on the proportion of CAC’s kW demand to the kW demand for that asset category.
the costs allocated to CAC by voltage level asset category are summed to give the total cost for CAC’s.

Network Distribution Asset costs (i.e. opex only) for new or augmented dedicated connection assets connected under the Major Customer Connection arrangements that apply post 30 June 2010 which have been paid for upfront by the customer or alternatively assets have been gifted to Ergon Energy following construction by the customer:

- the costs are broken down by voltage level asset category and allocated to CAC’s separately based on the proportion of the CAC’s replacement cost for that asset category to the whole-of-network replacement cost for that asset category
- the costs allocated to CAC’s by voltage level asset category are summed to give the total cost for each CAC

Other Assets costs have both a fixed and variable component with each component allocated 50 per cent of each CAC’s total other asset costs. The variable component is allocated to CAC’s on the basis of energy consumption.

**Allocation of costs to SACs**

Unlike ICCs and EGs, costs are not allocated directly to individual SACs. Rather, they are allocated to SAC network tariff categories according to the following process:

- the connection asset costs for each SAC network tariff category are calculated for each asset category utilised by the SAC network tariff category based on the replacement cost of those assets
- the shared network costs for each SAC network tariff category are allocated based on the ATMD of that SAC network tariff category
- Network Operation Asset costs are allocated to each SAC network tariff category on the basis of energy consumption
- Other Assets costs are allocated to each SAC network tariff category on the basis of both customer numbers and energy consumption.

**Allocation of costs to EGs**

Costs are allocated to each EG in the same manner as for ICCs including Network Distribution Asset costs (i.e. opex only) for new or augmented dedicated connection assets connected under the Major Customer Connection arrangements that apply post 30 June 2010 which have been paid for upfront by the customer or alternatively assets have been gifted to Ergon Energy following construction by the customer. Note, however, that no Network Operation Asset costs are allocated to EGs because we do not charge for Energy export to the grid.

**Step A6 and B6: Conversion of allocated costs into network tariffs**

The sixth step in the development of network tariffs is the conversion of the allocated costs for network users to network tariffs.
The network tariffs comprise a number of charging parameters, each selected and structured to provide signals to network users about the efficient use of the network and the impact of their usage on future network capacity and costs.

In developing network tariffs, we have sought to have the charging parameters signal the impact that the network users will have on the network, while:

- managing the demand and volume variance risk
- minimising zonal boundary issues between and within network user groups
- avoiding any signals that may result in perverse outcomes.

The DUOS charging parameters that have been adopted for 2018-19 are outlined in the sub-sections below.

Fixed charges

The fixed charge has been applied to serve two broad purposes. For some customers within a tariff class, it seeks to reflect the incremental costs that arise from the connection and management of the network user. The fixed charge is also used to help recover a share of residual or sunk elements of our costs. For example, for SAC Small customers, the fixed charge also recovers a portion of the shared network costs.

Fixed charges are levied on a rate ($) per day basis or rate ($) per day per device basis, as is the case for unmetered supplies (i.e. public lights). They apply to all network users, but not all tariffs. For example, no fixed DUOS charges apply to:

- SAC Small STOUD tariffs (however, a minimum off-peak chargeable demand of 3 kW per month is applied in the nine non-summer months)
- CAC STOUD tariffs.

Connection unit charges

Prior to 2015–16, customer connection charges for CACs were based on their specific connection configuration and presented explicitly through individual tariffs. This connection charge is now a standard daily charge with individual customers allocated a site-specific number of connection units. The number of units allocated reflects the value of the customer’s dedicated connection assets and whether these assets were paid upfront by the customer. A customer’s individual connection unit charge is calculated as follows:

Connection unit charge = number of units x connection unit rate ($/day) x number of days

Customers are individually advised of the connection unit multiplier value attributed to their National Metering Identifier (NMI). This value would remain unchanged other than for a significant change in connection arrangements.

Capacity and actual demand charges

Shared network costs for ICCs, CACs, SAC Large customers and some SAC Small customers are recovered through the capacity charge and/or actual demand charge components. These charges provide economic signals to the customers on the existing and future use of the shared network on the basis that customers who place greater pressure on the system incur higher charges. Each of these charges is discussed further below.
LRMC/peak charge components

Setting the level and structure of the peak charge component under demand-based tariffs is important in terms of establishing pricing mechanisms that reflect the LRMC of supply and are effective in providing a price signal to customers to reduce demand in peak network congestion periods. Setting the peak charge based on the LRMC encourages customers to invest in demand management technologies or change their behaviour only to the extent that it is cheaper (or more valuable to the customer) than the cost to Ergon Energy of increasing network capacity.

The peak demand components in the suite of STOUD tariffs were designed based on considering alternative mechanisms for charging demand in the peak and shoulder periods. The mechanisms chosen are considered to be both cost reflective of the LRMC of the cost of supplying electricity and effective in enabling customers to respond to price signals.

The peak demand charges proposed in the tariffs are based on a transitional approach to signalling LRMC. We took into account customer concerns and impacts as well as the level of uncertainty and volatility in the LRMC value when determining the peak charge to apply.

Residual/Off-peak charge components

Regulated revenue not recovered through the LRMC-related charge should be recovered in a manner that has as little influence as possible on patterns of electricity demand. We considered a number of choices as options to recover residual costs.

These include:

- fixed charges ($/day)
- off-peak or any time energy charges ($/kWh)
- off-peak network demand with or without a minimum chargeable demand ($/kW capacity).

The combinations proposed across the various user groups have been selected on efficiency and effectiveness, as well as ability of customers to respond.

Demand charges are also utilised in the legacy tariffs available to ICCs, CACs, and SAC Large customers. These charges are discussed further below.

Capacity charges

The capacity charge applies to ICC and CAC network users only.

The demand used for the calculation of the capacity charge is the authorised demand or, if there is no authorised demand, the annual maximum demand in the previous full pricing period prior to the setting of prices. Under certain circumstances, where there has been a significant change in demand attributable to a network user’s load change after this previous pricing period, a more recent demand may be substituted.

Where the actual demand exceeds the authorised demand in any one month, the actual demand will be substituted for the authorised demand in the calculation of the capacity charge for that month.
For the CAC STOUD tariffs, the capacity charge applies for all 12 months of the year. However, over the summer months, it excludes demand occurring during the peak demand window of 10.00 am to 8.00 pm on summer weekdays.

**Actual demand charges**

Actual demand charges apply to all ICC, CAC and SAC Large customers and also to the SAC Small STOUD tariffs (Business and Residential).

For ICCs and CACs, the demand is measured in kVA. For SAC Large, the demand is measured in kW. Further, the actual demand charge is applied to the customer’s actual demand above a set threshold, which varies depending on the type of tariff (e.g. 400 kW for Demand Large tariffs).

For the legacy tariffs, the actual monthly demand is based on the highest individual demand in any single half hour in the month.

In the LRMC-based STOUD tariffs, actual demand charges link to both peak and off-peak charging parameters. The peak demand charge only relates to demand during the peak periods in each month of the summer season:

- For SAC Small, the monthly demand charges, for both summer and non-summer, are based on an average of the demand the customer places on the network in the daily demand window. For business customers, the daily demand window is from 10.00 am to 8.00 pm on weekdays. For residential customers, the window is from 3.00 pm to 9.30 pm every day of the week.

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

  In the non-summer months the rate applied to the demand charge is much lower. A 3 kW floor also applies (non-summer months only) – meaning 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.

- For SAC Large, the summer peak demand charge is based on the monthly maximum demand recorded in any single half hour between 10.00 am and 8.00 pm on a summer weekday. This monthly demand charge is applied to the kW amount by which this monthly maximum demand exceeds 20 kW.

  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). Where the monthly metered maximum demand is less than the demand threshold, the chargeable demand for that month is set to zero.

- For CACs, the peak demand charge is based on the customer’s monthly maximum kVA demand during the peak period in each summer month (i.e. 10.00 am to 8.00 pm on a summer weekday).

**Excess reactive power (kVar) charges**

This charge applies to ICC and CAC network users. It reinforces the kVA price signal to customers operating at non-compliant power factors, encouraging these customers to
improve their power factor to a compliant level and reduce their network capacity usage. The excess reactive (kVAr) power charge is calculated monthly based on the kVAr level 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 customer’s compliant power factor), excess kVAr charges are applied.

**Volume charges**

The volume charge in part recovers costs that have been allocated on a postage stamped basis. For SAC Small, the volume charge also recovers a portion of the shared network costs not included in the fixed charge.

In the LRMC tariffs, the volume charge contributes to the recovery of residual revenue.

The volume charge applies to the energy (kWh) metered at the customer’s installation and may be based on a flat rate, an inclining block or time-of-use (TOU) charging structure (depending on the applicable network tariff).

**Step C6: Designated pricing proposal charges to network tariffs**

**ICCs**

TUOS tariffs are customer specific and incorporate:

- a fixed charge ($/day)
- a capacity charge ($/kVA of authorised demand/month)
- a common services and general charge ($/day)
- a volume charge ($/kWh).

Where the actual demand exceeds the authorised demand in any one month, the actual demand will be substituted for the authorised demand in the calculation of the capacity charge billed for that month.

To determine the total TUOS volume charge, the metered consumption must be multiplied by the customer’s Distribution Loss Factor (DLF) and then applied to the TUOS volume rate ($/kWh).

**CACs**

TUOS tariffs are averaged at the TCP after the allocation of costs to ICCs and incorporate:

- a fixed charge ($/day)
- a capacity charge ($/kVA of authorised demand/month)
- a volume charge ($/kWh).

Ergon Energy combines rates in geographical regions in the East and West Zones and passes through TUOS charges to CACs in these zones, thus providing an appropriate locational signal in each region.
Where the actual demand exceeds the authorised demand in any one month, the actual demand will be substituted for the authorised demand in the calculation of the capacity charge billed for that month.

To determine the total TUOS volume charge, the metered consumption must be multiplied by the customer’s DLF and then applied to the TUOS volume rate ($/kWh).

**SAC Large**

As is done for CACs, TUOS tariffs for this group are averaged at the TCP after the allocation of costs to ICCs and CACs and incorporate:

- a fixed charge ($/day)
- a demand charge ($/kW/month)\(^{18}\)
- a volume charge ($/kWh).

Ergon Energy combines rates in geographical regions in the East and West Zones and passes through TUOS charges to SAC Large customers in these zones, thus providing an appropriate locational signal in each region.

To determine the total TUOS volume charge, the metered consumption must be multiplied by the customer’s DLF and then applied to the TUOS volume rate ($/kWh).

The same SAC Large DUOS demand threshold calculation mechanism applies for TUOS charges. Where the monthly metered maximum demand is less than the demand threshold, the chargeable demand is set to zero and no demand charge is payable for that month.

**SAC Small**

TUOS tariffs for this category are an average of the remaining TUOS costs to be collected from the sum of all TCPs and incorporate:

- a fixed charge ($/day)
- a volume charge ($/kWh).

To determine the total TUOS volume charge, the metered consumption must be multiplied by the customer’s DLF and then applied to the TUOS volume rate ($/kWh).

A fixed charge does not apply to unmetered supplies or controlled load tariffs.

**EGs**

For those EGs that only generate into the distribution system TUOS tariffs for generated energy do not apply.

For those EGs that generate into as well as take load from the distribution system:

- TUOS tariffs for generated energy do not apply
- TUOS tariffs for load taken from the distribution system will be allocated as per the appropriate network user group (i.e. ICC, CAC or SAC).

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\(^{18}\) For SAC Large STOUD tariffs, this demand charge has two components – peak and off-peak. The same rate applies to each component.
To determine the total TUOS volume charge, the metered consumption must be multiplied by the customer’s DLF and then applied to the TUOS volume rate ($/kWh).

**Step D6: Allocation of jurisdictional scheme amounts into network tariffs**

Jurisdictional scheme amounts will be recovered from network users as follows:

- Jurisdictional scheme amounts are allocated to tariff classes using a process similar to that used to allocate overhead costs in the DCOS model.
- The total revenue requirement for each tariff class is then converted to tariffs made up of:
  - fixed charge ($/day) for ICCs
  - fixed charge ($/day) and a volume charge ($/kWh) for SACs and CACs.

Jurisdictional scheme charges apply to all network tariffs, except unmetered supply and EGs.

As noted in Step D2, from 1 July 2017 Ergon Energy’s jurisdictional scheme rates will be set to zero in all our network tariffs. This is because Ergon Energy received a direction from Queensland Government not to pass on AER-approved jurisdictional scheme charges.

### 3.4 Assigning and reassigning customers to tariffs and tariff classes

Appendix D of our TSS provides information on how customers are assigned or reassigned to tariffs and tariff classes for Standard Control Services, and the process retailers should follow if they do not agree with an assignment or reassignment decision we made.

Our *Network Tariff Guide* also details the application rules and tariff conditions for each of our network tariffs that customers are able to be assigned or reassigned to.

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A fixed charge does not apply to controlled load tariffs.
4. Distribution Loss Factors

4.1 Overview

Distribution loss factors (DLFs) are calculated annually by Ergon Energy in accordance with requirements of the NER in order to determine the amount of energy dispatched to supply customers. They are approved by the AER and published by the Australian Energy Market Operator (AEMO) on their website.

Every NMI has a DLF code which is associated with the location of the metering point.

The DLF is a multiplier used to convert the actual metered energy into the equivalent energy passing through the appropriate TCP by allowing for the distribution network losses that are incurred between the meter and the TCP.

The DLF is applied to the metered consumption for the calculation of TUOS volume charges. DLFs are generally assigned on the basis of the standard metering voltage for the type of connection. However, a specific DLF may be applied where there is a unique network supply configuration.

4.2 Further information

Our *Network Tariff Guide* outlines the DLF categories used by Ergon Energy and their application rules. The *Network Tariff Guide* also includes the standard DLFs that have been approved to apply to our SAC network tariffs for 2019-20. This document is available on our website:


Further information on Ergon Energy’s methodology for calculating DLFs is available on our website:


Detailed information about the purpose and application of DLFs may also be obtained from the AEMO website:

5. **EG Avoided TUOS payments**

5.1 **Overview**

“Avoided TUOS” applies where Ergon Energy does not source load from Powerlink’s transmission system because part of the load is supplied from EGs that are connected directly to our distribution system.

In certain situations the NER requires Ergon Energy to make payments to EGs, where that payment represent a reduction in the amount payable by Ergon Energy to Powerlink.

In particular, clause 5.5(h) of the NER requires DNSPs to calculate "avoided charges for the locational component of prescribed TUOS services", and clause 5.5(i) requires DNSPs to calculate the amount to be passed through to an EG. This is done by determining:

1. the charges for the locational component of prescribed TUOS services that would have been payable by the DNSP for the relevant financial year “if the EG had not injected any energy at its connection point during that financial year”\(^{20}\)
2. “the amount by which the charges calculated in subparagraph (1) exceed the amount for the locational component of prescribed TUOS services actually payable by the DNSP, which amount will be the relevant amount for the purposes of paragraph (h) [clause 5.5(h)]”\(^{21}\)

The underlying concept is that, where Ergon Energy derives a benefit from the existence of an EG (the benefit being a reduction in the locational component of prescribed TUOS payments to Powerlink), it should pass that benefit through to the EG.

5.2 **Eligibility for Avoided TUOS payments**

Consistent with NER requirements, we will make Avoided TUOS payments to EGs that have:

- sought access to Ergon Energy’s distribution network under Chapter 5 of the NER; and
- a generator Connection Agreement with Ergon Energy; and
- registered or intend to register with AEMO as a Generator Rules Participant.\(^{22}\)

If an exemption applies, or there is no intention for the EG to register as a Generator Rules Participant, we will not make Avoided TUOS payments.

In specific circumstances, Avoided TUOS payments may be allowed to be received by another entity other than the EG (for example where an intermediary is appointed and registered as a Generator under the NER).

---

\(^{20}\) Clause 5.5(i) (1) (i) of the NER.

\(^{21}\) Clause 5.5(i) (2) of the NER.

\(^{22}\) Some embedded generating units are required to register as a Generator Rules Participant under the NER.
5.3 Methodology

5.3.3 Key concepts and principles

Locational component of prescribed TUOS

As noted in Section 3, Powerlink charges Ergon Energy prescribed TUOS at the TCP level. These charges have both a locational and non-locational component, with the locational component reflected through the Capped Customer TUOS Usage Price – specifically, the $/kW/month of average demand component, which Ergon Energy converts into a $/kWh charge.

Reverse flow and net load

Where electricity produced by the generator flows back into the transmission network at the TCP, this is known as excess export, or reverse flow. Where there is reverse flow at the TCP level, that generation does not reduce our net load downstream of that TCP. Accordingly, we remove the reverse flowing electricity from the calculations of Avoided TUOS. This means, our calculation of Avoided TUOS for a particular EG will be based on the difference between:

1. The actual net load at the TCP (and the relevant locational component of prescribed TUOS charges); and
2. The net load at the TCP if the EG was not there (and the relevant locational component of prescribed TUOS charges).

Impact on Avoided TUOS where multiple generators are exporting

In the event that multiple EGs are connected to the same TCP, and there is reverse flow through the TCP, Ergon Energy will apportion the reverse flow attributable to each EG in line with the proportion of each EG’s generation into the distribution network. For example, if Generator A exports 100 MWh in a month and Generator B exports 200 MWh in a month, and there is 30 MWh of excess export/reverse flow into the transmission network in that month, we will attribute 10 MWh to Generator A (100/300 x 30 = 10) and 20 MWh to Generator B (200/300 x 30 = 20).

5.3.4 Avoided TUOS calculation

We use the below methodology to comply with the NER:

1. determine the amount of energy sent out by the EG in the relevant financial year (kWh)
2. convert this to an equivalent amount of energy at the TCP, by adjusting the export energy by the DLF of the EG
3. determine the net generator output (i.e. the generator output that is utilised by the local distribution network, by subtracting the actual metered energy that flows back into the transmission network at the TCP). Where multiple generators are operating in the same local area, we will apportion the reverse flow to each EG using the principles outlined in Section 5.3.3 above.
4. add the net generation output to the TCP actual metered data for the financial year
5. determine the TUOS that would have been charged if the generator was not connected, by recalculating the customer TUOS usage charges (demand and energy)
6. subtract the actual TUOS payment from the amount calculated in step 5
7. arrange payment of the resultant value from step 6 to the EG (or intermediary).

5.3.5 Payment of Avoided TUOS

Avoided TUOS payments to EGs following the end of the relevant financial year will be made as agreed between Ergon Energy and the particular EG (or intermediary) and may be:

- a lump sum payment by cheque
- a lump sum credit against future Network Charges accounts
- staged payments or credits over a future period.

5.4 Recovery of Avoided TUOS

Costs related to payments to EGs for Avoided TUOS charges are not part of our revenue cap. Under the NER, we are able to recover costs associated with Avoided TUOS through TUOS charges in our network tariffs. Further detail on the TUOS recovery process is set out in Section 3 of this document.
Appendix 1: Additional pricing information

Pricing principles philosophy

Ergon Energy’s tariff setting objective is to ensure that the revenue cap is fully recovered from network users in a manner that is:

- economically efficient
- equitable
- provides price stability
- transparent
- practical
- easily understood.

The distribution network pricing methodology has been developed to meet the objectives by adopting the following pricing principles:

Network tariffs should recover no more than the allowable regulated revenue cap from the forecast customer base in any one year.

The recovery of the revenue cap is achieved through the allocation of costs to tariff classes such that the resulting revenue from the application of network tariffs equals no more than the revenue cap.

Network tariffs should be determined using a well-defined and clearly explained methodology.

The purpose of this Information Guide is to define and explain the methodology that we use to establish network tariffs.

Network tariff development should incorporate an analysis of the cost of service provision that includes:

- definition of the network user classes to which distribution services are provided
- segregation of network costs by voltage level and location
- allocation of the network costs to network user classes and voltage levels
- translation of allocated costs into service prices.

We conduct an analysis of our network user and cost base to establish tariff classes and network tariffs that are an equitable reflection of the network users’ use of the existing network and specific dedicated assets, while minimising the inefficiency of price averaging.

Network tariffs should signal the economic costs of service provision and promote the efficient use of the network, by:

- being subsidy free (i.e. between avoidable cost of supply and stand alone cost of supply)
- having regard to the level of available service capacity
- signalling the impact of additional usage on existing and future investment costs.
Network tariffs for the different tariff classes are designed, within the constraints imposed by the type of metering, to provide signals to the network users on the impact of existing and future network capacity and costs.

Provided that economic costs are recovered, network tariffs should **be responsive to the requirements and circumstances of network users** by:

- being a fair and equitable distribution of costs  
- being perceived by network users as an equitable reflection of the network users' utilisation of the network assets  
- discouraging uneconomic bypass of the distribution network  
- allowing for negotiation, where appropriate, to better reflect the economic value of specific services.

Network tariffs reflect the standard level of electricity supply in terms of assets used, quality, reliability and security available to network users at their point of connection to the network.

**Information** should be **disclosed** on tariff classes, network tariff levels and structures, underlying costs, price derivation methods and rationale, and medium term price paths to ensure:

- current and potential network users are able to understand the basis for prices and take account of network tariffs in their consumption, investment and location decisions  
- interested parties are able to better assess the range of economic opportunities for meeting network user requirements that may reduce network users’ costs and lead to more efficient outcomes.

This Information Guide, and our other network pricing documentation, provides sufficient information on the methodology that we use to establish network tariffs to be transparent to network users.

Development of network tariffs should ensure **maintenance of price stability** and **certainty**.

It is intended that there is transparency of future network tariffs for network users to make informed investment decisions. In restructuring our network tariffs, we seek to balance the rate of the structural change with individual customer cost impacts. The inevitable change associated with the development of network tariffs is managed by:

- on-going customer and stakeholder consultation  
- transparency and communication of future structural change intentions, including through our TSS  
- placing constraints on annual individual customer network tariff increases.

Underlying service classifications, cost data, cost allocations and other elements that contribute to pricing decisions should be **periodically reviewed and updated** where relevant to reflect industry developments and changes in network user requirements, expectations and preferences, methods of service provision and costs.
We commenced a detailed review of our Network Tariff Strategy in 2012. This was in response to a major shift in the way our customers use the electricity network, together with changes to the NER. Our network, which has been invested in heavily to respond to the growth in demand during peak times (which can occur for only a few days a year), is now not being utilised as fully as it could be outside of peak times. To respond to this, and other considerations, we have been restructuring our network tariffs. The first changes occurred in 2014–15; with further changes being progressed each year.

Our TSS provides details of expected tariff development out to 30 June 2020 and the rationale for the tariffs, as well as details of the stakeholder consultation undertaken, the development process and implementation plans. Further information on our future network tariff structure reform into our next Regulatory Control Period 2020-2025 is available through this link: www.talkingenergy.com.au.

### The economic signals present in the structure of TUOS charges should be preserved

When allocating transmission charges to distribution customers – to enable customers to interpret, and respond to, those economic signals.

TUOS charges are calculated and levied by Powerlink to Ergon Energy. Within the constraints of metering type and/or network price, the economic signals inherent in the transmission price structure are passed directly through to the customers to the maximum extent possible given the practical constraint of using average prices for groups of similar customers.

Since our customers are supplied across a geographically diverse transmission system, the transmission prices vary markedly between TCPs. For this reason, we separate the DUOS charges and TUOS charges into discrete components enabling customers to identify the contribution of the transmission charges to their overall use of network costs.

### Cost allocators for Network Use of System services

There are a range of cost allocators that can be used in the DCOS model adopted by Ergon Energy. The selection of the appropriate allocator is based on the ability of that allocator to reflect the relationship between various costs and what causes those costs to occur. The range of possible allocators includes:

- number of customers
- any time energy
- period energy (TOU)
- ATMD
- period demand (TOU)
- coincident demand
- replacement cost of assets.

The customer numbers and usage are identified for each zone from an interrogation of the customer information system based on the customer’s geographic location. The replacement cost values of the assets for each zone are determined using the Depreciated Replacement Cost of assets and the corresponding remaining life from the Regulatory Asset Base in the Distribution Determination.
Ergon Energy has adopted the following allocators in the DCOS model:

- number of customers
- any time energy
- ATMD
- replacement cost of assets.

The reasoning behind the selection of these allocators is as follows:

- **Number of customers.** This allocator is appropriate for those costs that are dependent upon or driven by the number of connected customers. We have a number of costs that are customer number based, including a significant proportion of the overhead costs of the business that are driven by the number of staff and systems required to serve the customer base.

- **Any time energy.** This is used to allocate those costs that are related to the size of the customer but not specifically to the demand that customer places on the network (e.g. network operating costs). In addition, consistent with the recovery mechanisms used in the electricity market, costs that cannot be directly related to a product or service are recovered through the use of any time energy prices (e.g. some overhead costs). A portion of TUOS is also allocated to customers on an any time energy basis for those energy related TUOS charge components billed to Ergon Energy by the Transmission Network Service Provider (i.e. Powerlink) so as to retain the transmission pricing signals in customer tariffs.

- **ATMD.** This method of allocation is used for the shared system costs. The basis for this is that network development in each part of the network is driven by peak demand in that part of the network. For example, in a domestic area, the shared network capacity is based on the peak domestic demand that generally occurs for Ergon Energy in the late afternoon and early evening during the summer. By contrast, in commercial/industrial areas, the shared network capacity is generally determined by summer working day peak demands.

  These individual demands throughout the network combine to form an overall coincident system peak demand. However, the coincident demand is more relevant to transmission network capacity than distribution. While the ideal cost allocation mechanism would be based on a real time model which constantly monitors the network demands at specific locations, such an approach is not achievable at present and ATMD provides a simple and reasonable basis for apportioning system usage related costs. It reflects the fact that demand is the primary driver of shared network costs. A portion of TUOS is also allocated to network users on an ATMD basis for the demand-related TUOS charge components applied to Ergon Energy by the TNSP so as, once again, to retain the transmission pricing signals in network user prices.

- **Replacement cost of assets.** The replacement costs of the assets are used as allocators to apportion ROA, depreciation and opex costs across the various cost categories. The replacement costs are not used directly to calculate the value of any of the costs within the price allocation model.

  The replacement costs are used to allocate the ROA, depreciation and opex costs because the replacement costs are relatively stable over time, whereas the depreciated values change. If the depreciated values were used, the network user prices would vary up and down depending on when old assets were replaced with new assets. The actual
age and value of the assets used to supply a network user is not relevant to the prices charged for that network user because we are required to maintain supply to the network user in accordance with statutory and NER requirements, irrespective of the type or age of assets deployed.

An example of replacement costs used in the allocation of opex is shown below.

<table>
<thead>
<tr>
<th>Opex allocation for voltage level = Total opex $ allowance x RC of assets for voltage level</th>
<th>RC of total assets</th>
</tr>
</thead>
<tbody>
<tr>
<td>Where RC = replacement cost</td>
<td></td>
</tr>
</tbody>
</table>

Revenue cost components to DCOS cost categories

The DCOS cost categories are the categories used in Ergon Energy’s pricing model to allocate the allowable costs to the various customer classes. Table A1.1 shows how the allowable ARR, TUOS and jurisdictional scheme cost components are divided into the various cost groups for further allocation to the DCOS cost categories.

Table A1.1: Revenue cost components to DCOS cost categories

<table>
<thead>
<tr>
<th>Revenue cost components</th>
<th>Cost groups</th>
<th>DCOS cost categories</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>DUOS charges</td>
</tr>
<tr>
<td></td>
<td></td>
<td>System opex</td>
</tr>
<tr>
<td>Opex</td>
<td>Network Operating</td>
<td>✓</td>
</tr>
<tr>
<td></td>
<td>Network Maintenance</td>
<td>✓</td>
</tr>
<tr>
<td></td>
<td>Other Asset Operating</td>
<td>✓</td>
</tr>
<tr>
<td>ROA</td>
<td>Network Operation Assets</td>
<td>✓</td>
</tr>
<tr>
<td></td>
<td>Network Distribution Assets</td>
<td>✓</td>
</tr>
<tr>
<td></td>
<td>Other Assets</td>
<td>✓</td>
</tr>
<tr>
<td>Depreciation</td>
<td>Network Operation Assets</td>
<td>✓</td>
</tr>
<tr>
<td></td>
<td>Network Distribution Assets</td>
<td>✓</td>
</tr>
<tr>
<td></td>
<td>Other Assets</td>
<td>✓</td>
</tr>
<tr>
<td>TUOS</td>
<td>TUOS charges</td>
<td>✓</td>
</tr>
<tr>
<td>Jurisdictional scheme</td>
<td>Jurisdictional scheme charges</td>
<td>✓</td>
</tr>
</tbody>
</table>
Allocating revenue to DUOS network tariffs

In 2014–15, we started a process of rebalancing and restructuring our network tariffs. This has changed the approach to determining rates for individual tariff parameters to facilitate greater alignment with the LRMC.

In the case of existing tariff structures, this involved rebalancing the weighting of parameters to initially focus on the adjustment of demand charges towards alignment with LRMC. These adjustments were small and were undertaken within constraints related to maximum levels of impact on individual connections.

The rebalancing and restructuring process has continued in 2019-20. All optional tariffs adopt the LRMC approach.

Conversion of Powerlink cost categories to TUOS prices

Table A1.2 shows the allocation of the Powerlink price components to the customer price component for TUOS recovery.

Table A1.2: Conversion of Powerlink cost categories to TUOS prices

<table>
<thead>
<tr>
<th>Powerlink cost category</th>
<th>TUOS network price components</th>
<th>Ergon Energy charge structure</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Entry/exit connection price ($/day)</td>
<td>Capped customer TUOS usage prices</td>
</tr>
<tr>
<td></td>
<td>Usage capacity price</td>
<td>Demand component ($/kW)</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Fixed charge ($/day)</td>
<td>ICC</td>
<td>✓</td>
</tr>
<tr>
<td></td>
<td>CAC</td>
<td>✓</td>
</tr>
<tr>
<td></td>
<td>SAC Large</td>
<td>✓</td>
</tr>
<tr>
<td></td>
<td>SAC Small ^a</td>
<td>✓</td>
</tr>
<tr>
<td>Capacity / Actual Demand charge ($/kW/month or $/kVA/month)</td>
<td>ICC</td>
<td>✓</td>
</tr>
<tr>
<td></td>
<td>CAC</td>
<td>✓</td>
</tr>
<tr>
<td></td>
<td>SAC Large</td>
<td>✓</td>
</tr>
<tr>
<td></td>
<td>SAC Small</td>
<td></td>
</tr>
<tr>
<td>Common services and general charge ($/day)</td>
<td>ICC</td>
<td>✓</td>
</tr>
<tr>
<td></td>
<td>CAC</td>
<td></td>
</tr>
<tr>
<td></td>
<td>SAC Large</td>
<td></td>
</tr>
<tr>
<td></td>
<td>SAC Small</td>
<td></td>
</tr>
<tr>
<td>Volume charge ($/kWh)</td>
<td>ICC</td>
<td>✓</td>
</tr>
<tr>
<td></td>
<td>CAC</td>
<td>✓</td>
</tr>
<tr>
<td></td>
<td>SAC Large</td>
<td>✓</td>
</tr>
<tr>
<td></td>
<td>SAC Small</td>
<td>✓</td>
</tr>
</tbody>
</table>

Notes:

a) A fixed charge does not apply to Volume Night Controlled, Volume Controlled and Unmetered Supply network tariffs.
Price components for network users

Table A1.3 shows which price components are applicable to each customer group.

Table A1.3: Network price components

<table>
<thead>
<tr>
<th>Network price component</th>
<th>Description</th>
<th>Customer groups to which network price component is applicable</th>
</tr>
</thead>
<tbody>
<tr>
<td>Fixed charge ($/day)</td>
<td>DUOS: Reflective of the costs associated with the connection assets (entry and exit services) and network user management services.</td>
<td>ICC, CAC, SAC Large, SAC Small, Volume Controlled, Volume Night Controlled, Unmetered (incl. public lighting), EG (Generation only)</td>
</tr>
<tr>
<td></td>
<td>TUOS: A portion of the allocated TUOS costs.</td>
<td>ICC, CAC, SAC Large, SAC Small, Volume Controlled, Volume Night Controlled, Unmetered (incl. public lighting), EG (Generation only)</td>
</tr>
<tr>
<td></td>
<td>Jurisdictional scheme: A portion of the allocated jurisdictional scheme amount.</td>
<td>ICC, CAC, SAC Large, SAC Small, Volume Controlled, Volume Night Controlled, Unmetered (incl. public lighting), EG (Generation only)</td>
</tr>
<tr>
<td>Connection unit charge</td>
<td>DUOS only: Reflective of the costs associated with the connection assets not otherwise paid for upfront.</td>
<td>ICC, CAC, SAC Large, SAC Small, Volume Controlled, Volume Night Controlled, Unmetered (incl. public lighting), EG (Generation only)</td>
</tr>
<tr>
<td>($/connection unit/day)</td>
<td>Capacity charge ($/kVA/month) DUOS: Reflective of the network capacity required by the network user on a long term basis and levied on the basis of an AD.</td>
<td>ICC, CAC, SAC Large, SAC Small, Volume Controlled, Volume Night Controlled, Unmetered (incl. public lighting), EG (Generation only)</td>
</tr>
<tr>
<td></td>
<td>TUOS: A portion of the allocated TUOS costs.</td>
<td>ICC, CAC, SAC Large, SAC Small, Volume Controlled, Volume Night Controlled, Unmetered (incl. public lighting), EG (Generation only)</td>
</tr>
<tr>
<td>Excess reactive power</td>
<td>DUOS: Reflective of the impact on network capacity at peak monthly demand.</td>
<td>ICC, CAC, SAC Large, SAC Small, Volume Controlled, Volume Night Controlled, Unmetered (incl. public lighting), EG (Generation only)</td>
</tr>
<tr>
<td>charge ($/kVAR/month)</td>
<td>Common service and general charge ($/day) TUOS only: A portion of the allocated TUOS costs.</td>
<td>ICC, CAC, SAC Large, SAC Small, Volume Controlled, Volume Night Controlled, Unmetered (incl. public lighting), EG (Generation only)</td>
</tr>
<tr>
<td>Actual demand charge</td>
<td>DUOS: Reflective of the costs of network capacity availability and limitations.</td>
<td>ICC, CAC, SAC Large, SAC Small, Volume Controlled, Volume Night Controlled, Unmetered (incl. public lighting), EG (Generation only)</td>
</tr>
<tr>
<td>($/kW/month or $/kVA/month)</td>
<td>TUOS: A portion of the allocated TUOS costs.</td>
<td>ICC, CAC, SAC Large, SAC Small, Volume Controlled, Volume Night Controlled, Unmetered (incl. public lighting), EG (Generation only)</td>
</tr>
<tr>
<td>Volume charge ($/kWh)</td>
<td>DUOS: Recovery of costs not directly allocated or associated with network drivers, through a non-distortionary basis. The charge also includes costs that are proportional to the size of the customer, such as customer management.</td>
<td>ICC, CAC, SAC Large, SAC Small, Volume Controlled, Volume Night Controlled, Unmetered (incl. public lighting), EG (Generation only)</td>
</tr>
</tbody>
</table>
## Network price component

<table>
<thead>
<tr>
<th>Description</th>
<th>Customer groups to which network price component is applicable</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>TUOS</strong></td>
<td>ICC</td>
</tr>
<tr>
<td>For ICCs, CACs and SAC Large, a portion of the allocated TUOS costs and for SAC Small, the remaining portion of allocated TUOS costs.</td>
<td>✓</td>
</tr>
<tr>
<td><strong>Jurisdictional schemes</strong></td>
<td>Jurisdictional schemes</td>
</tr>
</tbody>
</table>

### Notes:

a) There is no fixed charge for CAC and SAC Small STOUD tariffs. A 3 kW off-peak minimum chargeable demand applies to the SAC Small STOUD tariffs in the non-summer months.

b) The fixed charge for unmetered supply tariffs is $/day/device.

c) For SAC Small, actual demand charges apply to STOUD tariffs only.

d) For SAC Large STOUD tariffs, the actual demand charges have peak and off-peak components. The same rate applies to each component.
## Glossary

### Abbreviations

<table>
<thead>
<tr>
<th>Abbreviation</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>AEMO</td>
<td>Australian Energy Market Operator</td>
</tr>
<tr>
<td>AER</td>
<td>Australian Energy Regulator</td>
</tr>
<tr>
<td>ARR</td>
<td>Annual Revenue Requirement</td>
</tr>
<tr>
<td>AS</td>
<td>Australian Standard</td>
</tr>
<tr>
<td>ATMD</td>
<td>Any Time Maximum Demand</td>
</tr>
<tr>
<td>CAC</td>
<td>Connection Asset Customer</td>
</tr>
<tr>
<td>DCOS</td>
<td>Distribution Cost of Supply</td>
</tr>
<tr>
<td>DLF</td>
<td>Distribution Loss Factor</td>
</tr>
<tr>
<td>DNSP</td>
<td>Distribution Network Service Provider</td>
</tr>
<tr>
<td>DUOS</td>
<td>Distribution Use of System</td>
</tr>
<tr>
<td>EDNC</td>
<td>Electricity Distribution Network Code</td>
</tr>
<tr>
<td>EG</td>
<td>Embedded Generator</td>
</tr>
<tr>
<td>Energex</td>
<td>Energex Limited</td>
</tr>
<tr>
<td>Ergon Energy</td>
<td>Ergon Energy Corporation Limited</td>
</tr>
<tr>
<td>Excess kVAr</td>
<td>Excess reactive power charge</td>
</tr>
<tr>
<td>FIT</td>
<td>Feed-in tariff</td>
</tr>
<tr>
<td>GWh</td>
<td>Gigawatt hour</td>
</tr>
<tr>
<td>ICC</td>
<td>Individually Calculated Customer</td>
</tr>
<tr>
<td>kV</td>
<td>Kilovolt</td>
</tr>
<tr>
<td>kVA</td>
<td>Kilovolt-ampere</td>
</tr>
<tr>
<td>kVAr</td>
<td>Kilovolt-ampere reactive</td>
</tr>
<tr>
<td>kW</td>
<td>Kilowatt</td>
</tr>
<tr>
<td>kWh</td>
<td>Kilowatt hour</td>
</tr>
<tr>
<td>Law</td>
<td>National Electricity Law</td>
</tr>
<tr>
<td>LED</td>
<td>Light emitting diode</td>
</tr>
<tr>
<td>LGA</td>
<td>Local government area</td>
</tr>
<tr>
<td>LRMC</td>
<td>Long Run Marginal Cost</td>
</tr>
<tr>
<td>LV</td>
<td>Low voltage</td>
</tr>
<tr>
<td>MWh</td>
<td>Megawatt hour</td>
</tr>
<tr>
<td>NEM</td>
<td>National Electricity Market</td>
</tr>
<tr>
<td>NER</td>
<td>National Electricity Rules</td>
</tr>
<tr>
<td>NMI</td>
<td>National Metering Identifier</td>
</tr>
<tr>
<td>Opex</td>
<td>Operating expenditure</td>
</tr>
<tr>
<td>p.a.</td>
<td>Per annum</td>
</tr>
<tr>
<td>PTRM</td>
<td>Post Tax Revenue Model</td>
</tr>
<tr>
<td>PV</td>
<td>Photovoltaic</td>
</tr>
<tr>
<td>ROA</td>
<td>Return on assets</td>
</tr>
<tr>
<td>SAC</td>
<td>Standard Asset Customer</td>
</tr>
<tr>
<td><strong>SCS</strong></td>
<td>Standard Control Services</td>
</tr>
<tr>
<td><strong>STOUD</strong></td>
<td>Seasonal Time-of-Use Demand</td>
</tr>
<tr>
<td><strong>STOUE</strong></td>
<td>Seasonal Time-of-Use Energy</td>
</tr>
<tr>
<td><strong>STPIS</strong></td>
<td>Service Target Performance Incentive Scheme</td>
</tr>
<tr>
<td><strong>TCP</strong></td>
<td>Transmission Connection Point&lt;sup&gt;23&lt;/sup&gt;</td>
</tr>
<tr>
<td><strong>TNSP</strong></td>
<td>Transmission Network Service Provider</td>
</tr>
<tr>
<td><strong>TOU</strong></td>
<td>Time-of-Use</td>
</tr>
<tr>
<td><strong>TSS</strong></td>
<td>Tariff Structure Statement</td>
</tr>
<tr>
<td><strong>TUOS</strong></td>
<td>Transmission Use of System</td>
</tr>
</tbody>
</table>

### Definitions

**Actual demand charge**

A type of charge (charging parameter) included in Ergon Energy’s network tariff structures to signal the effect demand has on the shared network and system augmentation. The demand used in the calculation of the charge is the maximum demand recorded in any half hour period each month.

**Alternative Control Service**

A distribution service provided by Ergon Energy that the AER has classified as an Alternative Control Service under the NER. Includes fee based services, quoted services, Default Metering Services and Public Lighting Services.

**Annual revenue adjustment**

Annual adjustments made to Ergon Energy’s smoothed revenue requirement for Standard Control Services for matters such as out-turn inflation, the return on debt, STPIS, pass throughs, and the difference between forecast and actual revenue received for DUOS charges.

**Annual Revenue Requirement (ARR)**

The revenue determined by the applicable PTRM.

**Any time energy**

Is the amount of energy consumed by the customer irrespective of the time of day.

**Any Time Maximum Demand (ATMD)**

Is the maximum half hourly demand for a customer that occurs at any time within a specified period.

**Australian Energy Regulator (AER)**

The AER is an independent statutory authority that is part of the Australian Competition and Consumer Commission. The AER is responsible for the economic regulation of electricity networks in the National Electricity Market (NEM). It also monitors the wholesale electricity and gas markets and is responsible for compliance with and enforcement of the Law, NER, National Gas Law and Rules, and the National Energy Retail Law and Rules.

**Authorised demand**

The maximum demand permitted to be imported or exported to the network by a network user, based on the nature of their connection. The authorised demand is either:

- negotiated with the network user and detailed in their connection contract
- determined by Ergon Energy as part of the annual price setting process, using historical data.

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<sup>23</sup> Also referred to as a ‘Transmission Network Connection Point’.
<p>| <strong>Avoided TUOS</strong> | The amount paid to an eligible EG for the locational component of prescribed TUOS services that would have been payable by Ergon Energy to a TNSP had the EG not been connected to the distribution network. The methodology Ergon Energy uses to comply with the NER is set out in this document. |
| <strong>Business customer</strong> | Means a customer who is not a residential customer (as defined in the Queensland Electricity Distribution Network Code (EDNC)). |
| <strong>Capacity charge</strong> | A type of charge (charging parameter) included in Ergon Energy’s network tariff structures. The capacity charge is reflective of the costs associated with the network capacity required by a customer on a long term basis. |
| <strong>Capital contribution</strong> | A capital contribution is a prepayment for the provision of Direct Control Services. A capital contribution may be charged to a customer if the new connection or modification for an existing connection is required to the network to accommodate the connection/modification. Ergon Energy’s Connection Policy sets out circumstances in which a capital contribution may be required and details how the capital contribution to be charged to a customer is calculated. |
| <strong>Charging parameter</strong> | The constituent elements of a tariff (as defined in the NER). |
| <strong>Connection</strong> | The physical link to or through a transmission network or distribution network. |
| <strong>Connection Asset Customer (CAC)</strong> | Refer to Table 3.3. |
| <strong>Connection assets</strong> | Those components of a transmission or distribution system which are used to provide connection services. Connection assets are those assets required to connect an electrical installation to the shared network and are all the assets from the connection point back up to and including the network coupling point. |
| <strong>Connection point</strong> | The agreed point of supply established between the Network Service Provider(s) and another Registered Participant, Non-Registered Customer or franchise customer. |
| <strong>Connection unit</strong> | A customer-specific value based on Ergon Energy’s investment in connection assets to that customer. Applies to CACs that connected prior to 1 July 2010. |
| <strong>Customer</strong> | A person or entity that receives, or wants to receive a supply of electricity for a premise, or any other distribution service from Ergon Energy. |
| <strong>Demand</strong> | The amount of electricity energy being consumed at a given time measured in either watts (W) or volt amperes (VA). The difference between the two is the power factor. |
| <strong>Designated pricing proposal charges</strong> | Typically referred to as ‘TUOS’ in this document. See the ‘Transmission Use of System (TUOS) charge’ definition below. |
| <strong>Distribution Cost of Supply (DCOS) model</strong> | The Ergon Energy model used to allocate costs to network users and convert the revenue cap, transmission-related costs (or designated pricing proposal charges) and jurisdictional scheme amounts into network tariffs. |
| <strong>Distribution Determination</strong> | The AER’s Distribution Determination sets the revenue and pricing control regime that Ergon Energy must comply with for the current regulatory control period (i.e. 2015–20). |
| <strong>Distribution network</strong> | The electrical system used to transport electricity from the high voltage TCP to distribution network users. |
| <strong>Distribution Use of System (DUOS) charge</strong> | Component of the network tariffs which recovers costs associated with connection services and/or use of the distribution network for the conveyance of electricity (i.e. Standard Control Services). |</p>
<table>
<thead>
<tr>
<th>Term</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>East Zone</td>
<td>Those areas where the network users are supplied from the distribution system connection to the national grid and have a relatively low distribution cost to supply. The LGAs covered by the East Zone are located in this document.</td>
</tr>
<tr>
<td>Electricity Market</td>
<td>Means the NEM as administered by AEMO.</td>
</tr>
<tr>
<td>Embedded Generator (EG)</td>
<td>Refer to Table 3.3.</td>
</tr>
<tr>
<td>Energy</td>
<td>The amount of electricity consumed by a consumer (or all customers) over a period of time. Energy is measured in terms of watt hours (Wh), kilowatt hours (kWh), megawatt hours (MWh) or gigawatt hours (GWh).</td>
</tr>
<tr>
<td>Excess reactive power charge (Excess kVAr)</td>
<td>A type of charge (charging parameter) included in Ergon Energy’s network tariff structure structures which is applied against the kVAr used by a customer that exceeds what they would be entitled to use at their minimum compliant power factor at authorised demand.</td>
</tr>
<tr>
<td>Fixed charge</td>
<td>A type of charge (charging parameter) included in Ergon Energy’s network tariff structures which is levied on a fixed dollar amount per day or fixed dollar amount per day per device (as is the case for unmetered supply).</td>
</tr>
<tr>
<td>Gigawatt hour (GWh)</td>
<td>1,000,000 kilowatt hours.</td>
</tr>
<tr>
<td>Individually Calculated Customer (ICC)</td>
<td>Refer to Table 3.3.</td>
</tr>
<tr>
<td>Isolated generation</td>
<td>Those areas supplied from Ergon Energy’s isolated generation assets, except for the Mount Isa system. Includes communities in Western Queensland, the Gulf of Carpentaria, Cape York, various Torres Strait Islands, Palm Island and Mornington Islands. These areas are not subject to economic regulation by the AER, but are regulated by the Queensland Government.</td>
</tr>
<tr>
<td>Jurisdictional scheme amount</td>
<td>In respect of a jurisdictional scheme, the amounts a DNSP is required under the jurisdictional scheme obligations to: (a) pay to a person (b) pay into a fund established under an Act of a participating jurisdiction (c) credit against charges payable by a person, or (d) reimburse a person, less any amounts recovered by the DNSP from any person in respect of those amounts other than under the NER (as defined in the NER).</td>
</tr>
<tr>
<td>Jurisdictional scheme charges</td>
<td>Component of the network tariff which passes through jurisdictional scheme amounts.</td>
</tr>
<tr>
<td>kVA</td>
<td>1,000 Volt-Ampere which is a measure of the apparent power flow which is a measure of the total capacity required to supply a customer’s load.</td>
</tr>
<tr>
<td>kVAr</td>
<td>1,000 Volt-Ampere reactive which is a measure of reactive power. The excess kVAr charge is applied against kVAr drawn from the network that exceeds the minimum compliant power factor level.</td>
</tr>
<tr>
<td>kW</td>
<td>1,000 Watts which is a measure of the real component of power being consumed by the consumer’s load.</td>
</tr>
<tr>
<td>Load factor</td>
<td>Measure of the percentage of time a load is used in any given period. Loads used 24 hours per day, 7 days a week have a load factor of one (1) or 100 per cent.</td>
</tr>
<tr>
<td>Long Run Marginal Cost (LRMC)</td>
<td>The cost of an incremental change in demand over a period of time in which all factors of production required to provide those services can be varied (as defined in the NER). This definition incorporates the investment required over time to maintain and expand capacity in the network to meet future demand.</td>
</tr>
<tr>
<td>Low Voltage (LV)</td>
<td>Refers to the sub 11 kV network.</td>
</tr>
<tr>
<td><strong>Major customer</strong></td>
<td>Are ICCs, CACs or EGs.</td>
</tr>
<tr>
<td>--------------------</td>
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</tr>
<tr>
<td><strong>Major Customer Connection arrangements</strong></td>
<td>Refers to the arrangements applying from 1 July 2010, where new or augmented connection assets are paid for or contributed by the major customer (i.e. not included in the network tariff).</td>
</tr>
<tr>
<td><strong>Maximum demand</strong></td>
<td>The maximum demand recorded at a customer’s individual meter or the maximum demand placed on the electrical distribution network system at any time or at a specific time or within a specific time period, such as a month. Maximum demand is an indication of the capacity required for a customer’s connection or the electrical distribution network.</td>
</tr>
<tr>
<td><strong>Megawatt hour (MWh)</strong></td>
<td>1,000 kilowatt hours</td>
</tr>
<tr>
<td><strong>Micro embedded generating unit (micro EG Unit)</strong></td>
<td>A micro embedded generating unit contemplated under Australian Standard (AS) 4777.1 – 2005. Typically customers connecting a micro embedded generating unit are classified as Standard Asset Customers for network pricing purposes.</td>
</tr>
<tr>
<td><strong>Mount Isa Zone</strong></td>
<td>Those areas supplied from the isolated Mount Isa system. This zone is not connected to the national grid and 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-Clioncurry supply network to the AER. The LGAs covered by the Mount Isa Zone are located in this document.</td>
</tr>
<tr>
<td><strong>National Electricity Market (NEM)</strong></td>
<td>The interconnected electricity grid covering Queensland, New South Wales, Victoria, Tasmania, South Australia and the Australian Capital Territory.</td>
</tr>
<tr>
<td><strong>National Electricity Rules (NER)</strong></td>
<td>Rules made under the Law which govern the operation of the NEM.</td>
</tr>
<tr>
<td><strong>National Metering Identifier (NMI)</strong></td>
<td>A unique number assigned to each metering installation.</td>
</tr>
<tr>
<td><strong>Network capacity</strong></td>
<td>The maximum demand (kW) that the distribution network can provide for at any one time.</td>
</tr>
<tr>
<td><strong>Network coupling point</strong></td>
<td>The point at which connection assets join a distribution network, used to identify the distribution service price payable by a connection customer.</td>
</tr>
<tr>
<td><strong>Network tariff</strong></td>
<td>Refers to the price (or tariff) that Ergon Energy sets to recover costs associated with the customer’s connection and use of the distribution and transmission network, and jurisdictional scheme amounts. Network tariffs comprise DUOS, TUOS and jurisdictional scheme charges.</td>
</tr>
<tr>
<td><strong>Network user</strong></td>
<td>There are four network user groups included in Ergon Energy’s network tariff structures – ICCs, CACs, SACs and EGs. For the purposes of our network pricing documents, the term ‘network user’ refers to both a ‘customer’ and an ‘EG’.</td>
</tr>
<tr>
<td><strong>Permissible kVAr quantity</strong></td>
<td>The permissible kVAr quantity is the kVAr quantity associated with authorised demand at minimum compliant power factor.</td>
</tr>
<tr>
<td><strong>Power factor</strong></td>
<td>The ratio of kW to kVA at a metering point during a defined period.</td>
</tr>
<tr>
<td><strong>Premises</strong></td>
<td>Means premises owned or occupied by the customer.</td>
</tr>
<tr>
<td><strong>Regulatory control period</strong></td>
<td>The regulatory control period is a five (5) year period set down by the AER. The current regulatory control period is 2015–16 to 2019–20.</td>
</tr>
<tr>
<td><strong>Regulatory year</strong></td>
<td>Is a specific financial year within a regulatory control period.</td>
</tr>
<tr>
<td><strong>Residential customer</strong></td>
<td>Means a customer who acquires electricity for domestic use (as defined in the Queensland EDNC).</td>
</tr>
<tr>
<td><strong>Revenue cap</strong></td>
<td>Also referred to as ‘Total Annual Revenue’. It is determined using the revenue cap formula set out in the Distribution Determination.</td>
</tr>
<tr>
<td><strong>SAC Large</strong></td>
<td>Those SACs that typically use between 100 MWh p.a. and 4 GWh p.a.</td>
</tr>
<tr>
<td><strong>SAC Small</strong></td>
<td>Those SACs that typically use less than 100 MWh p.a.</td>
</tr>
<tr>
<td>Term</td>
<td>Description</td>
</tr>
<tr>
<td>------</td>
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</tr>
<tr>
<td>Side constraint</td>
<td>Refers to the percentage by which the expected weighted average revenue to be raised from a Standard Control Service tariff class is allowed to increase by between regulatory years. Side constraints are intended to set a limit (or constraint) on the level of distribution price increase to be experienced by customers from one year to the next within a regulatory control period.</td>
</tr>
<tr>
<td>Standard Asset Customer (SAC)</td>
<td>A distribution service provided by Ergon Energy that the AER has classified as a Standard Control Service under the NER. Includes network services, some connection services (including small customer connections) and Type 7 metering services. Ergon Energy recovers our costs in providing Standard Control Services through the DUOS component of network tariffs which are billed to retailers.</td>
</tr>
<tr>
<td>Standard Control Service</td>
<td>A type of network tariff where the price per kWh varies according to when the consumption occurs. The TOU tariff may apply a different price during peak and off-peak periods.</td>
</tr>
<tr>
<td>Summer</td>
<td>The months of December, January and February.</td>
</tr>
<tr>
<td>Tariff class</td>
<td>A class of customers for one or more Direct Control Services who are subject to a particular tariff or particular tariffs (as defined in the NER).</td>
</tr>
<tr>
<td>Threshold demand</td>
<td>The amount by which a SAC Large customer’s metered monthly actual kW maximum demand is adjusted for the purposes of calculating the demand component of their network tariff. The actual demand charge for any time demand tariffs and the peak and off-peak demand charges for the STOUD tariffs are applied to the kW amount by which the recorded monthly maximum demand exceeds the relevant threshold. This demand may occur at any time during the month (actual demand charge and off-peak demand charge) or during a set peak period (peak charge). Where the monthly metered maximum demand is less than the demand threshold, the chargeable demand for that month is set to zero.</td>
</tr>
<tr>
<td>Time-of-Use (TOU)</td>
<td>A type of network tariff which passes through costs associated with use of the transmission network. This includes designated pricing proposal charges as defined under the NER plus charges levied on Ergon Energy in relation to Chumvale and three Powerlink connection points.</td>
</tr>
<tr>
<td>Transmission Use of System (TUOS) charge</td>
<td>Component of the network tariff which passes through costs associated with use of the transmission network.</td>
</tr>
<tr>
<td>Unmetered</td>
<td>A customer who takes supply where no meter is installed at the connection point.</td>
</tr>
<tr>
<td>Volume charge</td>
<td>A type of charge (charging parameter) included in Ergon Energy’s network tariff structures which is calculated using the customer’s metered energy (kWh) consumption. It may be based on a flat rate, an inclining block or TOU charging structure (depending on the customer’s applicable network tariff).</td>
</tr>
<tr>
<td>West Zone</td>
<td>Those areas outside the East Zone and connected to the national grid, which have a significantly higher distribution cost of supply than the East Zone. The LGAs covered by the West Zone are located in this document.</td>
</tr>
</tbody>
</table>
Contact information
General Manager Regulation and Pricing
Ergon Energy Corporation Limited
GPO Box 1461
BRISBANE QLD 4001
Telephone: 13 74 66
Email: netprice@ergon.com.au
Website: ergon.com.au