Ergon Energy Pricing Proposal

Distribution services for 1 July 2023 to 30 June 2024

31 March 2023

ERGON. ENERGY

NETWORK

Version	Date	Description
V1.0	31/03/2023	Pricing Proposal submitted to the AER for approval
V2.0	26/04/2023	Updated Pricing Proposal submitted to the AER for approval

Contents

Overview

This pricing proposal is submitted to the Australian Energy Regulator (AER) as required under the requirements of the National Electricity Rules (NER). It provides details of Ergon Energy's proposed 2023-24 network prices for Standard Control Services and Alternative Control Services.

Our pricing proposal is based on the AER approved 2020-25 Tariff Strategy Statement (TSS).

Ergon Energy's tariff offering and tariff assignment rules remain unchanged from the prior year.

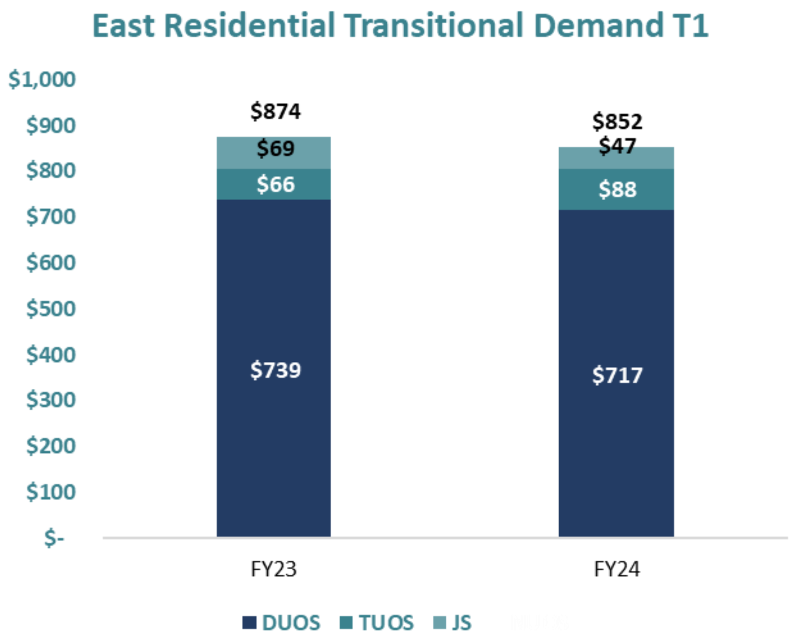
Ergon Energy's network use of system (NUOS) prices represent the aggregation of distribution use of system (DUOS) charges, transmission cost recovery charges (also referred to as designated pricing proposal charges (DPPC)) and jurisdictional scheme (JS) charges.

Ergon Energy estimates that majority residential and small business with smart meters are expected to experience a decrease in their network charges in 2023-24 compared with 2022-23 network charges (between 0.4% and 4.6%).

Residential and small business customers with smart metering will experience a larger decrease in their network bill compared with basic meter customers. These customer impacts reflect Ergon Energy's tariff strategy which provides gradual incentives to customers to transition to cost reflective tariffs.

For an average residential customer in the East pricing zone on cost-reflective tariff consuming 5.5 MWh per annum this equates to a $22 decrease in annual NUOS bill.

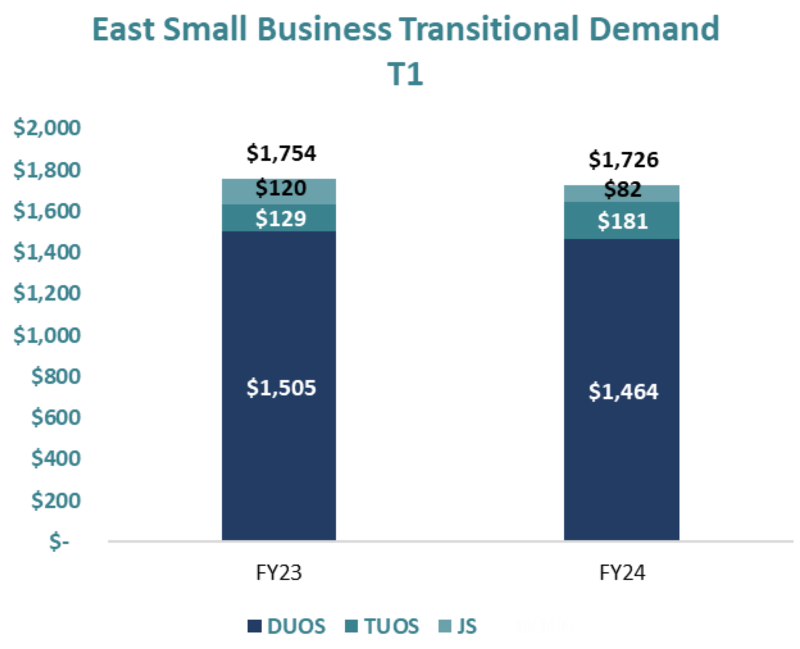
Figure 1: Average residential customer Ergon Energy network charges (East pricing zone)[1]



[1] Network bill impacts are based on a typical residential customer consuming 5,478 kWh pa with a monthly peak demand of 3.2 kW.

For an average small business customer on a cost reflective tariff, consuming 14.8 MWh per annum this equates to a $28 decrease in annual NUOS bill.

Figure 2: Average small business customer Ergon Energy network charges (East pricing zone)[2]



Majority of Ergon Energy's large business customers (SAC Large) in the East pricing zone are expected to experience an increase in network charges of between 3.8% to 4.8% in 2023-24, compared to 2022-23.

This change in network rates is driven by:

- the forecast decrease in distribution revenue (as 2021-22 revenue under-recovery was less than forecast in prior year's pricing proposal requiring us to return revenue to customers)
- increase in Powerlink's transmission charges and
- a decrease in the jurisdictional scheme amounts that we are required to recover from customers.

[2] Network bill impacts are based on a typical small business customer consuming 14,774 kWh pa, with a monthly peak demand of 7.36 kW.

1. Introduction

1.1 Purpose

This document is Ergon Energy's annual Pricing Proposal for 2023-24 (Pricing Proposal), the fourth regulatory year of the 2020-25 regulatory control period. In accordance with clause 6.18.2(a)(2) of the National Electricity Rules (the NER)[3], it is submitted for approval to the Australian Energy Regulator (AER) at least 3 months before the commencement of the relevant regulatory year.

This Pricing Proposal is based on the AER approved 2020-25 TSS and outcomes in the AER's Final Decision. Ergon Energy's approved 2020-25 TSS is available on both our website[4] and the AER's website[5].

We have also provided the following attachments to the AER as part of this Pricing Proposal:

- Attachment 1 – 2023-24 Network Price List
- Attachment 2 – 2024-25 Indicative Pricing Schedule
- Attachment 3 – 2023-24 annual SCS pricing model
- Attachment 4 – 2023-24 annual ACS pricing model

1.2 Background

Ergon Energy is subject to economic regulation by the AER under the National Electricity Law and the NER. The AER determines how Ergon Energy's distribution services are classified and in turn the nature of economic regulation. This is important as it determines how prices will be set and how revenue is recovered from customers. The AER approves prices for services it classifies as Direct Control Services.

Direct Control Services are divided into two subclasses:

- **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. The AER applies a revenue cap form of control to Standard Control Services. Ergon Energy recovers the costs in providing these services through network tariffs billed to retailers.
- **Alternative Control Services** are akin to a 'user-pays' system whereby the whole cost of the service is paid by those customers who benefit from it, rather than recovered from all customers. Ergon Energy's Alternative Control Services are comprised of:
  - Connection services – services relating to the electrical or physical connection of a customer to the network (including temporary connections, de-energisations, re-energisations and supply abolishment).
  - Metering services – services include Type 6 default metering services and auxiliary metering services.
  - Public Lighting services – services relating to the provision, installation and maintenance of public lighting assets and emerging public lighting technology.

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[3] The National Electricity Rules, Version 195.
[4] https://www.ergon.com.au/network/network-management/network-pricing/network-tariffs
[5] https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/ergon-energy-determination-2020-25/final-decision

- Network ancillary services – customer and third party-initiated services related to the common distribution services but for which a separate charge applies (includes network safety services, non-standard network data requests, security lighting services).

This Pricing Proposal (including the attachments) sets out proposed tariffs and services for all Ergon Energy's Direct Control Services for the 2023-24 regulatory year.

1.3 Regulatory framework

1.3.1 Compliance with the NER

Ergon Energy's network tariffs have been developed in compliance with the regulatory requirements in the NER. In accordance with the NER, our objective is to ensure that the tariffs charged for 2023-24 in the provision of Direct Control Services reflect Ergon Energy's cost of providing these services. This is achieved by setting the level (or price) of tariffs in a manner that is consistent with the pricing principles as outlined in the NER. More detailed information about our application of, and compliance with, the distribution pricing principles is set out in Appendix A of this Pricing Proposal.

1.3.2 Consistency with the Distribution Determination

The 2020-25 Distribution Determination sets the revenue and pricing control regime that we must comply with for the regulated distribution services provided over the current regulatory control period. The revenue approved in the Distribution Determination forms the basis of Ergon Energy's prices provided in Attachment 1 – 2023-24 Network Price List and Attachment 2 – Indicative Pricing Schedule 2024-25. We confirm this Pricing Proposal complies with AER's Final Decision.

1.3.3 Consistency with the approved TSS

The TSS sets out our proposed tariff classes, tariffs and tariff structures that will apply over the regulatory control period. This Pricing Proposal is based on our approved 2020-25 TSS, and several sections of this Pricing Proposal therefore refer to the TSS for further information. There are no departures from the approved tariff classes, tariffs and charging parameters.

1.3.4 Queensland Government cap on fee-based services

The Queensland Government has historically set maximum price caps to apply to a subset of Ergon Energy's Alternative Control Services through Schedule 8 of the *Electricity Regulation 2006*. Since the Schedule 8 maximum prices are imposed through Queensland legislation, they take precedence over the Alternative Control Services prices approved by the AER.

It is important to note that the prices included in our Pricing Proposal have been derived under the AER's price-setting requirements. These prices, if subject to the Schedule 8 price caps, may be higher than those charged to customers.

2. Tariff classes and tariffs for Standard Control Services

This chapter sets out Ergon Energy's tariff classes, tariffs, charging parameters and tariff assignment policies for Standard Control Services in accordance with our approved TSS for the 2020-25 regulatory control period.

2.1 Tariff classes

We have categorised Standard Control Services customers into three tariff classes mainly based on the voltage level at which customers are connected to the network as this ensures customers who impose similar costs on the network are classified together with similar tariff structures. Our tariff classes are listed in the table below.

Table 1: Tariff classes

Tariff class	Eligible customers
Standard Asset Customers (SAC)	All customers connected at LV with installed capacity up to 1,000kVA are classified as SACs. SAC tariffs are based on: • average charges for dedicated connection assets; plus • average charges for use of the shared distribution network, including common and non-system assets.
Connection Asset Customers (CAC)	Customers with a network coupling point at 66 kV, 33 kV, 22 kV, 11 kV and installed capacity above 1,000 kVA who are not assigned to the ICC tariff class are allocated to the CAC tariff class. CAC tariffs are based on: • the actual dedicated connection assets utilised by the customer; plus • average charges for use of the shared distribution network, including common and non-system assets.
Individually Calculated Customers (ICC)	Customers are assigned to the ICC tariff class if they are coupled to the network at 132 kV, 110 kV, 66 kV or 33 kV and with installed capacity above 10 MVA. Customers may also be assigned to the ICC tariff class if they are coupled to the network at the 132 kV, 110 kV, 66 kV or 33 kV and with installed capacity below 10 MVA where[a]: • A customer has a dedicated distribution system which is quite different and separate from the remainder of our distribution system • A customer is connected at or close to a Transmission Connection Point, or • At the determination of the DNSP, the nature of the customer's connection to the network, and/or usage of the network, make average prices inappropriate • Subject to the Policy set out in Appendix A of our 2020-25 TSS, eligible CAC customers accessing transitional or obsolete retail tariffs and who can demonstrate that they are facing extraordinary customer impact post retirement of the retail tariffs and that this financial impact is directly attributable to their network charges[b]. ICC tariffs allocate residual costs in an equitable and efficient manner by basing this allocation on: • the actual dedicated connection assets utilised by the customer; plus • the customer's specifically identified portion of the shared distribution network utilised for the electricity supply, including common and non-system assets.

Note:

a. Some existing customers coupled to the HV network at lower voltage levels will remain assigned to the ICC tariff class for legacy reasons

b. In accordance with the Policy set out in Appendix A of our TSS, applications for ICC tariffs closed on 30 June 2021.

It should be noted that we do not make reference to customer's export load in assigning customers to tariff classes or network tariffs.

2.2 Tariffs and charging parameters

Each tariff class consists of a number of different network tariffs that are established on the same basis as the tariff class. The table below sets out the individual tariffs in each tariff class.

Table 2: 2023-24 Network tariffs by tariff class

Tariff class	Customer type	Primary Tariffs	Secondary tariffs
Standard Asset Customers (SAC)	Residential	• Residential Inclining Block (IBT) • Residential Transitional Demand • Residential Demand • Residential Time of Use Energy	• Volume Night Controlled • Volume Controlled
	Small business	• Small Business Inclining Block (IBT) • Small Business Wide Inclining Fixed Tariff (WIFT) • Small Business Transitional Demand • Small Business Demand • Small Business Time of Use Energy • Small Business Primary Load Control • Transitional Network ToU Energy Tariff 1[a] • Transitional Network ToU Energy Tariff 2[a] • Transitional Network Dual Rate Demand Tariff 3[a]	• Volume Night Controlled • Volume Controlled
	Large customer	• Demand Large • Demand Medium • Demand Small • Large Business Time of Use Demand • Seasonal Time of Use Demand[b] • Large Business Primary Load Control • Large Residential Energy • Large Business Energy	• Large Business Secondary Load Control
	Other	• Unmetered Supply • Solar FiT[b]	
Connection Asset Customers (CAC)		• CAC 66kV • CAC 33kV • CAC 22/11kV Bus • CAC 22/11kV Line • Seasonal Time of Use Demand 11 or 22kV Bus • Seasonal Time of Use Demand 11 or 22kV Line • Seasonal Time of Use Demand 33 or 66kV	
Individually Calculated Customers (ICC)		• ICC tariff	

Note:

a. Introduced on 1 July 2021 and grandfathered immediately

b. Grandfathered tariffs (closed to new customers)

The types of charges applied to recover network costs are shown in Table 3.

Table 3: Types of charges for Standard Control Services

Charge	Charging parameters	Application to tariffs
Fixed (or access) charge	Represented as a rate ($) per day or rate ($) per day per device.	Applies to all primary tariffs.
Usage (or volume) charge	Represented as a rate ($) per kWh. Within a tariff structure, volume charge rates can be flat or be applied to different blocks (based on consumption) or times (peak and off-peak).	Applies to all primary and secondary tariffs.
Block usage (or inclining volume block)	Represented as a rate ($) per kWh. Different charges apply to each consumption block. • For IBT Residential the blocks are: 0<1,000kWh; 1,000<6,000kWh and 6,000<100,000kWh • For IBT Business the blocks are: 0<1,000kWh; 1,000<20,000kWh and 20,000<100,000kWh.	Applies to the following tariffs: • Residential IBT • Small Business IBT
Inclining fixed charge	Represented as a rate ($) per day. Different charges apply to 20 MWh per year blocks. There are five blocks: 0<20 MWh per year, 20<40 MWh per year, 40<60 MWh per year, 60<80 per year, and >80 MWh per year.	Applies to the following tariffs: • Small Business WIFT • Small Business ToU Energy
Demand charge	Represented as either a rate ($) per kW or a rate ($) per kVA. Within a tariff structure, demand charge rates can be: • Applied year round (with different peak window rates) • Calculated based on: ○ A single period in the month, or ○ The maximum demand within a peak demand window Some tariff structures include a threshold (the demand charge is only calculated for demands recorded above a particular level).	Applies to the following tariffs: • Residential Transitional Demand • Residential Demand • Small Business Transitional Demand • Small Business Demand • Demand Small • Demand Medium • Demand Large • Seasonal Time of Use Demand • all CAC tariffs and the ICC site-specific tariffs.
Excess demand charge	Represented as a rate ($) per excess kVA. It is measured as a single maximum demand outside the peak charging window minus the maximum demand during the peak period in the billing period. Where the maximum demand outside the evening window is less than the highest maximum demand inside the evening window in the billing period, the excess demand charge for that billing period is set to zero.	• The charge applies the SAC Large ToU Demand tariff.
Capacity charge	Represented as a rate ($) per kVA	• The charge applies to the ICC site-specific tariffs and CAC any time demand tariffs.
Connection unit charge	Represented as a rate ($) per connection unit per day	• The charge applies to all CAC tariffs

2.3 Tariff assignment process

Procedures for the assignment of new customers and reassignment of existing customers to Standard Control Services tariff classes and tariffs are contained in our 2020-25 TSS. Additional information is provided in our Network Tariff Guide.

3. Charges for Standard Control Services

This chapter demonstrates how our network tariffs for 2023-24 comply with the regulatory requirements in Chapter 6 of the NER, the AER's revenue determination and our approved TSS.

The proposed network prices for 2023-24 for all Standard Control Services are included in Attachment 1 of this Pricing Proposal.

3.1 Forecast NUOS revenue requirement for 2023-24

Our final network charges (NUOS charges) include the following:

- Distribution Use of System (DUOS) charges, which reflect Ergon Energy's electricity distribution costs,
- Designated Pricing Proposal Charges (DPPC) (or Transmission Use of System (TUOS) charges) which reflect the costs associated with transmission of electricity, and
- Jurisdictional Scheme amounts which Ergon Energy must pay pursuant to State government requirements.

The total revenue we will need to recover in 2023-24 via our NUOS charges is provide in table below.

Table 4: Forecast NUOS revenue requirement for 2023-24 ($)

Revenue component	Forecast revenue required for 2023-24
Distribution use of system (DUOS)	$1,281,959,672
Transmission use of system (TUOS)	$275,065,902
Jurisdictional schemes	$46,035,480
Total Network use of system (NUOS)	**$1,603,061,053**

3.2 DUOS charges

3.2.1 Calculation of annual revenue for DUOS

As set out in the AER's Distribution Determination (Attachment 13), Ergon Energy's DUOS charges are regulated using a revenue cap. The revenue cap for any given regulatory year is the Total Allowable Revenue (TAR) calculated using the formula set by the AER.

Table 5 applies the revenue cap formula to calculate our TAR for 2023-24 and demonstrates our compliance with the control mechanism.

Table 5: DUOS Total Allowable Revenue for 2023-24

Component	Formula	2023-24 Value
Adjusted annual smoothed revenue requirement (t-1)	AAR_{t-1}	$1,183,108,237
CPI	ΔCPI_t	7.832%
X-factor	X_t	0.707%
Adjusted annual smoothed revenue requirement (t)	$AAR_t = AAR_{t-1} \times (1 + \Delta CPI_t) \times (1 - X_t)$	**$1,266,741,190**
Sum of DMIS, DMIA and STPIS amounts	I_t	-$16,341,269
Annual adjustment factors	$B_t^{'}$	$31,559,751
Cost pass through amounts	C_t	$0
Total Allowable Revenue	$TAR_t \geq AAR_t + I_t + B_t + C_t$	**$1,281,959,672**
Proposed revenue	*Proposed revenue*	$1,281,959,672
Compliance with revenue cap	**TAR>= Proposed revenue**	**YES**

3.2.2 DUOS unders and overs account

Under a revenue cap, our revenues are adjusted annually to clear any under or over recovery of actual revenue recovered through DUOS charges. This 'unders and overs' rebalancing process is undertaken as part of the annual pricing cycle to ensure we recover no more and no less than the TAR approved by the AER for any given year. Under these arrangements, there is a lag between the year in which the DUOS under or over recovery occurs and the year in which adjustments are made to prices to 'clear' the under or over recovery.

Consistent with the Distribution Determination we are required to maintain a DUOS unders and overs account in our annual pricing proposal and provide entries for the most recently completed regulatory year (t-2), the current regulatory year (t-1) and the next regulatory year (t).[6]

The AER also requires that Ergon Energy's amounts for the most recently completed regulatory year (t-2) be audited. We believe this requirement is met as the amounts provided for 2021-22 are based on audited information lodged in our Regulatory Information Notice (RIN) submission. The unders and overs account is presented in Table 6.

[6] Ergon Energy's Determination decision 2020 to 2025, Attachment 13 – Control Mechanisms, June 2020.

Table 6: DUOS unders and overs account ($'000)

Unders/overs account component	2021-22 Year t-2 (actual) $	2022-23 Year t-1 (estimate) $	2023-24 Year t (forecast) $
(A) Revenue from DUOS charges	**$1,124,423,058**	**$1,271,362,446**	**$1,281,959,672**
(B) Less TAR for regulatory year =	**$1,163,502,966**	**$1,230,081,881**	**$1,250,399,921**
+ Adjusted annual smoothed revenues (AARt)	$1,164,549,680	$1,183,108,237	$1,266,741,190
+ Incentive scheme amounts (It)	-$1,046,714	$46,973,644	-$16,341,269
+ Annual adjustments (Bt)	$0	$0	$0
+ Cost pass through amount (Ct)	$0	$0	$0
(C) Revenue deliberately under-recovered in year	$0	$0	$0
(A minus B plus C) Under/over recovery of revenue for regulatory year	**-$39,079,908**	**$41,280,565**	**$31,559,751**
DUOS unders and overs account			
Nominal WACC (per cent)	3.123%	5.755%	10.266%
Opening balance	-$28,001,034	-$68,560,880	-$30,054,732
Interest on opening balance	-$874,427	-$3,945,638	-$3,085,402
Under/over recovery of revenue for regulatory year	-$39,079,908	$41,280,565	$31,559,751
Interest on under/over recovery for regulatory year	-$605,510	$1,171,221	$1,580,384
Closing balance	**($68,560,880)**	**($30,054,732)**	**($0)**

3.2.3 Forecast weighted average revenue

The following table sets out the expected weighted average DUOS revenue for each tariff class and the per cent change from 2022/23 to 2023/24 for each tariff class.

Table 7: Expected weighted average DUOS revenue by tariff class

Tariff class	2022-23 Weighted average revenue	2023-24 Weighted average revenue	% Change
SAC	$1,185,707,324	$1,149,452,264	-3.06%
CAC	$70,751,245	$69,435,800	-1.86%
ICC	$57,118,485	$56,339,847	-1.36%
Total	**$1,313,577,054**	**$1,275,227,912**	-2.92%

Note: All amounts are GST exclusive

The 2022/23 and 2023/24 notional DUOS revenues in this table are both calculated using 2023/24 forecast quantities

Trial tariff revenue for 2023/24 is excluded from the weighted avearge calculations

3.2.4 Tariff class side constraints

For each regulatory year after the first year of a regulatory control period, side constraints apply to the weighted average revenue raised from each tariff class (that is, the expected weighted average revenue from DUOS to be raised from each tariff class in year (t) must not exceed the corresponding expected weighted average revenue from the preceding year (t-1) by more than the permissible percentage determined as per the side constraint formula).[7]

The side constraints formula is set out in the AER's Determination Decision (Attachment 13). The table below sets out the maximum permissible percentage increase in the weighted average revenue raised from each tariff class, as determined by the side constraint formula.

7 Revenue in year t-1 is based on the sum of the prices in year t-1 multiplied by the associated forecast quantities for year t.

Table 8: Calculation of side constraint limit

Component	Formula	Value
CPI	ΔCPI_t	7.83%
X-factor (if X-factor>0, X=0)	X_t	0.00%
DMIS, DIMIA & STPIS adjustments	I_t	-4.82%
Annual adjustment factors	$B_t^{'}$	-4.34%
Cost pass through amounts	C_t	0.00%
Side constraint limit	$\leq (1+\Delta CPI_t) \times (1-X_t) \times (1+2\%) + I_t' + B_t' + C_t'$	**100.83%**

Note: If X>0, then X will be set equal to zero for the purposes of the side constraint formula.

As demonstrated in Table 7, the change in weighted average DUOS revenue for all tariff classes is less than permitted by the side constraint limit, demonstrating that there is no economic cross-subsidy between tariff classes.

3.2.5 Revenue lies between avoidable and stand-alone costs

The pricing principles in the NER requires us to ensure the DUOS revenue expected to be recovered from each tariff class lies on or between the bounds of stand-alone and avoidable costs. The table below demonstrates our compliance with this requirement of the NER.

Table 9: Comparison of 2023-24 Expected DUOS revenue vs Avoidable and Standalone costs

Tariff class	Avoidable cost	2023-24 Forecast DUOS revenue	Stand Alone cost
SAC	$631,662,483	$1,149,452,264	$1,159,819,574
CAC	$65,792,008	$69,435,800	$888,344,548
ICC	$54,026,968	$56,339,847	$401,275,773

3.2.6 Tariffs to be based on long run marginal cost

The pricing principles in the NER require each tariff to be based on the LRMC of providing the service to which it relates to the retail customers assigned to that tariff.

In our tariff-setting for 2023-24, we have applied the approach to LRMC detailed in our TSS:

- Incorporating the LRMC values in the demand charge parameter of the demand-based tariffs as it is considered the most suitable mechanism to signal the cost of future network augmentation. For the tariffs without a demand charge parameter, LRMC has been allocated to the 'peak' usage charge of time-of-use usage/volumetric tariffs.
- Gradually aligning the demand charge or 'peak' usage change with our LRMC estimates.
- Incorporating a muted LRMC signal in our Transitional Demand tariffs for SAC Small customers compared to the standard demand tariffs to allow customers to adjust to tariffs they may not be familiar with and to mitigate the potential for network charge impact.

Ergon Energy’s LRMC estimates for each demand and ‘peak’ usage charge parameter (per tariff) are provide below.

Table 10: LRMC estimates and application in tariff setting

Tariff group	Tariff name	NTC	Charge	LRMC Voltage Level	Annual LRMC 2023-24		100% LRMC charge	Percentage of LRMC applied	2023-24 Charge
				Voltage	$/kW	$/kVA	$/kW, kVA, kWh	%	$
CAC	CAC 66kV	EC66	Actual Demand kVA	Sub-Transmission		85.349	7.112	51.6%	3.666
CAC	CAC 33kV	EC33	Actual Demand kVA	Sub-Transmission		85.349	7.112	53.4%	3.798
CAC	CAC 22/11kV Bus	EC22B	Actual Demand kVA	High Voltage		142.984	11.915	38.6%	4.605
CAC	CAC 22/11kV Line	EC22L	Actual Demand kVA	High Voltage		169.792	14.149	65.6%	9.288
CAC	Seasonal TOU Demand CAC Higher Voltage (33-66kV)	EC66TOU	Actual Demand Charge Peak	Sub-Transmission		85.349	28.450	50.1%	14.266
CAC	Seasonal TOU Demand CAC 22/11kV Bus	EC22BTOU	Actual Demand Charge Peak	High Voltage		142.984	47.661	100.0%	47.661
CAC	Seasonal TOU Demand CAC 22/11kV Line	EC22LTOU	Actual Demand Charge Peak	High Voltage		169.792	56.597	115.0%	65.087
SACL	Large ToU Demand	ELTOUD	Actual Demand Peak kVA	Low Voltage		254.556	21.213	69.4%	14.721
SACL	Demand Large	EDLT	Actual Demand kW	Low Voltage	282.840		23.570	79.5%	18.740
SACL	Demand Large	EDLT	Actual Demand kVA	Low Voltage		254.556	21.213	79.6%	16.877
SACL	Demand Medium	EDMT	Actual Demand kW	Low Voltage	282.840		23.570	100.0%	23.570
SACL	Demand Medium	EDMT	Actual Demand kVA	Low Voltage		254.556	21.213	100.0%	21.213
SACL	Demand Small	EDST	Actual Demand kW	Low Voltage	282.840		23.570	100.0%	23.570
SACL	Demand Small	EDST	Actual Demand kVA	Low Voltage		254.556	21.213	100.0%	21.213
SACL	Seasonal ToU Demand	ESTOUDC	Actual Demand Peak kW	Low Voltage	282.840		71.653	100.0%	71.653
SACS Bus	Small Business Demand	EBDEM	Peak Demand kW	Low Voltage	282.840		23.570	24.1%	5.677
SACS Bus	Small Business Transitional Demand	EBTDEM	Peak Demand kW	Low Voltage	282.840		23.570	8.9%	2.104
SACS Bus	Small Business ToU Energy	EBTOUE	Volume Evening kWh	Low Voltage	282.840		0.85156	33.2%	0.28242
SACS Res	Residential Demand	ERDEM	Peak Demand kW	Low Voltage	282.840		23.570	24.4%	5.757
SACS Res	Residential Transitional Demand	ERTDEM	Peak Demand kW	Low Voltage	282.840		23.570	10.8%	2.543
SACS Res	Residential ToU Energy	ERTOUE	Volume Evening kWh	Low Voltage	282.840		0.67816	21.4%	0.14493
CAC	CAC 66kV	WC66	Actual Demand kVA	Sub-Transmission		181.222	15.102	57.3%	8.660
CAC	CAC 33kV	WC33	Actual Demand kVA	Sub-Transmission		181.222	15.102	100.0%	15.102
CAC	CAC 22/11kV Bus	WC22B	Actual Demand kVA	High Voltage		343.497	28.625	100.0%	28.625
CAC	CAC 22/11kV Line	WC22L	Actual Demand kVA	High Voltage		664.458	55.372	68.8%	38.093
CAC	Seasonal TOU Demand CAC Higher Voltage (33-66kV)	EC66TOU	Actual Demand Charge Peak	Sub-Transmission		181.222	60.407	59.4%	35.897
CAC	Seasonal TOU Demand CAC 22/11kV Bus	EC22BTOU	Actual Demand Charge Peak	High Voltage		343.497	114.499	100.0%	114.499
CAC	Seasonal TOU Demand CAC 22/11kV Line	EC22LTOU	Actual Demand Charge Peak	High Voltage		664.458	221.486	100.0%	221.486
SACL	Large ToU Demand	WLTOUD	Actual Demand Peak kVA	Low Voltage		742.748	61.896	68.4%	42.343
SACL	Demand Large	WDLT	Actual Demand kW	Low Voltage	825.276		68.773	100.0%	68.773
SACL	Demand Large	WDLT	Actual Demand kVA	Low Voltage		742.748	61.896	100.0%	61.896
SACL	Demand Medium	WDMT	Actual Demand kW	Low Voltage	825.276		68.773	100.0%	68.773
SACL	Demand Medium	WDMT	Actual Demand kVA	Low Voltage		742.748	61.896	100.0%	61.896
SACL	Demand Small	WDST	Actual Demand kW	Low Voltage	825.276		68.773	100.0%	68.773
SACL	Demand Small	WDST	Actual Demand kVA	Low Voltage		742.748	61.896	100.0%	61.896
SACL	Seasonal TOU Demand	WSTOUDC	Actual Demand Peak kW	Low Voltage	825.276		209.070	95.0%	198.688
SACS Bus	Small Business Demand	WBDEM	Peak Demand kW	Low Voltage	825.276		68.773	18.4%	12.664
SACS Bus	Small Business Transitional Demand	WBTDEM	Peak Demand kW	Low Voltage	825.276		68.773	5.2%	3.570
SACS Bus	Small Business ToU Energy	WBTOUE	Volume Evening kWh	Low Voltage	825.276		2.58339	28.0%	0.72355
SACS Res	Residential Demand	WRDEM	Peak Demand kW	Low Voltage	825.276		68.773	30.1%	20.717
SACS Res	Residential Transitional Demand	WRTDEM	Peak Demand kW	Low Voltage	825.276		68.773	6.1%	4.211
SACS Res	Residential ToU Energy	WRTOUE	Volume Evening kWh	Low Voltage	825.276		1.84429	31.2%	0.57499
SACL	Large ToU Demand	MLTOUD	Actual Demand Peak kVA	Low Voltage		116.005	9.667	100.0%	9.667
SACL	Demand Large	MDLT	Actual Demand kW	Low Voltage	128.894		10.741	100.0%	10.741
SACL	Demand Large	MDLT	Actual Demand kVA	Low Voltage		116.005	9.667	100.0%	9.667
SACL	Demand Medium	MDMT	Actual Demand kW	Low Voltage	128.894		10.741	115.0%	12.352
SACL	Demand Medium	MDMT	Actual Demand kVA	Low Voltage		116.005	9.667	115.0%	11.117
SACL	Demand Small	MDST	Actual Demand kW	Low Voltage	128.894		10.741	125.0%	13.426
SACL	Demand Small	MDST	Actual Demand kVA	Low Voltage		116.005	9.667	125.0%	12.084
SACL	Seasonal TOU Demand	MSTOUDC	Actual Demand Peak kW	Low Voltage	128.894		32.653	179.0%	58.449
SACS Bus	Small Business Demand	MBDEM	Peak Demand kW	Low Voltage	128.894		10.741	46.1%	4.949
SACS Bus	Small Business Transitional Demand	MBTDEM	Peak Demand kW	Low Voltage	128.894		10.741	19.1%	2.057
SACS Bus	Small Business ToU Energy	MBTOUE	Volume Evening kWh	Low Voltage	128.894		0.39322	58.4%	0.22969
SACS Res	Residential Demand	MRDEM	Peak Demand kW	Low Voltage	128.894		10.741	46.6%	5.004
SACS Res	Residential Transitional Demand	MRTDEM	Peak Demand kW	Low Voltage	128.894		10.741	24.3%	2.607
SACS Res	Residential ToU Energy	MRTOUE	Volume Evening kWh	Low Voltage	128.894		0.27501	35.1%	0.09650

Least distortionary recovery of residual costs

In establishing the 2023-24 network tariffs, we confirm that it has been necessary to allocate residual costs to recover the portion of the revenue cap that that could not be fully recovered through the LRMC-based charging parameters. This means that we have to recover the revenue shortfall through the fixed, off-peak volume and capacity charges. Residual recovery within each customer group has been based on selecting combinations that minimise distortion of the LRMC signal.

3.3 Designated pricing proposal charges

Designated pricing proposal charges (DPPC) recover the payments we make for:

- the use of Powerlink's transmission network to deliver high voltage electricity from generators to Ergon Energy's distribution network
- payments made to other DNSPs for the supply of distribution services
- avoided transmission charges paid to eligible embedded generators (EGs).

Further information about our transmission costs is provided below.

3.3.1 Transmission costs

DPPC paid to TNSPs (Powerlink)

Powerlink charges Ergon Energy at the Transmission Connection Point level. Their charges comprise both daily supply and variable components, namely:

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

Powerlink also charges Ergon Energy for the entry and exit services at three connection points – Stoney Creek, Kings Creek and Oakey Town.

Payment to other DNSPs

In the Toowoomba area, Ergon Energy take supply from Energex at the Postman's Ridge Transmission Connection Point and distribute to a group of customers in the area. Energex bills Ergon Energy a network service charge for these network services. These charges are forecast each year and added to the Powerlink charges at the Middle Ridge Transmission Connection Point.

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 DPPC (TUOS) charges using an allocation method similar to that applied to Powerlink charges in the other TUOS Regions.

Avoided TUOS charges

Where we are liable to pay an Avoided TUOS payment to an EG, the payment amount is recovered as part of the DPPC charges passed through to all customers. This allocation is premised on the fact that avoided TUOS do not solely impact on the transmission connection point to which the EG is connected but also benefit all customers.

Avoided TUOS payments recognise that energy supplied to the electricity distribution network by the EG would have otherwise been supplied from the transmission network. In accordance with the NER, to calculate the avoided TUOS payments for eligible EGs, we:

(a) Determine the charges for the locational component of prescribed DPPC services that would have been payable by Ergon Energy had the EG not injected any energy at its connection point during that financial year.

(b) Determine the amount by which the charges calculated in (a) exceeds the amount for the locational component of prescribed DPPC services actually payable by Ergon Energy.

(c) Credit the value from (b) to the EG account.

Avoided TUOS payments will generally be remitted in the form of a lump sum payment after 30 June each year. The estimated total amount in avoided TUOS liability to EGs accrued in 2022-23 is included in our DPPC unders and overs account.

Transmission system strength charges

As required by the recently implemented changes in the NER, Ergon Energy as a Distribution Network Service Provider will pass through system strength charges as determined by the system strength service provider (Powerlink) in Queensland, as required to relevant parties (being distribution customers and embedded generators) at system strength connection points on the distribution network. The amount, structure, and timing of the amount billed by Ergon Energy will replicate as far as is reasonably practicable the amount, structure, and timing of the corresponding system strength charge billed to Ergon Energy by Powerlink.

In 2023-24 there is no revenue expected from system strength charges.

3.3.2 DPPC unders and overs account

In accordance with the NER and the AER's requirements set out in the Distribution Determination, we are required to maintain a DPPC unders and overs account. Table 11 sets out Ergon Energy's DPPC unders and overs account. We have set the revenue from DPPC charges to achieve a closing balance (for 2022/23) as close as possible to zero.

The amounts for 2021-22 are based on audited information lodged in our RIN.

Table 11: DPPC unders and overs account

Unders/overs account component	2021-22 Year t-2 (actual) $	2022-23 Year t-1 (estimate) $	2023-24 Year t (forecast) $
(A) Revenue from designated pricing proposal charges (DPPC)	**$271,262,354**	**$227,347,918**	**$275,065,902**
(B) Less DPPC related payments for regulatory year =	**$271,258,117**	**$246,158,479**	**$253,728,583**
+ DPPC to be paid to Transmission Network Service Provider	$265,632,337	$241,034,902	$248,486,941
+ Avoided TUoS/DPPC payments	$2,553,415	$2,408,033	$2,334,669
+ Inter-distributor payments	$3,072,365	$2,715,544	$2,906,972
(C) Revenue deliberately under-recovered in year	$36,193		
(A minus B plus C) Under/over recovery of revenue for regulatory year	**$40,431**	**-$18,810,561**	**$21,337,320**
DPPC unders and overs account			
Nominal WACC (per cent)	3.123%	5.755%	10.266%
Opening balance	-$934,323	-$922,443	-$20,319,787
Interest on opening balance	-$29,177	-$53,086	-$2,086,018
Under/over recovery of revenue for regulatory year	$40,431	-$18,810,561	$21,337,320
Interest on under/over recovery for regulatory year	$626	-$533,697	$1,068,486
Closing balance	**($922,443)**	**($20,319,787)**	**($0)**

3.3.3 Recovery of transmission costs

Where administratively efficient, the forecast DPPC will be passed on to customers in the same form of price structure as it is received.

ICC tariffs

For ICCs, our network tariffs preserve the economic signals present in the structure of the DPPC as the charges are based on the relevant transmission connection point. This provides the greatest cost-reflectivity for these customers and is a feasible method for calculating charges since the number of such customers is relatively small.

SAC and CAC tariffs

DPPC cost amounts are allocated to SAC and CAC tariffs proportionally based on a mixture of customer numbers, anytime maximum demands and volumes.

DPPC charges for CAC tariffs are based on average DPPC charges. This provides a degree of cost-reflectivity for this group of customers while recognising the practical difficulties of calculating individual charges for each customer connected at the 11 kV network.

For SAC and CAC customers, Transmission Connection Points are allocated to one of three geographical transmission regions. DPPC charges for this group of customers are calculated based on the combined totals. This has the advantage of simplifying tariffs, while still providing clear DPPC locational signals for these customers.

DPPC charges for our new cost reflective SAC tariffs are recovered from the same tariff structure as DUOS charges (fixed charge, demand charge and volume charges). For our legacy IBT tariffs, the DPPC charges are not recovered through the same tariff structures as DUOS charges.

CAC Customers with alternate supplies

For those CAC customers that have a primary and alternate supply (as deemed by Ergon Energy), the following DPPC arrangements apply:

- Primary supply – standard rates and conditions for each charge
- Alternate supply – standard rates and conditions for each charge, except:
    - no DPPC fixed charge applies
    - the authorised demand for the DPPC capacity charge is set at zero.

This means, with the exception of the DPPC 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 Anytime Maximum Demand in any month when a changeover to the alternate supply takes place.

3.4 Jurisdictional scheme charges

Jurisdictional schemes are certain programs implemented by state governments that place legislative obligations on DNSPs. The jurisdictional schemes we are subject to comprise:

- the Solar Bonus Scheme which obliges Ergon Energy to make Feed-in Tariff payments to eligible customers for energy supplied into our distribution network from specific micro-embedded generators[8]
- the energy industry levy covering a proportion of the Queensland Government's funding commitments for the AEMC which we are obligated to pay under our Distribution Authority.

The jurisdictional schemes Ergon Energy is subject to have not been amended since the last jurisdictional scheme approval date.

Jurisdictional scheme amounts are recovered from customers through fixed and volume charges.

3.4.1 Jurisdictional scheme unders and overs account

Under the NER and the AER's Distribution Determination, we are required to provide amounts for the unders and overs relating to jurisdictional schemes. Table 12 provides the forecast 2022-23 balance of Ergon Energy's jurisdictional scheme overs and unders account. We have set the revenue from jurisdictional charges to achieve a closing balance (for 2022/23) as close as possible to zero.

The amounts for 2021-22 are based on audited information lodged in our RIN.

[8] The scheme operates under clause 44A of the Electricity Act 1994 (Qld).

Table 12: Jurisdictional scheme amounts unders and overs account

Unders/overs account element	2021-22 Year t-2 (actual) $	2022-23 Year t-1 (estimate) $	2023-24 Year t (forecast) $
(A) Revenue from jurisdictional schemes	**$85,046,641**	**$65,486,666**	**$46,035,480**
(B) Less jurisdictional scheme payments for regulatory year =	**$73,683,642**	**$68,583,800**	**$65,926,489**
+ SBS amount	$73,572,141	$68,302,053	$65,530,342
+ AEMC amount	$111,501	$281,748	$396,147
(A minus B) Under/over recovery of revenue for regulatory year	**$11,362,999**	**-$3,097,134**	**-$19,891,010**
Jurisdictional scheme amount unders and overs account			
Nominal WACC (per cent)	3.123%	5.755%	10.266%
Opening balance	$9,100,090	$20,923,331	$18,942,449
Interest on opening balance	$284,181	$1,204,125	$1,944,621
Under/over recovery of revenue for regulatory year	$11,362,999	-$3,097,134	-$19,891,010
Interest on under/over recovery for regulatory year	$176,060	-$87,873	-$996,061
Closing balance	**$20,923,331**	**$18,942,449**	**($0)**

3.5 Forecast customer numbers, energy and demand

Calculating our network prices requires that we forecast customer numbers, energy consumption and network demand. Our network demand, energy and customer number forecasting methodologies are set out in our 2021 to 2026 Distribution Annual Planning Report[9]. Energy forecasts are prepared at the total network level, at customer category levels and for certain individually calculated network tariffs.

Energy and maximum demand forecasts for major ICC and CAC customers are individually developed. The energy forecast is based on a review of each customer's recent actual consumption history plus any confirmed future operational changes. The forecast demand is either:

- negotiated with the network user and detailed in their connection contract ('contracted demand'), or
- based on a review of actual demand history with adjustments reflecting up to date customer related information about additions or losses of load.

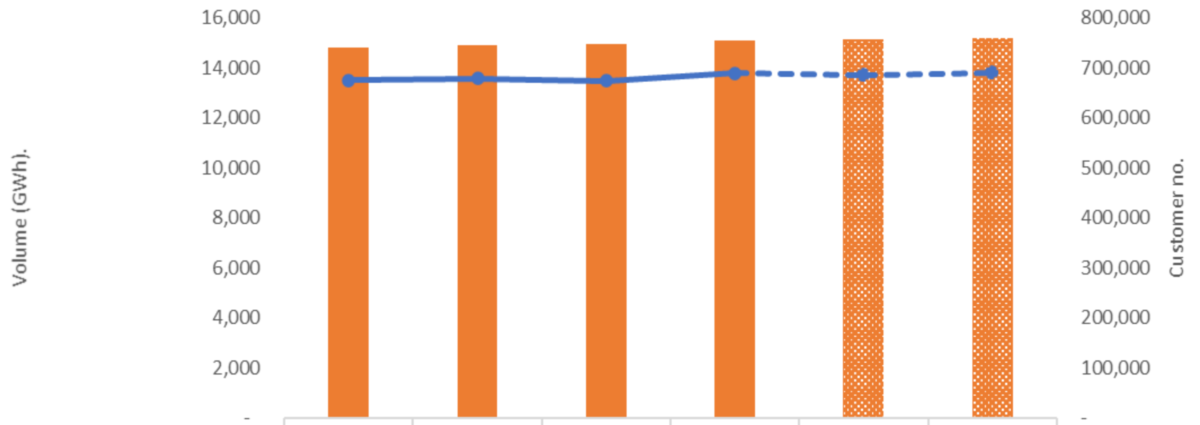
For new ICC and CAC customers, a flat usage or similar industry load profile is applied as appropriate until historical data for their connection is available.

For the SAC network user group, forecast energy consumption and customer numbers are based on a combination of econometric forecasts and trend extrapolation.

The forecast energy consumption and customer numbers used for the 2022-23 Pricing Proposal are included in Table 13.

[9] https://www.ergon.com.au/network/network-management/future-investment/distribution-annual-planning-report

Table 13: Actual, estimate and forecast energy consumption and customer numbers[10]



	2018-19 Actual	2019-20 Actual	2020-21 Actual	2021-22 Actual	2022-23 Estimate	2023-24 Forecast
Customer numbers	740,365	745,040	748,827	755,918	756,278	759,269
Energy delivered (GWh)	13,504	13,567	13,477	13,780	13,708	13,804

To the extent that actual volumes deviate from forecast, the revenue cap form of control mechanism will result in future network prices needing to be adjusted to account for the under or over recovery of network revenue. We endeavour to make sure that any adjustments to prices as a consequence of the operation of the revenue cap does not result in unacceptable customer impacts or create unnecessary pricing uncertainty and volatility.

3.6 Consideration of customer impacts

Our TSS describes the measures we have taken to manage the impact of annual change to DUOS rates on individual customers, whilst moving toward a greater cost reflectivity over the 2021 to 2025 period. These measures include:

- Progressively transitioning the LRMC components of charges towards full LRMC recovery and making small adjustments to the comparative attractiveness of the tariff options available to customers.
- Providing optional time-of-use energy tariffs to SAC Small customers who do not wish to be on a demand tariff.
- Granting a 12-month grace period for existing residential and small business customers that receive a smart meter due to end-of-life reasons before they are re-assigned to the cost reflective transitional demand tariffs.

In establishing the 2023-24 tariffs, we have continued to apply these measures.

[10] The volume number presented in this table is the anytime forecast volume (both billable and unbillable) which may deviate from the billable volumes depending on the individual uptake of network tariff structures.

Table below presents our customer impact analysis for SAC customers for 2023-24. Residential and small business customers on cost-reflective tariffs are expected to experience a decrease up to 9.6%, in their NUOS charges in 2023-24 compared with their 2022-23 charges.

This change is driven by:

- a decrease in our distribution revenue
- an increase in Powerlink's transmission charges and
- a decrease in jurisdictional scheme amounts that we are required to recover.

Table 14: Customer impact for average customers on SAC tariffs - Nominal ($) – NUOS change

East pricing zone

SAC Tariffs		Demand (kW or kVA/month)	Usage (kWh/year)	2022-23 NUOS Nom ($)	2023-24 NUOS Nom ($)	Annual NUOS change ($)	Annual NUOS change (%)
Residential (<100MWh pa) - East							
ERTDEMT1	Residential Transitional Demand East T1	3.20	5,478	873.86	851.78	-22.08	-2.5%
ERDEMT1	Residential Demand East T1	3.20	5,478	869.75	846.90	-22.85	-2.6%
ERTOUET1	Residential ToU Energy East T1	N/A	5,478	1,030.82	1,007.26	-23.55	-2.3%
ERIBT1	Residential IBT East T1*	N/A	5,478	982.82	975.11	-7.71	-0.8%
*Grandfathered							
Small Business (<100MWh pa) - East							
EBTDEMT1	Small Business Transitional Demand East T1	7.36	14,774	1,753.78	1,726.28	-27.51	-1.6%
EBDEMT1	Small Business Demand East T1	7.36	14,774	1,975.30	1,946.87	-28.43	-1.4%
EBTOUET1	Small Business ToU Energy East T1	N/A	14,774	1,928.13	1,901.52	-26.60	-1.4%
EBIBT1	Small Business IBT East T1*	N/A	14,774	2,193.67	2,185.33	-8.34	-0.4%
EBWIFT1	Small Business Wide Inclining Fixed East T1	N/A	14,774	2,444.29	2,423.36	-20.93	-0.9%
EBPLCT1	Small Business Primary Load Control	N/A	14,774	1,212.68	1,189.37	-23.31	-1.9%
*Grandfathered							
Large (>100MWh pa) - East							
EBESTT1	Large Business Energy East 1	N/A	102,158	19,528.76	20,275.03	746.26	3.8%
EDSTT1	Demand Small East T1 kVA	33.36	224,234	29,692.83	31,126.50	1,433.68	4.8%
EDMTT1	Demand Medium East T1 kVA	98.19	812,930	90,723.31	95,046.79	4,323.48	4.8%
EDLTT1	Demand Large East T1 kVA	126.78	1,745,919	189,323.14	194,361.43	5,038.29	2.7%
ELTOUDT1	Large Business Time-of-Use Demand East T1	300.56	651,648	117,685.38	121,904.44	4,219.05	3.6%
ESTOUDT1	Seasonal Time-of-Use Demand East T1*	88.54	411,613	55,225.97	59,351.74	4,125.78	7.5%

*Grandfathered kW demand

West pricing zone

SAC Tariffs		Demand (kW or kVA/month)	Usage (kWh/year)	2022-23 NUOS Nom ($)	2023-24 NUOS Nom ($)	Annual NUOS change ($)	Annual NUOS change (%)
Residential (<100MWh pa) - West							
WRTDEMT1	Residential Transitional Demand West T1	3.20	5,478	2,157.05	2,060.93	-96.11	-4.5%
WRDEMT1	Residential Demand West T1	3.20	5,478	2,262.90	2,159.01	-103.89	-4.6%
WRTOUET1	Residential ToU Energy West T1	N/A	5,478	2,776.92	2,651.24	-125.68	-4.5%
WRIBT1	Residential IBT West T1*	N/A	5,478	2,576.54	2,525.44	-51.11	-2.0%
*Grandfathered							
Small Business (<100MWh pa) - West							
WBTDEMT1	Small Business Transitional Demand West T1	7.36	14,774	4,628.28	4,420.37	-207.91	-4.5%
WBDEMT1	Small Business Demand West T1	7.36	14,774	5,123.91	4,893.23	-230.67	-4.5%
WBTOUET1	Small Business ToU Energy West T1	N/A	14,774	5,181.37	4,976.27	-205.10	-4.0%
WBIBT1	Small Business IBT West T1*	N/A	14,774	5,395.24	5,280.06	-115.18	-2.1%
WBWIFT1	Small Business Wide Inclining Fixed West T1	N/A	14,774	8,876.31	8,713.92	-162.39	-1.8%
WBPLCT1	Small Business Primary Load Control	N/A	14,774	2,031.15	1,954.32	-76.83	-3.8%
*Grandfathered							
Large (>100MWh pa) - West							
WBESTT1	Large Business Energy West T1	N/A	161,814	54,550.22	55,105.42	555.19	1.0%
WDSTT1	Demand Small West T1 kVA	33.07	214,573	72,584.57	74,330.86	1,746.29	2.4%
WDMTT1	Demand Medium West T1 kVA	58.98	511,636	180,758.15	181,648.97	890.82	0.5%
WDLTT1	Demand Large West T1 kVA	61.69	1,248,190	449,379.66	444,814.56	-4,565.10	-1.0%
WLTOUDT1	Large Business Time-of-Use Demand West T1	24.36	75,895	225,478.41	224,508.69	-969.72	-0.4%
WSTOUDT1	Seasonal Time-of-Use Demand West T1*	53.36	302,173	102,106.03	108,892.84	6,786.81	6.6%

*Grandfathered kW demand

Mount Isa

SAC Tariffs		Demand (kW or kVA/month)	Usage (kWh/year)	2022-23 NUOS Nom ($)	2023-24 NUOS Nom ($)	Annual NUOS change ($)	Annual NUOS change (%)
Residential (<100MWh pa) - Mt Isa							
MRTDEMT4	Residential Transitional Demand Mt Isa T4	3.20	5,478	795.20	781.03	-14.17	-1.8%
MRDEMT4	Residential Demand Mt Isa T4	3.20	5,478	836.50	826.20	-10.31	-1.2%
MRTOUET4	Residential ToU Energy Mt Isa T4	N/A	5,478	895.66	882.24	-13.41	-1.5%
MRIBT4	Residential IBT Mt Isa T4*	N/A	5,478	838.11	829.14	-8.97	-1.1%
*Grandfathered							
Small Business (<100MWh pa) - Mt Isa							
MBTDEMT4	Small Business Transitional Demand Mt Isa T4	7.36	14,774	1,481.54	1,462.86	-18.68	-1.3%
MBDEMT4	Small Business Demand Mt Isa T4	7.36	14,774	1,862.78	1,832.72	-30.06	-1.6%
MBTOUET4	Small Business ToU Energy Mt Isa T4	N/A	14,774	1,580.43	1,563.27	-17.16	-1.1%
MBIBT4	Small Business IBT Mt Isa T4*	N/A	6,309	1,036.58	1,030.26	-6.32	-0.6%
MBWIFT4	Small Business Wide Inclining Fixed Mt Isa T4	N/A	36,223	4,710.56	4,731.83	21.27	0.5%
MBPLCT4	Small Business Primary Load Control	N/A	14,774	1,112.10	1,105.67	-6.42	-0.6%
*Grandfathered							
Large Business (>100MWh pa) - Mt Isa							
MBESTT4	Large Business Energy Mt Isa T4	N/A	232,097	19,683.27	18,918.85	-764.42	-3.9%
MDSTT4	Demand Small Mt Isa T4 kVA	27.62	176,435	16,869.57	16,315.31	-554.26	-3.3%
MDMTT4	Demand Medium Mt Isa T4 kVA	27.96	537,672	41,657.79	40,411.83	-1,245.95	-3.0%
MDLTT4	Demand Large Mt Isa T4 kVA	98.56	1,784,023	120,731.64	117,683.30	-3,048.34	-2.5%
MLTOUDT4	Large Business Time-of-Use Demand Mt Isa T4	300.56	651,648	86,141.72	84,038.56	-2,103.15	-2.4%
MSTOUDT4	Seasonal Time-of-Use Demand Mt Isa T4*	74.50	580,971	41,209.28	40,561.71	-647.57	-1.6%

*Grandfathered kW demand

As ICC and CAC tariffs are confidential, we are not able to include a customer specific impact analysis. However, general trends in ICC and CAC customer impacts between 2022-23 and 2023-24 are presented below.

Table 15: Average customer impacts for the ICC and CAC tariff classes

Tariff Class	Impact	DUOS annual impact (%)	NUOS annual impact (%)
CAC	Average Impact	-2.36%	0.62%
ICC	Average Impact	-1.03%	-2.18%

Notes:Impacts based on forecast quantities t applied to rates t-1 and t.

The prices used for the customer impact analysis are the AER approved prices for 2022-23 and the proposed 2023-24 prices. To eliminate the impact of fluctuation in demand and energy between years, the same usage and demand profiles were used to calculate customers' bills for both 2022-23 and 2023-24.

3.7 Trial tariffs

Ergon Energy intends to undertake a trial of Time of Use export tariffs for High Voltage and Sub-Transmission Voltage customers in 2023-24.

The objective of this trial is to assess the ability of energy storage customers to respond to cost reflective price signals to support the electricity network in periods of low system demand and peak periods when the electricity network is more likely to be constrained. Insights and learnings from this tariff trial will help inform the design of Time of Use signals for high voltage customers which we intend to offer in the next regulatory control period.

Retailers can opt a high voltage customer in and out of the trial tariff at any time during 2023-24.

4. Alternative Control Services

Ergon Energy's Alternative Control Services are regulated under a price cap control mechanism. This means that the AER determines our efficient costs and approves a maximum price that we can charge for the service. Our TSS sets out the methodology we follow to establish our prices for Alternative Control Services including how we apply the control mechanism formulae set out in the Distribution Determination - Attachment 13.

The proposed 2023-24 prices for Alternative Control Services tariffs are provided in Attachment 1 to our Pricing Proposal.

4.1 Tariff classes

Our tariff classes for Alternative Control Services are differentiated at the highest level according to the classification of services approved in the AER's Distribution Determination. Our Alternative Control Services tariff classes are set out below.

Table 16: Alternative Control Services tariff classes

Tariff class	Services
Connection services	Services relating to the electrical or physical connection of a customer to the network including: • Major customer premises connections • Major customer network extensions • Connection application and management services: o Connection application related services o De-energisation and re-energisation services o Temporary connections o Temporary disconnection and re-connections o Supply abolishment o Remove or reposition connections o Overhead service line replacements o Protection and power quality assessments o Customer requested change requiring secondary and primary plant studies for safe operation of the network o Upgrade from overhead to underground services o Rectification of illegal connection or damage to service cables o Supply enhancements o Power factor corrections • Enhanced connection services
Metering services	• Type 6 default metering services • Auxiliary metering services including: o Meter inspection and investigation o Meter reconfiguration o Meter alteration o Reseal o Meter test o Meter reading o Removal of meter (Type 6) o Type 6 non-standard metering data services
Public lighting services	• Public lighting services • Auxiliary public lighting services including: o Construction of new public light services o Provision of unique luminaire glare screening o Relocation, rearrangement or removal of existing public light assets o Exit fee for the residual asset value of non-contributed public lights when the entire assets are replaced before the end of their expected life o Emerging public lighting services

Tariff class	Services
Network ancillary services	Customer and third party-initiated services related to the common distribution including: • Network safety services - Provision of traffic control and safety observer services, Fitting of tiger tails and aerial markers, De-energising for safety, High load escorts • Customer requested planned interruptions • Attendance at customers' premises to perform a statutory right • Customer, retailer or third party requested appointments • Removal/re-arrangement of network assets • Network related property services • Authorisation and approval of third-party service providers design and works • Inspection and auditing services • Sale of approved materials or equipment • Provision of training to third parties for network related access • Security (watchmen) lights • Non-standard network data requests • Customer requested provision of electricity network data • Third party funded network alternations

4.2 Tariffs and charging parameters

Attachment 1 sets out the proposed tariffs for Alternative Control Services which have been specified in our TSS. The pricing arrangements utilised to calculate the charges for Alternative Control Services are presented in Table 17.

Table 17: Pricing arrangements for Alternative Control Services

Tariff classes and Services	Pricing arrangements	Charging parameter
Connection services – Services relating to the electrical or physical connection of a customer to the network		
Major customer - Premises connections	Quoted price	Quoted rate ($) per service. The quoted price varies according to the requested service and actual resources required to deliver the service.
Major customer - Network extensions	Quoted price	Quoted rate ($) per service. The quoted price varies according to the requested service and actual resources required to deliver the service.
Connection application and management services	Fixed charge and in some cases Quoted price	Fixed rate ($) per service. The rate varies depending on the service requested. Quoted rate ($) per service. The quoted price varies according to the requested service and actual resources required to deliver the service.
Enhanced connection services	Quoted price	Quoted rate ($) per service. The quoted price varies according to the requested service and actual resources required to deliver the service.
Network ancillary services – Customer and third party-initiated services related to the common distribution service		
Network safety services	Quoted price	Quoted rate ($) per service. The quoted price varies according to the requested service and actual resources required to deliver the service.
Customer requested planned interruptions	Quoted price	Quoted rate ($) per service. The quoted price varies according to the requested service and actual resources required to deliver the service.
Attendance at customers' premises to perform a statutory right	Fixed charge	Fixed rate ($) per service. The rate varies depending on the service requested.

Tariff classes and Services	Pricing arrangements	Charging parameter
Customer, retailer or third party requested appointments	Quoted price	Quoted rate ($) per service. The quoted price varies according to the requested service and actual resources required to deliver the service.
Removal/rearrangement of network assets	Quoted price	Quoted rate ($) per service. The quoted price varies according to the requested service and actual resources required to deliver the service.
Network related property services	Quoted price	Quoted rate ($) per service. The quoted price varies according to the requested service and actual resources required to deliver the service.
Authorisation and approval of third-party service providers design/ works	Quoted price	Quoted rate ($) per service. The quoted price varies according to the requested service and actual resources required to deliver the service.
Inspection and auditing services	Quoted price	Quoted rate ($) per service. The quoted price varies according to the requested service and actual resources required to deliver the service.
Sale of approved materials or equipment	Quoted price	Quoted rate ($) per service. The quoted price varies according to the requested service and actual resources required to deliver the service.
Provision of training to third parties for network related access	Quoted price	Quoted rate ($) per service. The quoted price varies according to the requested service and actual resources required to deliver the service.
Security (watchman) lights	Quoted price - for installation service costs Fixed charge - for the maintenance, operation and replacement of the assets	Quoted rate ($) per service. The quoted price varies according to the requested service and actual resources required to deliver the service. Fixed rate ($) per day per light - Within the tariff structure, daily charges differ by: • light type (conventional or LED) and • the size of the lamp/luminaire.
Non-standard network data requests	Quoted price	Quoted rate ($) per service. The quoted price varies according to the requested service and actual resources required to deliver the service.
Customer requested provision of electricity network data	Quoted price	Quoted rate ($) per service. The quoted price varies according to the requested service and actual resources required to deliver the service.
Third party funded network alternations	Quoted price	Quoted rate ($) per service. The quoted price varies according to the requested service and actual resources required to deliver the service.
Metering services		
Type 6 default metering services	Fixed price	Metering services charge: fixed ($) per day per tariff. Metering service charges differ by: • The type of metering service (primary, controlled load, solar PV), and • The type of cost recovery (capital, non-capital).
Auxiliary metering services	Fixed price, and in some cases Quoted price	Fixed rate ($) per service. The rate varies depending on the service requested. Quoted rate ($) per service. The quoted price varies according to the requested service and actual resources required to deliver the service.
Public Lighting Services		
Public lighting services	Fixed price	Public lighting charge: Fixed rate ($) per day per light. Daily public lighting charges differ by: • the ownership status (owned and operated, or Gifted and operated),

Tariff classes and Services	Pricing arrangements	Charging parameter
		• the size of the lamp (major or minor), and • technology (conventional vs LED).
Auxiliary public lighting services	Quoted price	Quoted rate ($) per service. The quoted price varies according to the requested service and actual resources required to deliver the service.

4.3 Tariffs assignment process

For ACS, customers or customers' retailers self-assign to a tariff class when requesting the service they require. In accordance with our TSS, we generally do not initiate tariff class re-assignments for ACS. However, there are some circumstances where a field crew attends a site, and the scope of work does not match the service order or work request. This may mean a different service type and/or tariff class may be more appropriate. In these instances, the job is generally returned as not completed and a new service order or work request would need to be submitted. Consequently, a new tariff class assignment, rather than reassignment, would occur.

4.4 Pricing methodology

4.4.1 Type 6 default metering services

For our Type 6 Default Metering Services, we have applied a limited building block approach to determine the revenue required over 2020-25 regulatory control period. This allowable revenue is then converted into metering service charges that are each subject to a price cap for the regulatory control period.

In years 2 to 5 of the regulatory control period (2021-2025), the prices are adjusted for inflation and the X factor.

In accordance with our TSS for the 2020-25 regulatory control period Type 6 default metering services include maintenance, reading, data services, and the recovery of capital costs related to Type 6 meters. Type 6 default metering service charges are applied through a daily metering services charge. These charges are split into two components:

- a non-capital (operating expenditure) component that is applied to customers with legacy Type 6 meters and continues to apply until a customer's meter is replaced with an unregulated Type 1-4 meter.
- a capital component that is applied to customers connected prior to 1 July 2015, to recover the remaining capital cost related to legacy Type 6 meters. This charge will continue to apply until the depletion of Ergon Energy's remaining metering asset base.

Consistent with our TSS, we apply the following types of Type 6 default metering charges to recover the annual revenue requirement from customers:

- A metering service charge for the primary metering service
- A supplementary charge for each secondary controlled load, and
- A supplementary charge for solar PV.

Table 18: Type 6 Default Metering Service tariffs

Tariff group	Tariffs	Charging parameters
Primary tariff	Non-capital	Fixed rate ($) per day

Tariff group	Tariffs	Charging parameters
	Capital	
Load control	Non-capital	
	Capital	
Solar PV	Non-capital	
	Capital	

4.4.2 Public lighting services

For public lighting services, the limited building block approach is used to determine our revenue requirements during 2020-25. This allowable revenue is then converted into public lighting service charges that are each subject to a price cap for the regulatory control period.

In years 2 to 5 of the regulatory control period (2021-2025), the prices are adjusted for inflation and the X factor.

In accordance with our TSS for the 2020-25 regulatory control period, Network Public Lighting (NPL) charges reflect whether:

- The public lighting services are located on minor or major roads
- The assets have been funded by us or by the customer i.e. NPL1 “Ergon Energy owned and operated” versus NPL2 “customer gifted and operated by Ergon Energy”, NPL4 for assets where customers fund the replacement of the NPL1 luminaire and lamp to LED, but where the associated pole and cabling are legacy and non-contributed assets, and
- The type of public lighting technology (i.e. conventional or LED).

The public lighting tariffs offered in 2022-23 are set out in the table below.

Table 19: Public lighting tariffs

Tariff group	Conventional Lights tariffs	LED specific tariffs	Charging parameters
NPL1 - Minor	NPL1C Minor – funded by Ergon Energy	NPL1L Minor – Funded by Ergon Energy	Fixed rate ($) per day per light
NPL1 - Major	NPL1C Major – funded by Ergon Energy	NPL1L Major – Funded by Ergon Energy	
NPL2 - Minor	NPL2C Minor – Funded by Council	NPL2L Minor – Funded by Councils	
NPL2 - Major	NPL2C Major – Funded by Council and DTMR	NPL2L Major – Funded by Councils and DTMR	
NPL4 - Minor	N/A	NPL4 Minor – Funded by Councils	
NPL4 - Major	N/A	NPL4 Major – Funded by Councils	

4.4.3 Other Alternative Control Services

In accordance with the AER's Determination Decision, a cost build up approach was used to determine the prices for all other services classified as ACS. Pricing arrangements for these services are either fee-based or quoted depending on the type of service.

Fee-based services

The prices for fee-based services are set in accordance with specified service assumptions due to the standardised nature of the services. Fee-based services are determined via a cost build up approach at the individual service level and relate to activities undertaken by us at the request of customers or their agents. The costs for these activities can be directly attributed to customers and service-specific prices can be charged.

During the first year of the regulatory control period (i.e. 2020-21), the prices for fee-based services are determined using the AER's approved cost build-up formula. In years 2 to 5 of the regulatory control period (2021-2025), the prices are adjusted annually for inflation and the X factor.

Quoted services

Prices for quoted services are determined at the time the customer makes an enquiry and therefore reflect the individual nature and scope of the requested service which cannot be known in advance. The indicative prices for quoted services are determined using the AER's approved price cap formula below.

Equation 1: Price cap formula for quoted services

Price = Labour + Contractor Services + Materials

Where:

- Labour (including on costs and overheads) - consists of all labour costs directly incurred in the provision of the service which may include, but is not limited to, labour on costs and overheads. The labour cost for each service is dependent on the skill level and experience of the employee/s, time of day/week in which the service is undertaken, travel time, number of hours, number of site visits and crew size required to perform the service.
- Contractor services (including overheads) - reflects all costs associated with the use of external labour in the provision of the service, including overheads and any direct costs incurred as part of performing the service.
- Materials (including on costs and overheads) - reflects the cost of materials directly incurred in the provision of the service, material storage and logistics on costs and overheads.

4.5 Annual cost input changes

In accordance with the AER's Distribution Determination, the annual changes to cost inputs used in calculating prices for our Alternative Control Services are required to be submitted to the AER for approval in our Pricing Proposal. The CPI and X factors used for setting 2023-24 prices are provided in Attachment 4 (2023-24 annual ACS Pricing Model).

5. Comparison of 2023-24 proposed and indicative prices

The NER requires us to demonstrate how each proposed tariff is consistent with the indicative pricing levels (as set out in the indicative pricing schedule) and explain material differences. A comparison between the proposed prices for 2023-24 and the indicative prices submitted with our 2022-23 Pricing Proposal submission is provided in the annual SCS and ACS pricing models. Further explanation is provided below.

5.1 Differences in Standard Control Services pricing levels

Deviations from the indicative prices for 2023-24 are due to:

- updates to allowed revenue to reflect actual 2021-22 revenue and estimated revenue for 2022-23
- updates to approved jurisdictional scheme amounts (Solar Bonus Scheme and AEMC levy) and DPPC amounts based on the latest forecasts
- updates of forecast customer numbers, energy consumption and demand.

Any variations from indicative prices which are above five percent are highlighted and explained in the annual SAC pricing model (Attachment 3).

5.2 Differences in Alternative Control Services pricing levels

Any differences between the indicative 2023-24 prices for Alternative Control Services (included in the 2022-23 Pricing Proposal submission) and the 2023-24 prices included in this Pricing Proposal are reflective of the difference between the forecast CPI and actual CPI.

5.3 Updated indicative prices for the remainder of the regulatory period

The indicative prices for the remainder of the regulatory control period (2024-25) are provided in Attachment 2 of our Pricing Proposal, as well as Attachments 3 and 4 (annual SCS and ACS pricing models).

6. Changes from the previous regulatory year

The NER requires us to describe the nature and extent of change from the previous regulatory year and demonstrate that the changes comply with the NER and any applicable distribution determination.

We do not propose to make any variations to the structure of network tariffs or tariff assignment rules during 2023-24. Further, there are no changes from the previous regulatory year in any aspects of our 2023-24 proposal for Alternative Control Services.

7. Variations to tariffs within the regulatory year

The NER requires that a pricing proposal sets out the nature of any variations or adjustments to the tariff that could occur during the course of the regulatory year and the basis on which it could occur.

7.1 Standard Control Services tariff adjustments

We propose to adjust our ICC network tariffs in circumstances where an ICC customer advises us that they intend to alter their demand or connection characteristics during the course of the year. In these circumstances, we will recalculate the customer's site-specific charge with the adjustment applied to the fixed, capacity, demand and volume charging parameters for ICC customers.

In accordance with our TSS, these adjustments are required to ensure these tariffs remain cost reflective. Any changes in site-specific charges for ICC customers will occur at the next network bill.

When new tariffs are created for new ICC connections during 2023-24, the price setting mechanism will be in line with the methodology set out in our TSS and this Pricing Proposal with the rates reflecting the customer's connection characteristics and the specifically identified portion of the shared distribution network utilised for the electricity supply.

There are no other variations or adjustments proposed to be made to Standard Control Services tariffs during the 2023-24 regulatory year.

7.2 Alternative Control Services tariff adjustments

With the exception of the application of Schedule 8 of the *Electricity Regulation 2006* to a number of our fee-based Alternative Control Services, there are no other variations or adjustments proposed to be made to Alternative Control Services tariffs during the 2023-24 regulatory year.

8. Consistency with the TSS

This section provides our responses to the additional requirements set out in the AER's final determination on our 2020-25 TSS.

8.1 Consistency with price constraints

Our TSS includes price control constraints for our SAC tariffs designed to limit customer impact while progressing tariff reform. In establishing the 2022-23 tariffs, we have taken these into account to achieve sustainable pricing outcomes. Specifically, we are targeting a larger increase in revenue from legacy tariffs, while minimising changes in rates for our cost reflective tariffs, in order to maintain the tariff relativities outlined in our TSS.

Further, for our legacy residential and small business IBT tariffs, we have progressed the strategy outlined in our 2021-22 Pricing proposal, with block 3 and block 2 energy consumption (volume) rates set equal, in order to prepare for simplification of the IBT tariff structures post 2025.

Three optional transitional tariffs were introduced for existing SAC Small business customers in the East pricing zone who have been on a revoked retail transitional tariff at some point in the period 1 July 2017 to 30 June 2020. A price path outlined our 2021-22 Pricing proposal has been applied to these tariffs. We note that there are currently no customers on these tariffs. Being transitional in nature, we propose that these grandfathered tariffs are retired at the end of the current regulatory control period (i.e. post 2024-25).

8.2 ICC price setting methodology

The AER's final determination on the 2020-25 TSS requires Ergon Energy to include a detailed description of the approach to setting the ICC tariffs in our annual pricing proposals.

Ergon Energy's methodology for setting the price level of the ICC tariffs is designed to price the provision of electricity services in the most equitable and efficient manner possible. The equity outcomes under this methodology are achieved by allocating residual costs to site-specific connections in a manner that reflects their utilisation of the assets involved in the provision of network services. Favourable customer outcomes are also realised by transitioning the level of ICC tariffs where it is necessary to do so for customer impact considerations.[11] The superior economic efficiency outcomes associated with the ICC tariffs are achieved mainly by these customers receiving the pass through of Powerlink's transmission charges. This creates an important economic incentive for new ICC customers to locate in areas of the network that have a low cost to serve from a transmission perspective.

In contrast to the published tariffs, the ICC tariffs are also capable of signalling economic costs in a manner that more accurately reflect localised economic conditions.[12] The extent to which it is appropriate to signal economic costs to this degree is dependent upon a range of considerations, such as the nature of these economic conditions, the responsiveness of customers to price signals, the impact on customers as well as the transaction costs associated with developing more refined price signals.

A detailed description of each component of the ICC price-setting methodology is provided below.

[11] Refer to Clause 6.18.5(h) of the NER.
[12] Refer to Clause 6.18.5(f) of the NER.

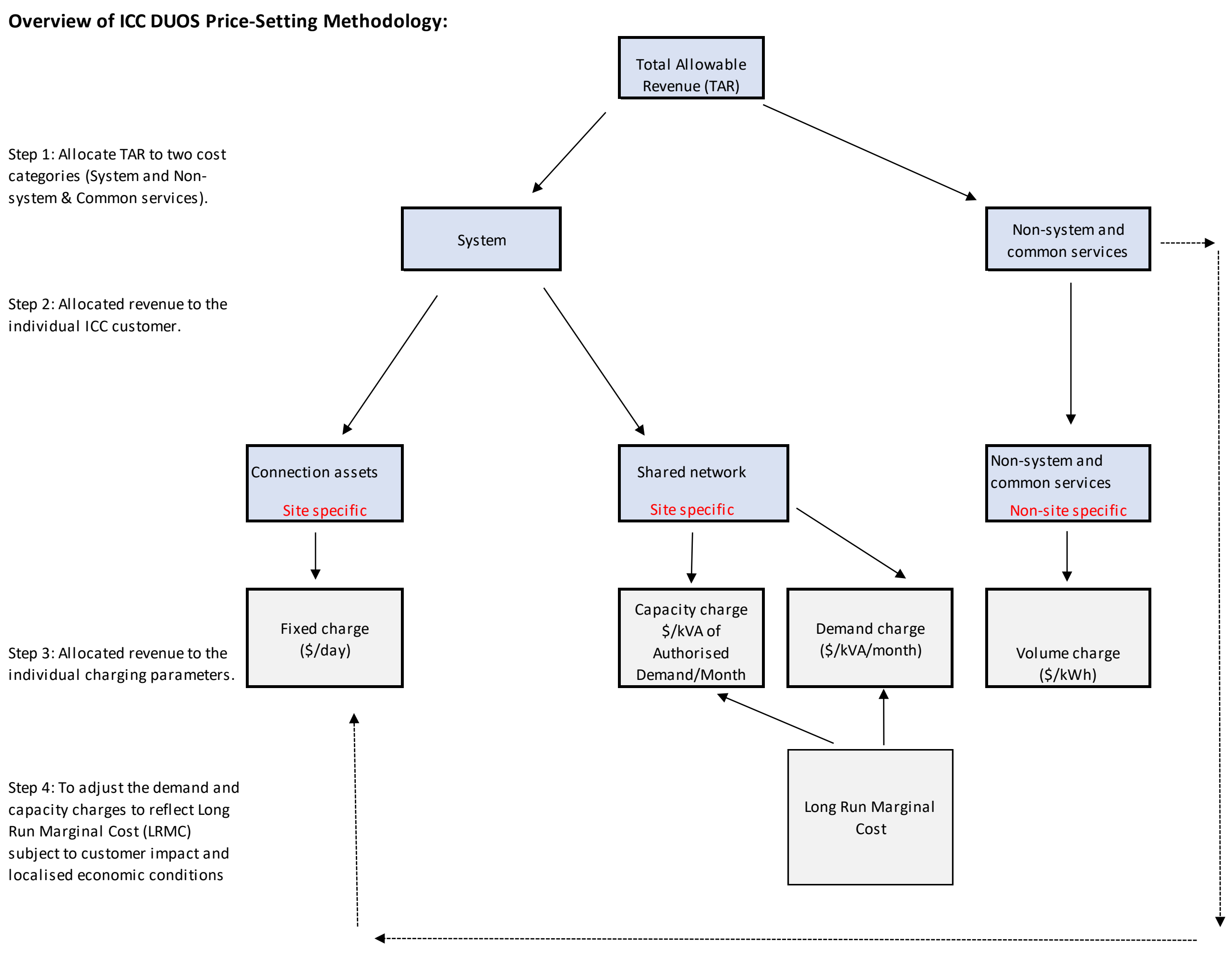
DUOS price setting methodology

Ergon Energy's methodology for setting the DUOS prices for ICC customers is comprised of the following steps.

1. The distribution cost to serve for each ICC customer is calculated by allocating the TAR for standard control distribution services into system and non-system components.[13]
2. These costs are then allocated into site-specific cost elements (i.e. connection and shared) and non-site specific cost elements (i.e. common and non-system).
3. The distribution cost to serve for an ICC customer is then allocated into each of the individual charging parameters.
4. The tariff calculated In Step 3 is adjusted to determine the extent that is appropriate to signal LRMC cost through the demand charge which is evaluated on the basis of customer impact the extent that customers are expected to respond to marginal price signals given the nature of their usage and the expected benefits from doing so given the nature of localised network conditions.

An overview of this methodology is provided in Figure 3: DUOS cost allocation for ICCs.

Figure 3: DUOS cost allocation for ICCs



[13] System costs are the directly attributable costs associated with the provision of network connection and distribution services. Non-system costs include items such as corporate support that are not directly attributable to the operation and maintenance of the network but are associated with network service delivery.

DPPC price setting methodology

DPPC charges for ICC customers are site specific and based on the charges which Powerlink charges Ergon Energy at the Bulk Supply Point at which the customer is connected. The methodology to convert Powerlink's charges to DPPC charges is summarised in the table below.

Table 20: DPPC charging parameters

Powerlink charges	Methodology to convert Powerlink's charge to DPPC charge	Corresponding DPPC charging parameter	Application
Entry/Exit connection charge ($'000/month)	Entry/Exit connection charge is apportioned to ICC customers using customers individual monthly peak demand (kW) and the total demand supplied through that Bulk Supply Point	Fixed charge ($/day)	Site and customer specific price
Locational charge ($/kW/month)	This charge is a direct pass-through	Locational charge ($/kW/month)	DPPC charge applied to individual ICC forecast monthly peak demand kW
General energy charge (c/kWh)	This charge is a direct pass-through	General services charge ($/kWh)	DPPC charge applied to individual ICC forecast annual energy (kWh)
Common service energy charge (c/kWh)	This charge is a direct pass-through	Common services charge ($/kWh)	DPPC charge applied to individual ICC forecast annual energy(kWh)

Jurisdictional Scheme price setting methodology

Jurisdictional Scheme (JS) charges for ICC customers are not site specific i.e. the same Fixed ($/day) and Volume ($/kWh) charge applies to all ICC customers.

Step 1: JS revenue allocation

To allocate an ICCs JS revenue, the default is the same for all network tariff classes being a proportion of the total JS revenue using customer numbers and energy.

Step 2: The JS allocation is then converted to rates

These rates are not site specific so the same JS Fixed and Volume charge applies to all ICCs. The rates are struck using the sum of individual ICCs numbers and forecast annual energy. The split of allocation between Fixed and Volume charges is done by tariff group.

Update on Non-standard ICC tariffs

In accordance with the requirements in our TSS, Ergon Energy introduced optional non-standard ICC tariffs on 1 July 2021. These tariffs were only available to existing CAC customers on an obsolete retail transitional tariff set out by the Queensland Commission Authority (QCA). To apply for access to the non-standard ICC tariff, re-assignment applications were required to be submitted to Ergon Energy by 30 June 2021.

Two customers applications were received, assessed, and deemed eligible for reassignment to the non-standard ICC tariff. As this tariff was designed to provide customers with a transitional path to cost reflectivity, an adjustment was made to the demand and capacity charging parameters for these customers. A five year price path (i.e. to 2026-27) has been set for the purpose of transitioning the LRMC price signal by discounting the annual LRMC-based DUOS revenue attributed to the individual customer’s coupling point. At the end of this transition period, the customers on the non-standard ICC tariff are expected to be paying the full network cost to serve.

Appendix A: Compliance Checklist

Table 21: AER's annual pricing proposal statement of compliance

Rule reference	Rule requirement and assessment statement	T/F or n/a	Page / section	Additional comments
6.18.1C and **11.141.8**	**Sub-threshold tariffs** No later than four months before the start of a regulatory year (other than the first regulatory year of a regulatory control period), a Distribution Network Service Provider may notify the AER, affected retailers and Market Small Generation Aggregators and affected retail customers of a new proposed tariff (a relevant tariff) that is determined otherwise than in accordance with the Distribution Network Service Provider's current tariff structure statement, if both of the following are satisfied: (1) the Distribution Network Service Provider's forecast revenue from the relevant tariff during each regulatory year in which the tariff is to apply is no greater than 1 per cent of the Distribution Network Service Provider's annual revenue requirement for that regulatory year (the individual threshold); and (2) the Distribution Network Service Provider's forecast revenue from the relevant tariff, as well as from all other relevant tariffs, during each regulatory year in which those tariffs are to apply is no greater than 5 per cent of the Distribution Network Service Provider's annual revenue requirement for that regulatory year (the cumulative threshold).			
	Each sub-threshold tariff has a forecast revenue that is less than 1 per cent of the TAR, and all sub-threshold tariffs have a combined forecast revenue less than 5 per cent of TAR.	True		Refer to the standardised compliance model
6.18.2(b)	**Pricing proposals** A Pricing Proposal must:			
6.18.2(b)(2)	Set out the proposed tariffs for each tariff class that is specified in the Distribution Network Service Provider's tariff structure statement for the relevant regulatory control period;			Refer to Sections 2.1 and 2.2
	All tariffs remain in the same tariff class as the approved tariff structure statement (TSS).	True		
6.18.2(b)(3)	Set out, for each proposed tariff, the charging parameters and the elements of service to which each charging parameter relates;			Refer to Section 2.2
	All tariffs retain the same charging parameters as the approved TSS.	True		
6.18.2(b)(4)	Set out, for each tariff class related to standard control services, the expected weighted average revenue for the relevant regulatory year and also for the current regulatory year;			Refer to Section 3.2.3
	The expected weighted average revenue for each tariff class is provided for the current and forecast years.	True		
6.18.2(b)(5)	Set out the nature of any variation or adjustment to the tariff that could occur during the course of the regulatory year and the basis on which it could occur;			Refer to Section 7
	The information provided for this rule requirement has not	True		

Rule reference	Rule requirement and assessment statement	T/F or n/a	Page / section	Additional comments
	materially changed from the approved TSS (for the first pricing proposal of the regulatory period), or the previous pricing proposal (for subsequent pricing proposals).			
6.18.2(b)(6)	Set out how designated pricing proposal charges are to be passed on to customers and any adjustments to tariffs resulting from over or under recovery of those charges in the previous regulatory year;			Refer to Section 3.3
	The information provided for this rule requirement has not materially changed from the approved TSS and/or the previous pricing proposal.	True		
6.18.2(b)(6A)	Set out how jurisdictional scheme amounts for each approved jurisdictional scheme are to be passed on to customers and any adjustments to tariffs resulting from over or under recovery of those amounts;			Refer to Section 3.4
	The information provided against this rule requirement has not materially changed from the approved TSS and/or the previous pricing proposal.	True		
6.18.2(b)(6B)	Describe how each approved jurisdictional scheme that has been amended since the last jurisdictional scheme approval date meets the jurisdictional scheme eligibility criteria;			We confirm there have been no changes to the jurisdictional schemes since the previous pricing proposal
	Jurisdictional schemes are unchanged since the previous pricing proposal.	True		
6.18.2(b)(6C)	Set out how system strength charges for system strength connection points on its network are to be passed through as described in clause 6.20.3A;			Powerlink's prices do not include any system strength charges for 2023-24, therefore Ergon Energy is not proposing to pass through any system strength charges
	The information provided for this rule requirement has not materially changed from the approved TSS and/or the previous pricing proposal.	N/A		
6.18.2(b)(7)	Demonstrate compliance with the Rules and any applicable distribution determination, including the Distribution Network Service Provider's tariff structure statement for the relevant regulatory control period;			This table and this Pricing Proposal (including attachments to this Pricing Proposal) demonstrates how Ergon Energy complies with the NER, the Distribution Determination and its TSS.
	The information provided for this rule requirement has not materially changed from the approved TSS and/or the previous pricing proposal.	True		
6.18.2(b)(7A)	Demonstrate how each proposed tariff is consistent with the corresponding indicative pricing levels for the relevant regulatory year as set out in the relevant indicative pricing schedule, or explain any material differences between them;			All variations are explained in the standardised compliance model
	Tariff prices are not materially different to the corresponding indicative prices.	False		
	If response to the previous question is false, the standardised compliance model/annual pricing proposal explains the source(s) for material changes in prices.	True		
6.18.2(b)(8)	Describe the nature and extent of change from the previous regulatory year and demonstrate that the changes comply with the Rules and any applicable distribution			Refer to Section 6

Rule reference	Rule requirement and assessment statement	T/F or n/a	Page / section	Additional comments
	determination.			
	There are no other material changes from the approved TSS (for the first pricing proposal of the regulatory period), or the previous pricing proposal (for subsequent pricing proposals) that should be brought to the attention of the AER.	True		
6.18.2(d)	**Indicative prices** At the same time as a Distribution Network Service Provider submits a pricing proposal under paragraph (a), the Distribution Network Service Provider must submit to the AER a revised indicative pricing schedule which sets out, for each tariff and for each of the remaining regulatory years of the regulatory control period, the indicative price levels determined in accordance with the Distribution Network Service Provider's tariff structure statement for that regulatory control period and updated so as to take into account that pricing proposal.			Attachment 2 to this pricing proposal also provides the revised indicative prices for the remaining regulatory years of the 2020-25 regulatory control period
	Revised indicative prices for tariffs are included in the standardised compliance model.	True		
6.18.2(e)	**Indicative prices for sub-threshold tariffs** Where the Distribution Network Service Provider submits an annual pricing proposal, the revised indicative pricing schedule referred to in paragraph (d) must also set out, for each relevant tariff under clause 6.18.1C, the indicative price levels for that relevant tariff for each of the remaining regulatory years of the regulatory control period, updated so as to take into account that pricing proposal.			The sub-threshold tariff trial proposed in this pricing proposal is for 2023-24 regulatory year and therefore not included in the indicative price schedule for the remaining regulatory years of the regulatory control period
	Revised indicative prices for sub-threshold tariffs are included in the standardised compliance model where applicable.	N/A		
6.18.5	**Pricing principles**			
6.18.5(e)	For each tariff class, the revenue expected to be recovered must lie on or between: (1) an upper bound representing the stand alone cost of serving the retail customers who belong to that class; and (2) a lower bound representing the avoidable cost of not serving those retail customers.			Refer to Section 3.2.5
	The information provided for this rule requirement has not materially changed from the approved TSS and is demonstrated in the standardised compliance model.	True		
6.18.5(g)(2)	The revenue expected to be recovered from each tariff must: when summed with the revenue expected to be received from all other tariffs, permit the Distribution Network Service Provider to recover the expected revenue for the relevant services in accordance with the applicable distribution determination for the Distribution Network Service Provider			Refer to the standardised compliance model
	The information provided for this rule requirement has not materially changed from the approved TSS and is demonstrated in the standardised compliance model.	True		

Appendix B: Glossary

Table 22: Acronyms, abbreviations and definitions

Term	Acronym	Definition
Alternative Control Service	ACS	Customer specific or customer requested services. These services may also have potential for provision on a competitive basis rather than by the local DNSP.
Anytime Maximum Demand	AMD	The demand for some network tariffs is calculated using ‘any-time’ demand. For these tariffs, the customers chargeable maximum demand is the highest 30 minute demand period regardless of when that occurs during the month.
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.
Business hours	BH	8 am to 5 pm, Monday to Friday.
Basic meter		Basic accumulation meters are defined as a meter that is only capable to recording the customers’ energy consumption during the billing period.
Capacity charge		A type of charge (charging parameter) included in network tariff structures. The capacity charge seeks to reflect the costs associated with providing network capacity required by a customer on a long term basis. It is levied on the basis of either contracted demand or forecasted capacity using prior year information.
Charging parameter		The charges comprising a tariff. Parameters include demand, capacity, fixed and volume (flat or time-of-use) charges.
Common service		A service that ensures the integrity of a distribution system, benefits all distribution customers and cannot reasonably be allocated on a locational basis.
Connection asset (Contributed or non-contributed)		Related to building connection assets at a customer’s premises as well as the connection of these assets to the distribution network. Connection assets can be contributed (customer funded, then gifted to Ergon Energy) or non-contributed (Ergon Energy funded).
Connection point		The agreed point of supply established between a Network Service Provider and another Registered Participant, Non-Registered Customer or franchise customer. The meter is installed as close as possible to this location.
Customer		Refer to chapter 10 of the NER.
Demand		The amount of electricity energy being consumed at a given time measured in either kilowatts (kW) or kilovolt amperes (kVA). The ratio between the two is the power factor.
Demand charge		A type of charge (charging parameter) included in network tariff structures. This charge accounts for the actual demand a customer places on the electricity network. Different parameters apply to this charged depending on the different tariffs.
Demand tariff		The tariff has been structured to include a demand component so the customer’s actual demand is reflected in the price they pay for their electricity.
Designated Pricing Proposal Charge	DPPC	Refers to the charges incurred for use of the transmission network; previously referred to as Transmission Use of System (TUOS).
Distribution Use of System	DUOS	This refers to the network charges which recover the costs of providing Standard Control Services.
Energy (or usage)		The amount of electricity consumed by a customer (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).
Feed-in Tariff	FiT	The rate that is to be paid for the excess energy generated by customers and fed back into the electricity grid under the Queensland Solar Bonus Scheme. The FiT

Term	Acronym	Definition
		rate is determined by the Queensland Government and is paid by the purchaser of the excess energy.
Fixed (or access) charge		A type of charge (charging parameter) included in network tariff structures which is levied on a fixed dollar amount per day.
High Voltage	HV	Refers to the network at 11 kV or above.
Large customer classification		As per tariff class assignment process for customers with consumption greater than 100 MWh per year.
Long Run Marginal Cost	LRMC	An estimate of the cost (long term variable investment) of augmenting the existing network to provide sufficient capacity for one additional customer to connect to the network or an additional MW of demand.
Low Voltage	LV	Refers to the sub-11 kV network
Maximum demand		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.
National Metering Identifier	NMI	A unique number assigned to each metering installation.
Network capacity		The maximum demand (kW) that the distribution network can provide for at any one time.
Network Coupling Point	NCP	The point at which connection assets join a distribution network, used to identify the distribution service price payable by a customer.
Network Tariff Code	NTC	Ergon Energy's nominated code that represents the network tariff being charged to customers for network services.
Network Use of System	NUOS	The tariff for use of the distribution and transmission networks. It is the sum of both Distribution Use of System (DUOS) and DPPC.
Non-demand tariff		The tariff is based around a fixed daily component and the actual usage (or energy), expressed in kWh, used by the customer.
Power factor		Power factor is the ratio of kW to kVA, and is a useful measure of the efficiency in the use of the network infrastructure. The closer the power factor is to one (1), the more efficiently the network assets are utilised. Power factor = kW / kVA
Public lights - Major		Lamps in common use for major road lighting including: • High Pressure Sodium above 100 watt • Metal Halide above 125 watt • Mercury Vapour above 125 watt, and • Light Emitting Diode 36 watt and above.
Public lights - Minor		All lamps in common use for minor road lighting, including: • High Pressure Sodium – up to and including 100 watt • Metal Halide – up to and including 125 watt • Mercury Vapour – up to and including 125 watt • Light Emitting Diode below 36 watt • Compact Fluorescent, Fluorescent and Incandescent – all wattages, and • Low Pressure Sodium – all wattages.

Term	Acronym	Definition
Queensland Government Solar Bonus Scheme	SBS FiT	A program that pays residential and other small energy customers for the surplus electricity generated from roof-top solar photovoltaic (PV) systems that is exported to the Queensland electricity grid.
Regulatory depreciation		Also referred to as the return of capital – the sum of the (negative) straight–line depreciation and the (positive) annual inflation effect on the opening regulatory asset base (RAB).
Service Target Performance Incentive Scheme	STPIS	A scheme developed and published by the AER in accordance with clause 6.6.2 of the NER, that provides incentives (that may include targets) for DNSPs (including Ergon Energy) to maintain and improve network performance.
Side constraint		A side constraint is an upper limit on price increases applied at the tariff class level for SCS and is calculated in accordance with clause 6.18.6 of the NER and the AER Determination Decision. The purpose of a side constraint is to mitigate the impact of prices on customers from one year to the next within a regulatory control period.
Site-specific charge		This charge is calculated for a site and is specific to the individual connection point.
Small customer classification		As per tariff class assignment process for customers with consumption less than 100 MWh per year.
Smart meter		Digital, interval and advanced Type 1-4 meters. Meters capable of measuring electricity usage in specific time intervals and enabling tariffs that can vary by time of day.
Solar Photovoltaic	Solar PV	A system that uses sunlight to generate electricity for residential use. The system provides power for the premises with any excess production feeding into the electricity grid.
Standard Control Service	SCS	Distribution services that are central to electricity supply and therefore relied on by most (if not all) customers. This service classification includes network services (e.g. construction, maintenance and repair of the network), basic connection services and Type 7 metering services (i.e. unmetered connections such as traffic lights).
Tariff		The set of charges applied to a customer in the respective billing period. A tariff consists of one or more charging parameters that comprise the total tariff rate.
Threshold demand		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 Seasonal Time of Use Demand 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.
Time-of-use	ToU	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, shoulder and off-peak periods.
Total annual revenue	TAR	Refer to AER, Final Decision Ergon Energy determination 2020 to 2025, Attachment 13 – Control Mechanism, June 2020.
Transmission Use of System charge	TUOS	Superseded terminology for DPPC which are charges incurred for use of the transmission network.
Unmetered supply		A customer who takes supply where no meter is installed at the connection point.

Term	Acronym	Definition
Usage or Volume charge		A type of charge (charging parameter) included in 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). This part of the tariff seeks to reflect costs not directly allocated to network drivers and costs that are proportional to the size of the customer.
X Factor		Under the CPI – X form, prices or allowed revenues are adjusted annually for inflation (CPI) less an adjustment factor ‘X’. The X Factor represents the change in real prices or revenues each year, so the DNSP can recover the costs that it expects to incur over the regulatory control period.

Attachment 1 – 2023-24 Network Price List

Refer to attached network prices list for 2023-24.

Attachment 2 – 2024-25 Indicative Pricing Schedule

Refer to attached Indicative pricing schedule for 2024-25.

Attachment 3 – 2023-24 annual SCS pricing model

Refer to attached compliance model.

Attachment 4 – 2023-24 annual ACS pricing model

Refer to attached compliance model.