Queensland Competition Authority

Draft determination

Regulated retail electricity prices for 2019–20

February 2019

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SUBMISSIONS

Closing date for submissions: 12 April 2019

Public involvement is an important element of the decision-making processes of the Queensland Competition Authority (QCA). Therefore submissions are invited from interested parties concerning its assessment of regulated retail electricity prices for 2019–20. The QCA will take account of all submissions received within the stated timeframes.

Submissions, comments or inquiries regarding this paper should be directed to:

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Confidentiality

In the interests of transparency and to promote informed discussion and consultation, the QCA intends to make all submissions publicly available. However, if a person making a submission believes that information in the submission is confidential, that person should claim confidentiality in respect of the document (or the relevant part of the document) at the time the submission is given to the QCA and state the basis for the confidentiality claim.

The assessment of confidentiality claims will be made by the QCA in accordance with the *Queensland Competition Authority Act 1997*, including an assessment of whether disclosure of the information would damage the person's commercial activities and considerations of the public interest.

Claims for confidentiality should be clearly noted on the front page of the submission. The relevant sections of the submission should also be marked as confidential, so that the remainder of the document can be made publicly available. It would also be appreciated if two versions of the submission (i.e. a complete version and another excising confidential information) could be provided.

A confidentiality claim template is available on request. We encourage stakeholders to use this template when making confidentiality claims. The confidentiality claim template provides guidance on the type of information that would assist our assessment of claims for confidentiality.

Public access to submissions

Subject to any confidentiality constraints, submissions will be available for public inspection at our Brisbane office, or on our website at www.qca.org.au. If you experience any difficulty gaining access to documents please contact us on (07) 3222 0555.

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EXECUTIVE SUMMARY

The Queensland Competition Authority (QCA) has made its draft determination on the regulated retail electricity prices (notified prices) that will apply in regional Queensland from 1 July 2019 to 30 June 2020. Notified prices are paid by regional Queensland customers who have not entered into a market contract with their retailer. The QCA was delegated the role of setting notified prices for regional Queensland customers in December 2018 ('the delegation') by the Minister for Natural Resources, Mines and Energy (the Minister). The QCA is required to set prices in accordance with that delegation and the *Electricity Act 1994* (Qld) (the Electricity Act).

It is important to note that the QCA's draft determination will not affect customer bills. The prices discussed in our draft determination are indicative only. To illustrate the hypothetical impacts of these draft notified prices, we provide comparisons of the annual amount typical customers would have paid under 2018–19 notified prices, and the annual amount they would potentially pay under the draft 2019–20 notified prices.

The draft determination forecasts a fall in notified prices for typical customers, largely due to a reduction in energy costs.

The QCA appreciates the valuable contributions that stakeholders have made to our price determination process, especially those who made submissions to our interim consultation paper. While we have not referred to all arguments or submissions in our final determination, we have carefully considered the issues raised in each submission.

What is the QCA's proposed approach to setting 2019–20 notified prices?

Our approach to setting 2019–20 notified prices is consistent with the Minister's delegation and with the approach we took in the 2018–19 price determination. Under this approach, we propose to calculate notified prices using a network cost plus energy and retail costs (N+R) approach, and set price levels consistent with the Queensland Government's Uniform Tariff Policy (UTP).[1] That is, residential and small business customer tariffs will be based on the costs of supplying electricity in south east Queensland[2], and large business customer tariffs will be based on the lowest costs of supply in regional Queensland.[3]

The UTP generally results in regional residential, small business and some large business customers paying electricity prices that are lower than the costs of supplying these customers. The shortfall is made up via a subsidy paid by the Queensland Government, which is forecast to be approximately $465 million[4] in 2018–19.

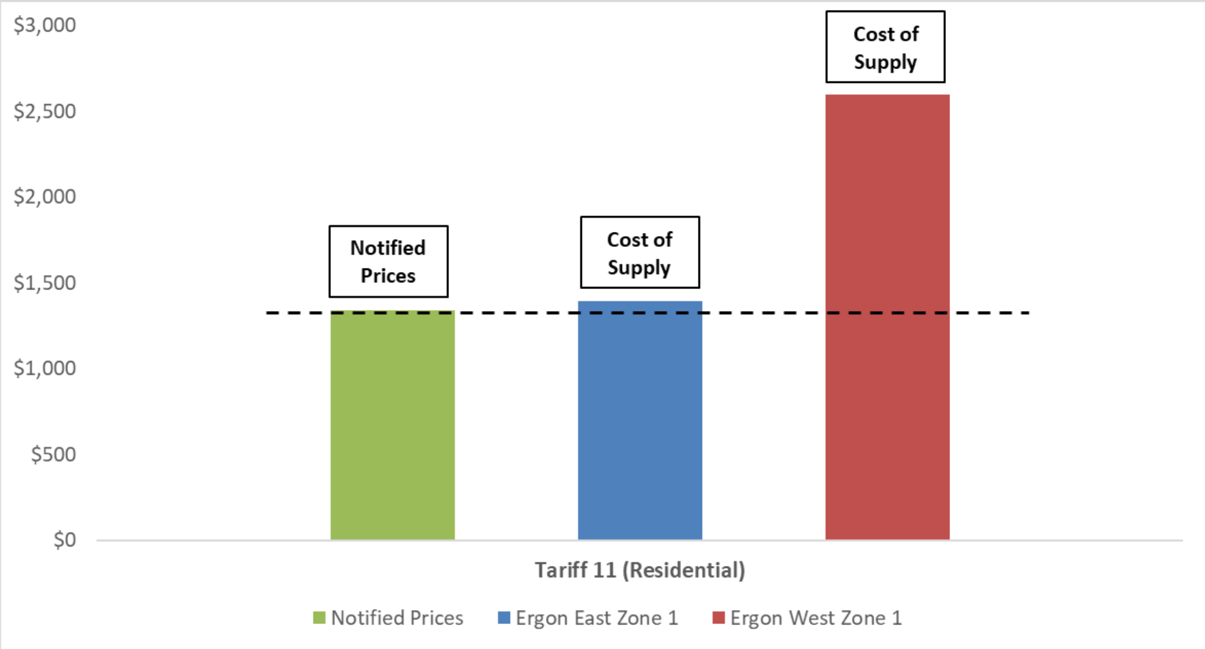
[1] According to the delegation, the government's Uniform Tariff Policy provides that, 'wherever possible, customers of the same class should pay no more for their electricity, regardless of their geographic location.'

[2] The Energex distribution area.

[3] Ergon Distribution’s east pricing zone, transmission region one.

[4] Queensland Government, *Queensland Budget 2018–19—Budget Strategy and Outlook*, Budget Paper no. 2, 2018, https://budget.qld.gov.au/files/BP2-2018-19.pdf, p. 162.

Figure 1 Notified electricity prices for typical residential customers compared to actual costs of supply for regional Queensland, 2019–20 (incl. GST)



Note: The cost of supply excludes any standing offer adjustment. Ergon East Zone 1 refers to Ergon Distribution's east pricing zone, transmission region 1. Ergon West Zone 1 refers to Ergon Distribution's west pricing zone, transmission region 1.

Standing offer adjustment

For residential and small business customers, the N+R methodology produces estimates of efficient south east Queensland price levels for customers on *market contracts*. However, notified price customers in regional Queensland are supplied through standing offer contracts, which contain additional customer benefits, and generally feature higher prices as a result.

Accordingly, the delegation[5] specifies that, in order to reflect the UTP, the QCA should consider adjusting residential and small business prices by 5 per cent to reflect the additional value of standard contracts. The QCA's draft decision is to concur with the Minister that it is appropriate to make an adjustment (referred to as the standing offer adjustment) of 5 percent for 2019–20. This is discussed further in Chapter 6.

Headroom

Providing a headroom allowance is a generally accepted approach aimed at stimulating competition in competitive markets where price regulation still applies, such as that for large business customers in regional Queensland. Given that competition in the large business customer segment in regional Queensland is developing, and has the potential to develop further, we propose to maintain our approach of including a 5 per cent headroom allowance in 2019–20. This is discussed further in Chapter 6.

What impact would the QCA's draft price determination have on customer bills?

As discussed, the QCA's draft determination does not affect electricity bills. However, so that stakeholders can assess the potential impact of our proposed methodology, we show the indicative impact our draft determination would have on customer bills (Figures 2 to 4).

[5] See Appendix A.

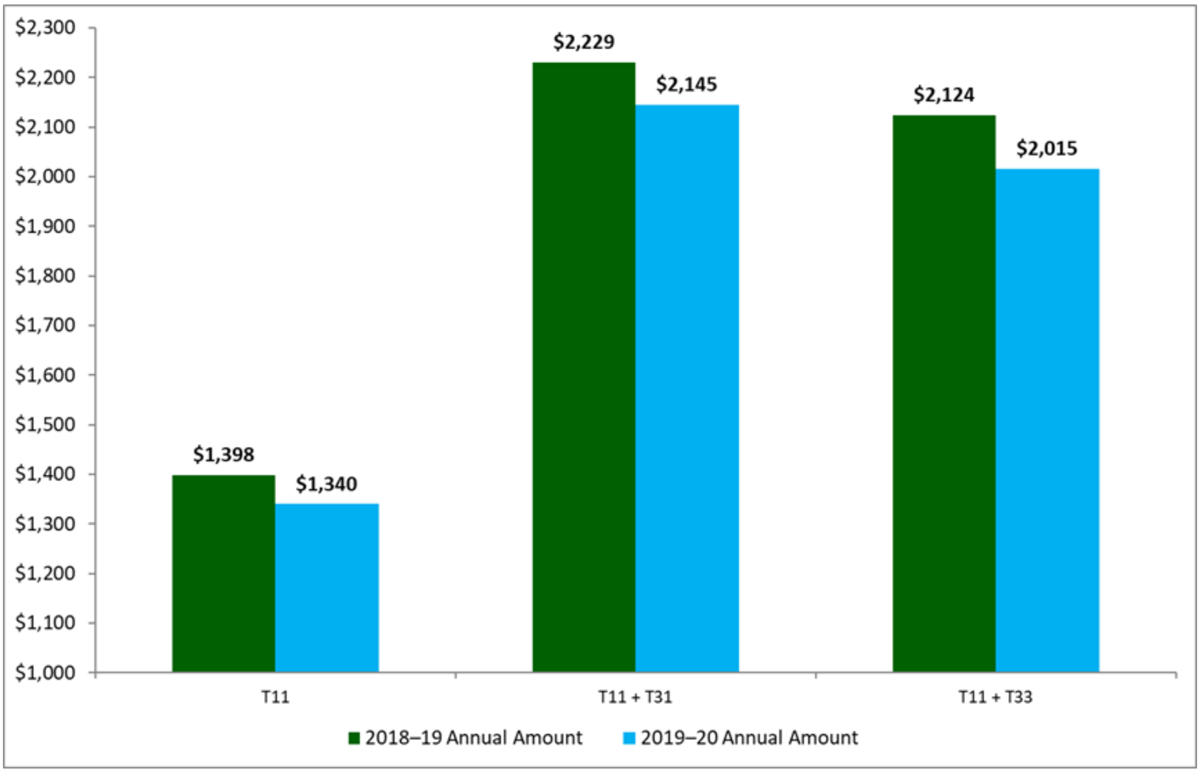
Residential customers

The typical residential customer on the main retail tariff (tariff 11) would pay around $58 (or 4.1 per cent) less per annum for their electricity usage and service fee based on the draft 2019–20 notified prices (Figure 2).[6]

The typical residential customer on a combination of tariff 11 and controlled load[7] tariff 31 would pay around $84 (or 3.8 per cent) less per annum, while the typical customer on a combination of tariff 11 and tariff 33 would pay around $109 (or 5.1 per cent) less per annum.

It is important to remember that the impact will be different for customers with different levels of electricity consumption.

Figure 2 Potential impact of draft determination notified prices on typical residential customers (incl. GST), 2019–20



Note: Annual amounts are rounded to the closest dollar, and exclude metering charges.

Small business customers

The typical small business customer on flat-rate tariff 20 would pay around $180 (or 7.2 per cent) less per annum for their electricity usage and service fee, based on the draft 2019–20 notified prices.[8]

[6] Customers will incur metering charges in addition to notified prices. As metering charges vary from customer to customer according to a range of factors, and are excluded from 2019–20 notified prices, they have not been included in the customer impact analysis.

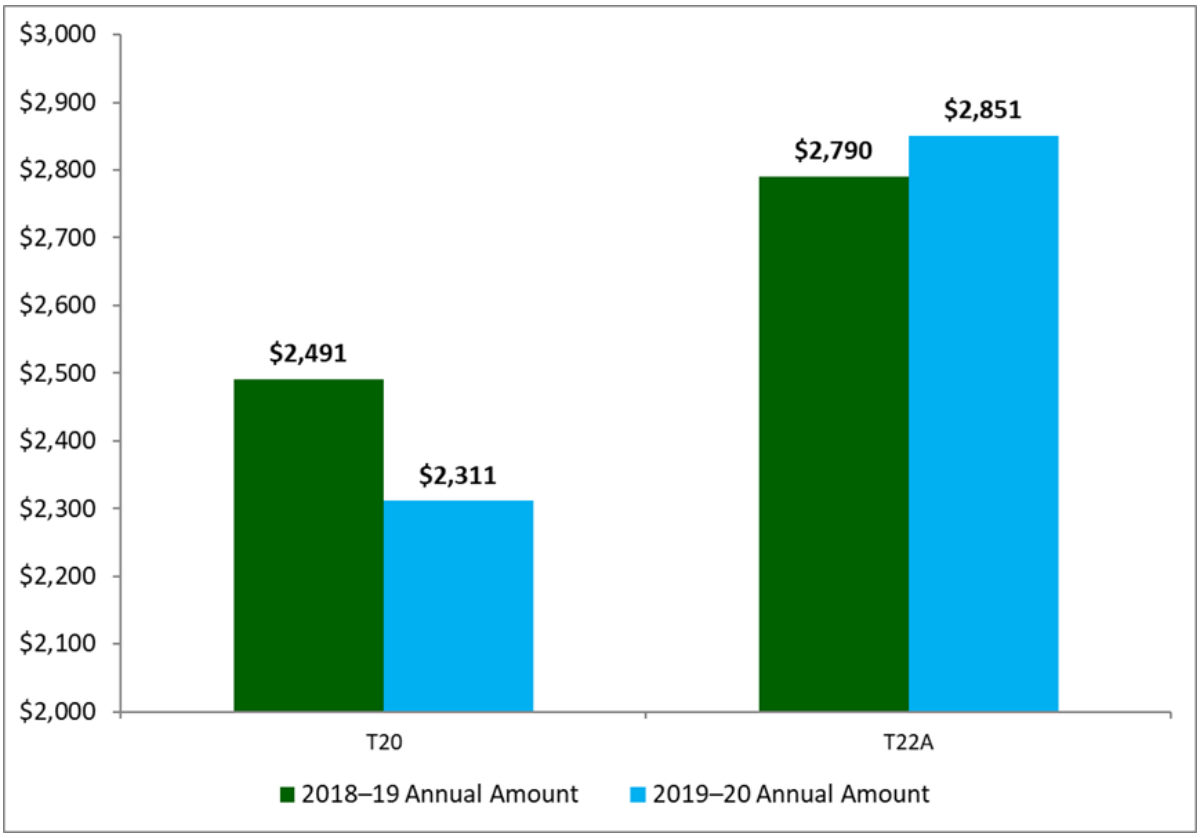
[7] Controlled load tariffs may be used for appliances such as water heaters and pool pumps. These tariffs are cheaper than tariff 11, as customers are only guaranteed supply for a set number of hours (tariff 31 guarantees supply for eight hours per day and tariff 33 guarantees supply for 18 hours per day).

[8] Customers will incur metering charges in addition to notified prices. As metering charges vary from customer to customer according to a range of factors, and are excluded from 2019–20 notified prices, they have not been included in the customer impact analysis.

The typical small business customer on time-of-use tariff 22A would pay $61 (or 2.2 per cent) more per annum for their electricity usage and service fee in 2019–20.[9]

It is important to remember that the impact will be different for customers with different levels, and patterns, of electricity consumption.

Figure 3 Potential impact of draft determination notified prices on typical small business customers (incl. GST), 2019–20



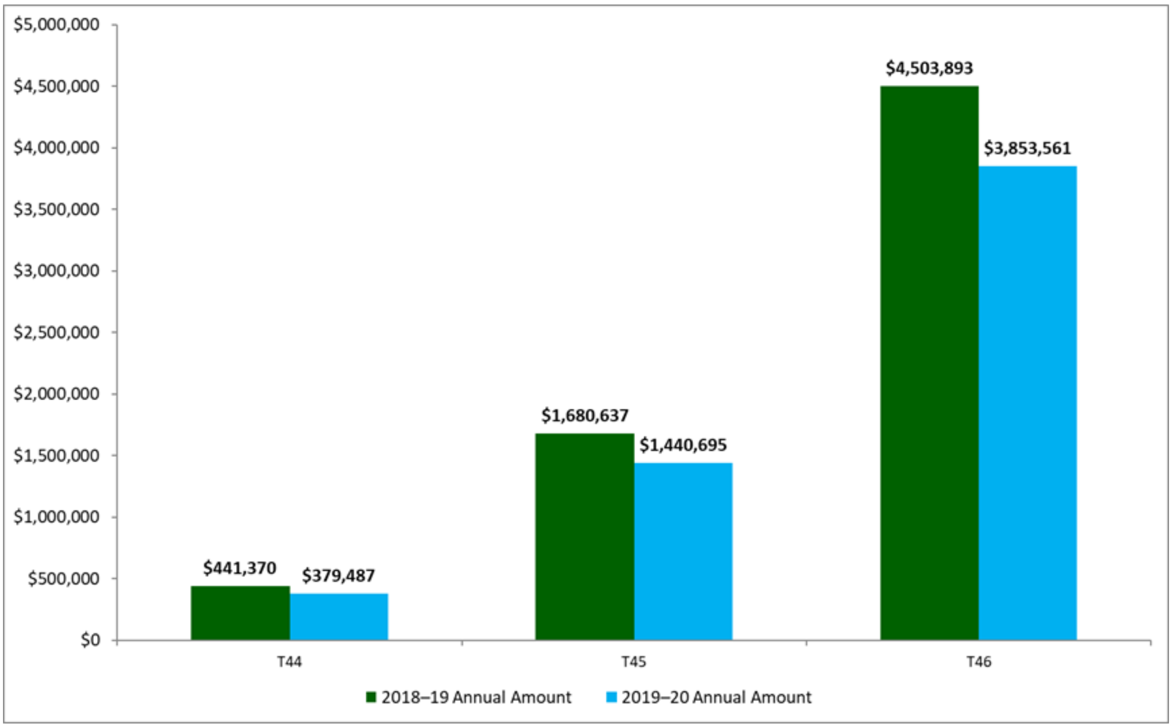
Note: Annual amounts are rounded to the closest dollar, and exclude metering charges.

Large business customers

A typical large business customer on tariff 44, 45 or 46 would pay between 14.0 per cent and 14.4 per cent less per annum for their electricity usage and service fee in 2019–20. However, it is important to note that bill impacts for individual customers will vary depending on their level and pattern of consumption.

[9] This increase is primarily driven by higher network charges for the peak period.

Figure 4 Potential impact of draft determination notified prices on typical large business customers (incl. GST), 2019–20



Note: Annual amounts are rounded to the closest dollar, and exclude metering charges.

Obsolete tariffs

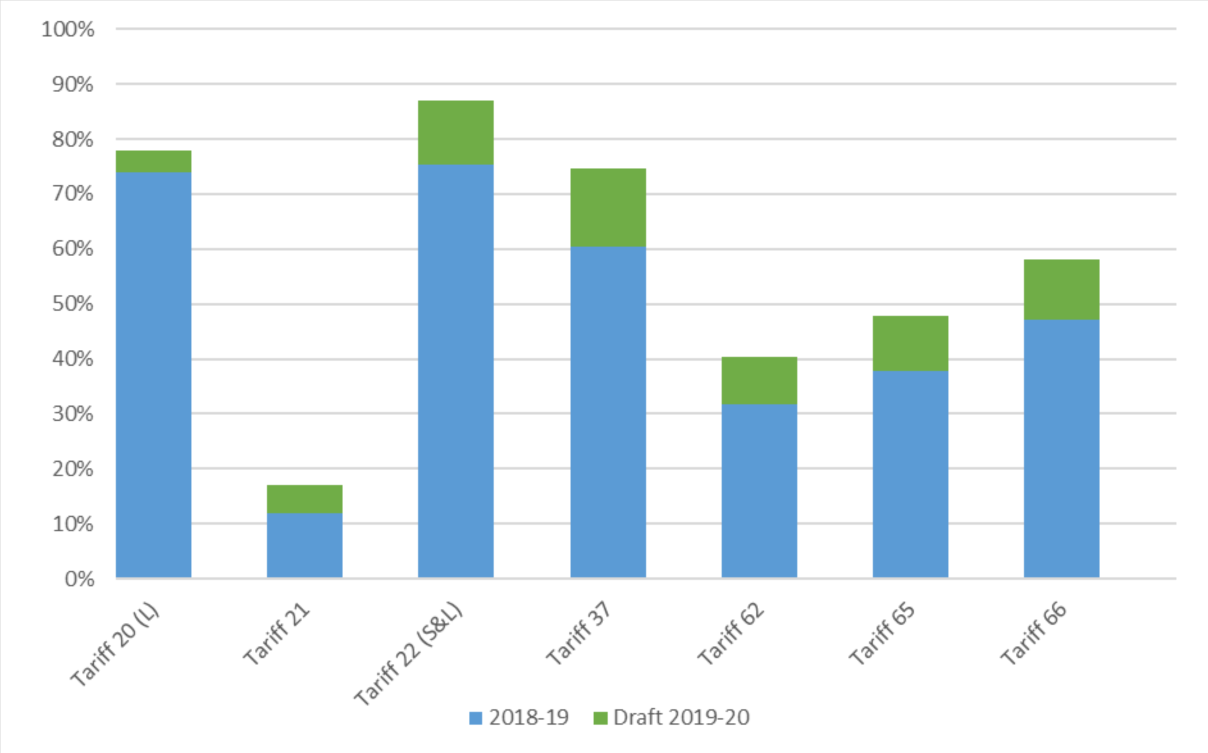
Around 35,000 connections, including some used by farmers and irrigators, are supplied under legacy retail tariffs. These tariffs were made available for several years to allow customers to transition their businesses to standard business tariffs. With the exception of tariffs 47 and 48[10], all of these tariffs will expire on 30 June 2020. In accordance with the delegation, the QCA's draft determination is to allow existing customers to remain on these tariffs until they expire, but close these tariffs to new customers. This is to ensure that businesses are not making investment decisions based on tariffs which will shortly expire.

A significant number of customers on these expiring tariffs would be better off on the standard business tariffs other regional businesses must pay. According to data from Ergon Retail, over 30 per cent of connections on expiring tariffs would have saved money on standard business tariffs. Based on the 2019–20 draft prices, around 40 per cent of all connections on expiring tariffs would save money on standard business tariffs in 2019–20. Figure 5 shows these figures for each obsolete tariff.

In addition, it is possible that even more small business customers could save on time-of use-tariffs.

[10] Tariffs 47 and 48 are due to expire on 30 June 2022.

Figure 5 Approximate proportion of connections for each expiring obsolete tariff that could transition to standard business tariffs without any negative impact

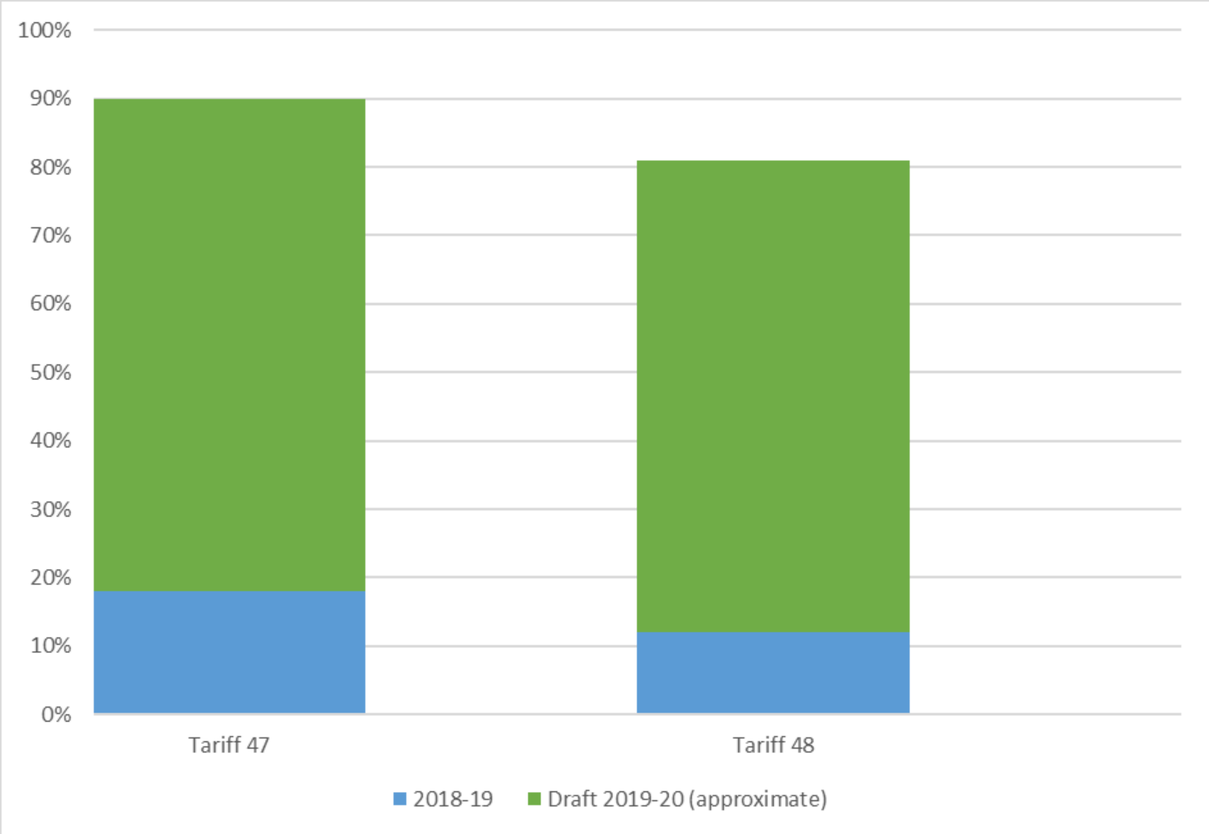


Given these tariffs will shortly expire, and significant potential exists for customers to pay less for electricity on standard business tariffs, we strongly encourage customers on expiring tariffs to contact their retailer for advice on the most appropriate tariffs for their business.

Tariffs 47 and 48

Around 60 large business connections are supplied through tariffs 47 or 48. While these tariffs will remain available until 30 June 2022, a significant number of customers could be better off on standard business tariffs (Figure 6). We encourage customers on these tariffs to contact their retailer to see if they could benefit from moving to standard business tariffs before tariffs 47 and 48 expire.

Figure 6 Proportion of connections on tariffs 47 and 48 that could transition to standard business tariffs without any negative impact



THE ROLE OF THE QCA—TASK, TIMING AND CONTACTS

The Queensland Competition Authority (QCA) is an independent statutory body which promotes competition as the basis for enhancing efficiency and growth in the Queensland economy.

The QCA's primary role with respect to electricity pricing is to set regulated retail electricity prices in accordance with the requirements of the delegation from the Minister for Natural Resources, Mines and Energy (Appendix A) and the *Electricity Act 1994* (the Electricity Act).

Key dates

Review of regulated electricity prices for 2019–20: timetable

Release of the draft determination	28 February 2019
Workshops on draft determination	Between 18 March and 1 April 2019
Submissions due on draft determination	12 April 2019
Release of the final determination	By 31 May 2019

Registration of interest

http://www.qca.org.au/contact-us

Contacts

Enquiries regarding this project should be directed to:

ATTN: Leigh Spencer or Adam Liddy
Tel (07) 3222 0555
www.qca.org.au/Contact-us

1 INTRODUCTION

The Queensland Competition Authority (QCA) has received a delegation from the Minister for Natural Resources, Mines and Energy (the Minister) to determine regulated retail electricity prices (notified prices). The delegation specifies that the notified prices will apply to standard contract customers for customer retail services in Queensland, other than those in the Energex distribution area, for the tariff year 1 July 2019 to 30 June 2020.[11]

1.1 The review process

Interim consultation paper

On 21 December 2018, we released an interim consultation paper (ICP), advising interested parties of the commencement of our review. We received 13 submissions in response (see Appendix B). The ICP and all non-confidential submissions are available on the QCA's website.[12]

Draft determination

This draft determination contains our draft regulated retail tariffs and prices for 2019–20 (see Chapter 8). In making this draft determination, we have taken into account the requirements of the Electricity Act and the 2019–20 delegation; matters raised in stakeholder submissions; ACIL Allen's draft report on the estimated energy costs[13]; and our own analysis.

As part of our consultation program following release of the draft determination, we are planning to hold workshops in March 2019 in Ayr, Bundaberg, Cairns, Charleville, Gladstone, Mackay, Rockhampton, Toowoomba, Townsville, Brisbane, and other locations, depending on the level of stakeholder interest. Stakeholders can register their interest for a workshop on our website.[14]

Submissions in response to this draft determination are due by 12 April 2019. Details on how to make a submission are at the front of this paper.

We appreciate the contribution of stakeholders who make submissions on our review. While we may not necessarily reference all arguments or submissions in our determinations, we carefully consider each submission. Issues that have been raised but are outside the scope of our review are discussed in Appendix C. All documents relating to this review are available on our website.[15]

Final determination

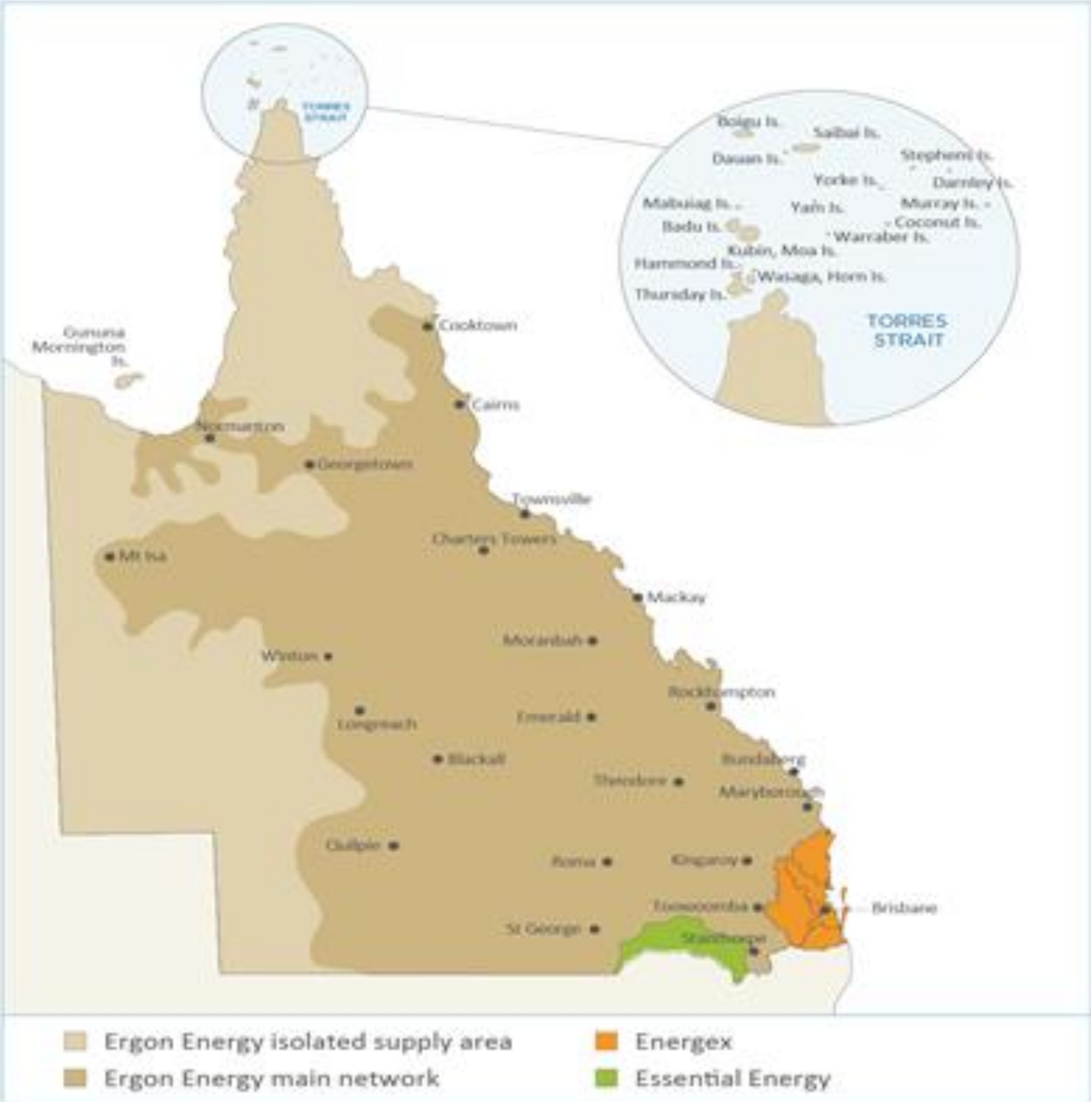
We are required to publish a report on our final determination and gazette notified prices no later than 31 May 2019.

[11] See Appendix A for a copy of the delegation.
[12] http://www.qca.org.au/Electricity/Regional-consumers/Reg-Electricity-Prices/In-Progress/2019-20-Regulated-electricity-prices-for-regional.
[13] ACIL Allen, February 2019.
[14] http://www.qca.org.au/workshops.
[15] http://www.qca.org.au/Electricity/Regional-consumers/Reg-Electricity-Prices/In-Progress/2019-20-Regulated-electricity-prices-for-regional.

1.2 Access to notified prices

Notified prices are only available to residential, small business and standard contract large business customers outside of the Energex distribution area. Notified prices are not available to customers located in the Energex distribution area.[16]

Figure 7 Access to notified prices



1.3 Legislative framework—the Electricity Act

We determine notified prices in accordance with our obligations under the Electricity Act. While that Act does not specify criteria or principles to be applied in making a price determination, it directs us to have regard to the following matters:

(a) the actual costs of making, producing or supplying the goods or services

[16] In accordance with last year's delegation, the 2018–19 final determination clarified that notified prices would apply for Queensland customers in Essential Energy's distribution area in southern Queensland. These arrangements will also apply for the 2019–20 determination. Notified prices no longer apply to customers in south east Queensland, where retail price regulation was removed on 1 July 2016.

(b) the effect of the price determination on competition in the Queensland retail electricity market

(c) any matter we are required by delegation to consider.[17]

In addition, the Electricity Act also provides that we may have regard to any other matter we consider relevant.

One matter we consider to be relevant, and intend to have regard to, is the objects of the Electricity Act. These objects are to:

(a) set a framework for all electricity industry participants that promotes efficient, economical and environmentally sound supply and use

(b) regulate the electricity industry and electricity use

(c) establish a competitive electricity market in line with the national electricity industry reform process

(d) ensure that the interests of customers are protected

(e) take into account national competition policy requirements.[18]

1.4 Matters we are required to consider by the Minister's delegation

The delegation requires us to consider the matters outlined below when determining notified prices for 2019–20. The delegation also requires us to consider that notified prices do not apply to customers in the Energex distribution area, as discussed above.

The Uniform Tariff Policy

Consistent with previous price determinations, we are required to consider the Queensland Government's Uniform Tariff Policy (UTP). The UTP provides that:

> wherever possible, customers of the same class should pay no more for their electricity, regardless of their geographic location.[19]

The covering letter to the delegation also specifies that, for the purpose of setting notified prices, the Queensland Government's UTP is an important consideration.[20]

The UTP provides that, wherever possible, customers of the same class should pay no more for their electricity, regardless of their geographic location. However, the government considers that, in order to reflect the intent of the UTP, for small customers the QCA should give consideration to including an adjustment in notified prices that appropriately reflects the additional value of the terms and conditions of standard retail contracts compared to market contracts.

The government also considers that notified prices for large business customers in regional Queensland should be based on the costs of supply in the Ergon Distribution east zone, transmission region one, rather than on the actual costs of supply. This area is one of the lowest cost areas of the network, and also has the highest number of large and very large customers.

[17] Section 90(5)(a) of the Electricity Act.
[18] Section 3 of the Electricity Act.
[19] Clause 5(b) of the delegation (Appendix A).
[20] A copy of the Minister's covering letter is provided in Appendix A.

As the actual costs of supplying residential, small business and some large business customers in regional Queensland are generally higher than notified prices[21], the application of the UTP will benefit these customers.

The difference between the costs of supply in south east Queensland and regional Queensland is largely due to the higher network costs associated with supplying electricity over long distances to a low-density customer base. These additional costs are significant, with the Queensland Government expecting to pay a subsidy of approximately $465 million in 2018–19 to give effect to the UTP.

'N+R' cost build-up methodology

Consistent with the approach in previous price determinations, we must consider using the network (N) plus retail (R) cost build-up methodology when determining notified prices for 2019–20. Under this methodology, the N costs (network costs) are generally treated as a pass-through and the R costs (energy and retail costs) are determined by the QCA.

The network cost (N) component

When calculating the N component for each regulated retail tariff, the delegation requires that the QCA consider continuing the general approach it has applied in previous price determinations. This means using the Energex network charges and tariff structures when we determine non-time-of-use retail tariffs[22] for residential and small business customers (tariffs 11, 20, 31, 33, 41 and 91[23]).

When we determine time-of-use[24] and time-of-use demand retail tariffs[25] for residential and small business customers (tariffs 12A, 14, 22A and 24), we must consider basing the N component on the price level of network charges to be levied by Energex and the network tariff structures of Ergon Distribution.

For large business customers, we must consider basing the N component on the Ergon Distribution network charges and tariff structures. We adopted this approach in previous price determinations.

Transitional arrangements

We are required to consider reclassifying transitional tariffs as obsolete tariffs (for example, tariffs 20 (large), 21, 22 (small and large), 37, 62, 65 and 66).

Adjustments to the charges for standard contract customers

We are required to consider continuing to allow two adjustments to the charges for standard contract customers:

[21] The differences in the costs of supply are largely due to the higher network costs associated with supplying electricity over long distances to a low-density customer base.

[22] Non-time-of-use tariffs are retail tariffs with usage charge rates that do not vary with the time and/or level of consumption.

[23] Tariff 91 applies to unmetered supplies (except street lighting).

[24] Time-of-use tariffs are retail tariffs with usage charge rates that vary with the time of consumption.

[25] Time-of-use demand tariffs are retail tariffs with usage and demand charge rates that vary with the time of consumption and/or demand.

(a) allowing retailers to charge standard contract customers for amounts that are not included in the regulated retail tariff, in accordance with a program or scheme for the purchase of electricity from renewable or environmentally friendly sources

(b) allowing Ergon Energy Queensland Pty Ltd to issue annual rewards to customers that opt in to its EasyPay Reward scheme, having met the eligibility requirements of the scheme.

The details of these government policies are outlined in the delegation and discussed in Chapter 6.[26]

1.5 Electricity prices

Several factors combine to make up the annual notified price electricity bill, all of which vary from year to year. These factors include the costs of:

(1) transmission and distribution networks which transport electricity

(2) purchasing electricity from the wholesale market

(3) operating a retail business, such as call centres and billing systems

(4) government initiatives, such as the Renewable Energy Target (RET)

(5) other factors, such as the standing offer adjustment.

Electricity bill trends

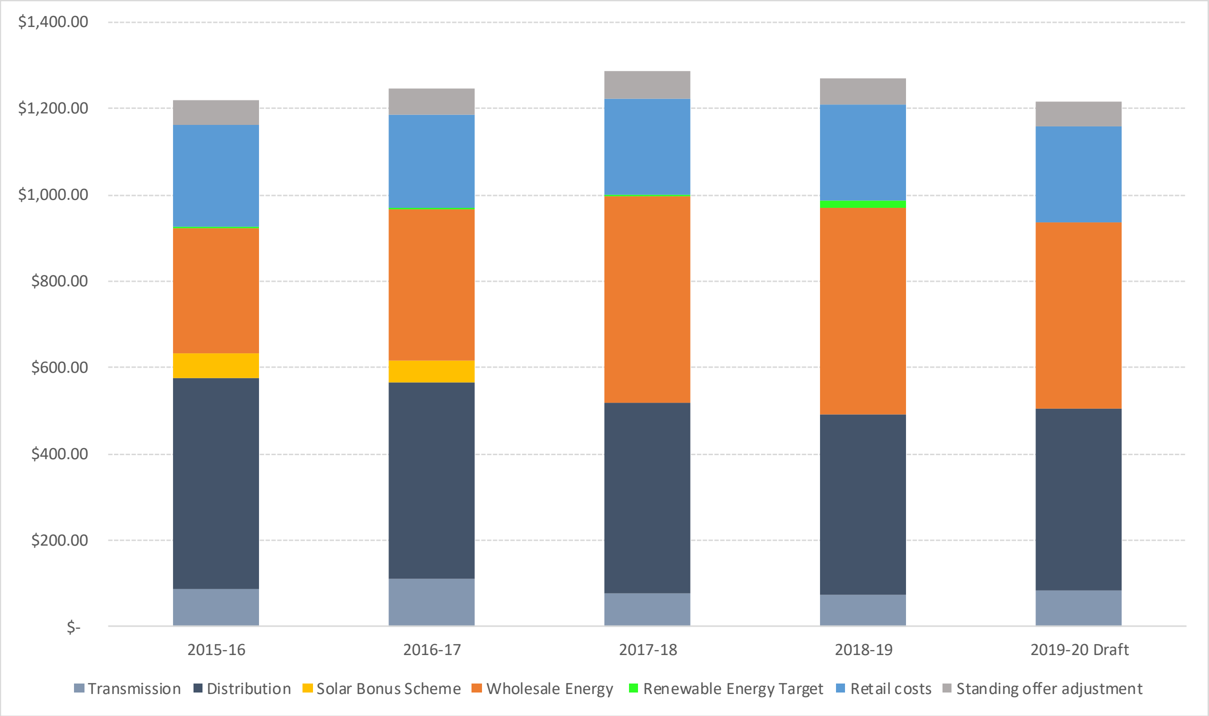
We have compiled data on the annual bill of a typical customer using notified prices from 2015–16 to 2019–20 (draft determination notified prices for 2019–20).

Of all components, items (1) and (2) in the list above generally contribute the most to a customer's annual bill (on average).

The data shows the annual electricity bill for typical residential and small business customers gradually increased from 2015–16 to 2017–18, then decreased from 2017–18 to 2018–19.

[26] The 2019–20 delegation is included at Appendix A.

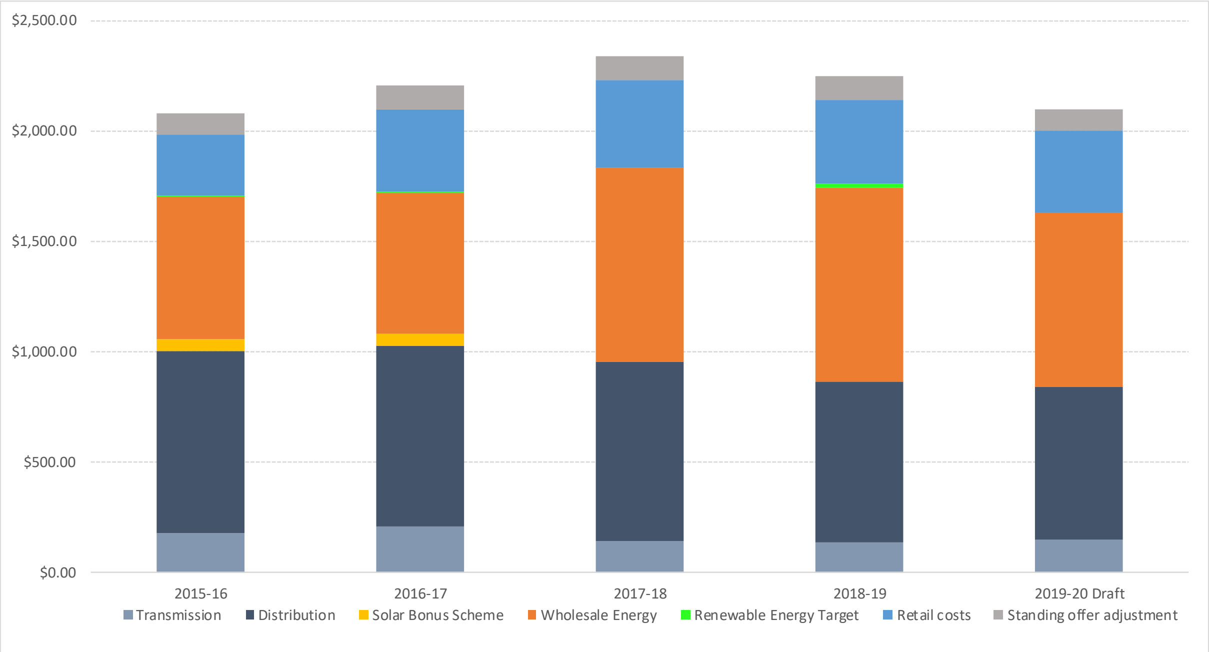
Figure 8 Typical residential customer—annual bill breakdown, 2015–2020



Note: Wholesale energy costs in this chart include wholesale costs when purchasing electricity from the NEM, NEM management fees, ancillary services charges, prudential capital costs and energy losses.

Source: QCA analysis.

Figure 9 Typical small business customer—annual bill breakdown, 2015–2020



Note: Wholesale energy costs in this chart include wholesale costs when purchasing electricity from the NEM, NEM management fees, ancillary services charges, prudential capital costs and energy losses.

Source: QCA analysis

An analysis of the trends for each cost component of the bill from 2015–16 to 2018–19 is discussed below. Changes in each cost component as a result of this 2019–20 draft determination are discussed in relevant chapters of this report.

Network costs

Network costs consist of transmission and distribution costs. The data shows that, between 2015–16 and 2018–19, transmission costs remained relatively stable, while distribution costs have slightly decreased.

As network costs are regulated by the Australian Energy Regulator (AER), the decrease in distribution costs between 2014–15 and 2018–19 is attributable to the decrease in AER-approved network costs over this period, for both a typical residential and small business customer. Network costs are discussed in Chapter 3.

Wholesale energy costs

A retailer incurs wholesale energy costs when purchasing electricity from the National Electricity Market (NEM) to meet the electricity demand of its customers. Between 2015–16 and 2018–19, wholesale energy costs increased for residential and small business customers.

Wholesale energy costs have increased due to a broad range of factors, including a tightening of the supply and demand balance in the NEM. For instance, the significant increase in energy costs between 2016–17 and 2017–18 was due to an increase in demand for electricity from the LNG industry in Queensland, an increase in gas prices for gas-fired generation and the closure of the Hazelwood power station in Victoria in 2017. However, in 2019–20, wholesale energy costs are expected to decrease for customers settled on the net system load profile, with decreases primarily driven by a projected decrease in spot price volatility. Wholesale energy costs are discussed in Chapter 4.

Renewable Energy Target (RET) and Solar Bonus Scheme costs

The costs associated with the RET have remained relatively stable for both a typical residential and small business customer from 2015–16 to 2018–19, although there was an increase in 2018–19 due to an adjustment by the Clean Energy Regulator associated with the Small Scale Renewable Energy Scheme costs. The RET is discussed in Chapter 4.

The costs associated with the Solar Bonus Scheme have been fully funded from the Queensland Government budget from 2017–18 onwards. Since then, these costs no longer form a component of customer bills. The Solar Bonus Scheme is now a legacy scheme and cannot be accessed by new customers.

Retail costs and standing offer adjustment

Between 2015–16 and 2018–19, retail costs have been relatively stable. Additionally, the standing offer adjustment has remained at a constant rate of 5 per cent.

Retail costs are discussed in Chapter 5, and the standing offer adjustment is discussed in Chapter 6.

2 PRICING FRAMEWORK

The objects of the Electricity Act and the matters we are required to consider under the Electricity Act indicate that cost-reflective prices and the promotion of retail competition are important guiding principles in making a price determination. Cost-reflectivity is important for efficiency and equity reasons. The 2018–19 price determination was designed to support retail competition in the large business customer segment in regional Queensland.

Under the Minister's delegation, we are required to consider the UTP. The application of the UTP in previous price determinations has resulted in most notified prices being based on costs of supply which are below the actual costs of supply.

Given there is a degree of conflict between the matters we are required to consider under the Electricity Act and those we are required to consider under the Minister's delegation, we have considered a broad range of possible pricing approaches for 2019–20, particularly for the residential and small business customers (small customers) in Ergon Distribution's distribution area.

Our draft decision is to base notified prices for small customers in regional Queensland on the expected costs of supply in south east Queensland, plus a standing offer adjustment, and to continue to base notified prices for large business customers in regional Queensland on the lowest costs of supply in regional Queensland, which is Ergon Distribution's east pricing zone, transmission region one.

2.1 Residential and small business customers

In order to take into account the requirements of the Electricity Act and the UTP, we have considered a range of pricing approaches to setting the pricing framework for determining notified prices for small customers.

Cost build-up approach

The Minister's delegation requires us to consider an N+R cost build-up methodology when determining notified prices for 2019–20. Under this methodology, the N costs (network costs) are generally treated as a pass-through and the R costs (energy and retail costs) are determined by the QCA.

QCA position

Our draft decision is to continue estimating the costs of supply for each retail tariff using an N+R cost build-up approach, where we treat the N (network cost) component as a pass-through, and determine the R (energy and retail cost) component. This is consistent with the Minister's delegation and previous determinations.

Cost base

We also need to consider the appropriate costs of supply on which to base the notified prices for small customers. Three approaches have been considered.

We could maintain the approach we took in the 2018–19 price determination and base the notified prices on the costs of supply in south east Queensland (that is, costs in Energex's distribution area). As the costs of supply in south east Queensland are generally lower than those in regional Queensland, adopting this approach would result in customers continuing to pay prices that do not reflect their actual costs of supply. This would require the ongoing subsidisation of electricity prices by taxpayers, and may potentially encourage inefficient consumption and investment by electricity consumers. For example, a business that decided to invest in electricity-intensive equipment, given subsidised prices, may not have proceeded with the same investment decision if electricity prices reflected their actual cost of supply. However, this approach may be considered appropriate, as it would be consistent with the Queensland Government's definition of the UTP for 2019–20.

Another approach would be to base the notified prices for small customers on the lowest costs of supply in regional Queensland (that is, the costs in Ergon Distribution's east pricing zone, transmission region one). We have used this approach in setting notified prices for large business customers in regional Queensland since 2012. Adopting this approach for small customers would improve the cost reflectivity of the notified prices, relative to setting prices based on the costs of supply in south east Queensland. It would also reduce the amount that taxpayers would pay to subsidise electricity prices in regional Queensland. However, it would be inconsistent with the Queensland Government's definition of the UTP for 2019–20, and may result in substantial price increases for customers. For example, based on estimates for 2018–19, the costs of supplying residential customers in Ergon Distribution's east pricing zone, transmission region one are around 8 per cent higher than the costs of supplying customers of the same class in south east Queensland.

A third approach would be to set the notified prices in each of the pricing regions in Ergon Distribution's distribution area at cost-reflective levels. This approach would promote retail competition and remove the need to subsidise regional electricity prices. However, it would be inconsistent with the UTP, as some small standard retail contract customers would pay more for their electricity, based on their geographic location, than small standard retail contract customers of the same class in other areas of Queensland. Cost-reflective prices would also result in substantial price increases, particularly for customers in western Queensland and those supplied by isolated systems. For example, based on estimates for 2018–19, the costs of supplying residential customers in Ergon Distribution's west pricing zone, transmission region one are around 100 per cent higher than the costs of supplying customers of the same class in south east Queensland.

Energy Queensland, the Queensland Council of Social Service (QCOSS), Kalamia Cane Growers Organisation (Kalamia) and the Queensland Consumers' Association supported the approach of basing the notified prices on the costs of supply in south east Queensland.

Canegrowers Isis also supported the approach of basing notified prices on the costs of supply in south east Queensland, stating that 'alignment to the UTP and the very spirit of the policy maintains equality in supply costs and allows regional commercial customers to remain competitive in a nation where location can so easily prejudice opportunity'.[27]

Origin Energy stated it considered the QCA should continue to base notified prices for residential and small business customers on the costs of supply in south east Queensland to ensure there is continuity and consistency in the application of notified prices.[28]

QCA position

Our draft decision is to continue basing notified prices for residential and small business customers on the costs of supply in south east Queensland. We consider this decision is

[27] Canegrowers Isis, sub. 3, p. 1.
[28] Origin Energy, sub. 8, p. 1.

appropriate because it is consistent with the Queensland Government's UTP, and it avoids the potentially large price increases associated with the other approaches.

Benchmark price level

To establish an appropriate benchmark price level for setting notified prices based on the costs of supply in south east Queensland, we have considered the Queensland Government's definition of the UTP, which provides that, wherever possible, customers of the same class should pay no more for their electricity, regardless of their geographic location. We have also considered the government's view that the more favourable terms and conditions of standard retail contracts (compared to market contracts) should be represented by an adjustment to notified prices of a similar magnitude as made by the QCA in previous determinations.

Customers on standing offers are supplied on the standard retail contract under the National Energy Customer Framework (NECF). This contract contains standard terms and conditions. Customers who do not, or cannot, opt for a market contract are supplied by a standing offer by default.

A retailer can also offer market contracts that have different terms and conditions to standard retail contracts (for example, discounts on the bill if the customer pays early or pays by direct debit). While prices under market contracts are generally lower than standing offer prices, their terms and conditions often mean they offer fewer protections to customers.

In response to the ICP, the Queensland Consumers' Association and Origin Energy provided contrasting comments on this issue.

Origin Energy[29] agreed with the QCA's historical approach to adjust the estimated efficient cost of supply in south east Queensland to account for the expected price differential between lowest prices and standing offers.

The Queensland Consumers' Association was of the view that standing offer prices do not provide an accurate reflection of the costs of supply:

> [S]ince standing offer prices are used by many retailers as the base from which discounts are offered to market contracts, there is an incentive for retailers to set the highest possible standing offer prices in order to be able to advertise high % [sic] discounts and other incentives.
>
> We also have concerns about the validity of the delegation's assumption that a standing offer contract provides significant additional protections, and therefore value, for consumers compared to market offers.[30]

QCOSS supported the comments made by the Queensland Consumers' Association, and said:

> As consistently stated in our previous submissions to the QCA's regional pricing determinations we do not support the inclusion of the standard offer differential to set notified prices in regional Queensland. There is considerable evidence emerging from other National Energy Market (NEM) jurisdictions, such as Victoria, that standing offer prices no longer reflect efficient costs of supply …
>
> While the price gap between standing offers and market offers is increasing, the advantageous conditions gap is decreasing … As such, it is questionable what is the value of terms and conditions of standing offers? We therefore support the comments by the Queensland Consumers Association in its submission to the 2018–19 Interim Consultation Paper that any

[29] Origin Energy, sub. 8, p. 3.
[30] Queensland Consumers' Association, sub. 11, p. 2.

> differential applied by the QCA should not be greater than the 5% applied for 2018–19 and in fact should be considerably lower.[31]

QCA position

The QCA agrees with stakeholders' views that the standing offer price does not necessarily provide an accurate reflection of the costs of supply. However, the QCA regards the more favourable non-price terms and conditions associated with standard retail contracts (such as restricted fee types) compared to market offers as something that provides some value to customers. As a result, our draft decision is to determine notified prices for small customers in regional Queensland based on the expected costs of supply in south east Queensland, plus a standing offer adjustment. We consider the standing offer adjustment in detail in Chapter 6.

2.2 Large business customers

As noted above, in previous price determinations we have based notified prices for large business customers on the costs of supply in the lowest-cost area of regional Queensland (Ergon Distribution's east pricing zone, transmission region one). This approach has encouraged competition in the large business customer market in the east pricing zone, transmission region one. It is also consistent with the Queensland Government's definition of the UTP for 2019–20. However, this approach would not reflect the actual costs of supply in all regions, and would still require the Queensland Government to subsidise electricity prices.

Another approach would be to set fully cost-reflective notified prices. This would encourage competition in regional Queensland outside of the east pricing zone, transmission region one, and promote long-term efficient use of electricity services in regional Queensland in the large business customer market. However, it would introduce significant price increases for customers, especially customers in western Queensland and those supplied by isolated systems. We also consider this approach as being inconsistent with the Queensland Government's definition of the UTP for 2019–20.

Energy Queensland supported basing notified prices for large business customers on the costs of supply in Ergon Distribution's east pricing zone, transmission region one.

Canegrowers Isis was of the view that:

> large business customers in South-East Energex area should not have a competitive advantage over Ergon customers as this will negatively impact and effectively stifle regional development and regional growth.
>
> …
>
> In our view we should use the Ergon tariff structure for large customers, but Energex prices should be applied as per small customers.[32]

QCA position

Our draft decision is to continue basing the notified prices for large business customers in regional Queensland on the lowest costs of supply in regional Queensland, which is Ergon Distribution's east pricing zone, transmission region one. We also propose to continue estimating the costs of supply for each retail tariff in accordance with an N+R cost build-up approach. This is consistent with our approach to setting notified prices for residential and small

[31] QCOSS, sub. 10, p. 1-2.
[32] Canegrowers Isis, sub. 3, p. 2.

business customers. We consider the effect of our decisions on competition, including the need for a headroom allowance, in the large business customer market in detail in Chapter 6.

3 NETWORK COSTS

Electricity network costs are regulated by the Australian Energy Regulator (AER), including the revenues and prices electricity distributors and transmission network service providers charge in relation to these costs.[33] *The QCA ensures these costs are appropriately incorporated into the regulated retail tariffs via the network cost component of the notified prices.*

The delegation requires the QCA to consider incorporating network service charges in a way that is generally consistent with the approach applied in previous determinations, including when deciding the network cost levels and tariff structures to apply.

This chapter sets out the QCA's draft determination on network service charges. Generally network costs have remained at a consistent level, contributing (on average) around the same cost to a typical customer's annual electricity bill as they contributed in 2018–19.

3.1 Introduction

A retailer incurs network costs when electricity is supplied to its customers. Network costs are the costs associated with transporting electricity through transmission and distribution networks.

Under the network plus retail (N+R) cost build-up approach that the QCA uses to set notified prices, the network cost component is treated as a pass-through. However, to determine the amount of the network cost to be passed through to retail customers, we need to determine:

(a) the level at which network charges should be set (i.e. Energex or Ergon Distribution levels)

(b) the network tariff structure on which the network cost component should be based (i.e. Energex or Ergon Distribution tariff structures).

Network tariff structures can include, for example, combinations of fixed, usage and demand charges. Consistent with our previous price determinations, the network cost components of regulated retail tariffs are based on the network tariff structures and pricing provided by Energex and Ergon Distribution (the distributors).

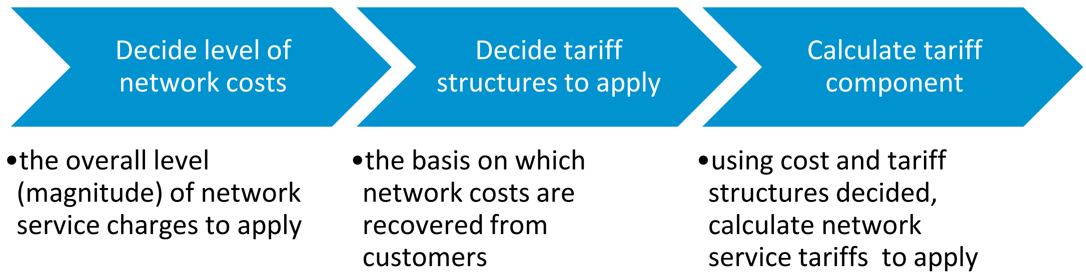
Network tariff structures and charges are established by the distributors and approved by the AER. As the timing of our price determination does not fully align with the AER's network pricing review process, the distributors have provided us with draft network prices.

Consequently, it is important to note the draft network prices provided to the QCA are preliminary and subject to change (distributors may update these before submitting them to the AER in March 2019).

The network cost components for the final determination will be based on the network pricing submitted to the AER. In the event that the final network tariffs approved by the AER differ from those submitted by the distributors, the QCA will consider using a cost pass-through mechanism to reflect any difference (see Chapter 6 for more information on this mechanism).

The process for determining network costs has three key stages:

[33] Powerlink, Energex Distribution (Energex) and Ergon Distribution establish network costs for approval as part of the AER's regulatory process.



The QCA's consideration of network costs is sequenced as follows:

- residential, small business and unmetered supply customers (section 3.2)
- large businesses, very large businesses and street lighting customers (section 3.3)
- summary of draft determination outcomes (section 3.4).

3.2 Residential, small business and unmetered supply customers

3.2.1 Level of network costs

In determining the network cost components of small customer and unmetered supply[34] retail tariffs, the first issue the QCA must consider is the level at which network cost components should be set (i.e. Energex or Ergon Distribution price levels).

For the 2019–20 price determination, the delegation requires that we consider basing the network cost component on:

- Energex network charges for residential and small business retail tariffs, including:
  - Non time-of-use retail tariffs (tariffs 11, 20, 31, 33, 41 and 91)
  - time-of-use and demand tariffs (tariffs 12A, 14, 15, 22A and 24).

Stakeholders broadly agreed that the approach outlined in the delegation was appropriate, both in terms of consistency with previous determinations and to ensure electricity prices for regional customers broadly reflect the prices customers pay in south east Queensland.[35]

QCA position

The QCA's draft decision is to use Energex network service costs as a basis for setting the network cost component of retail tariffs.

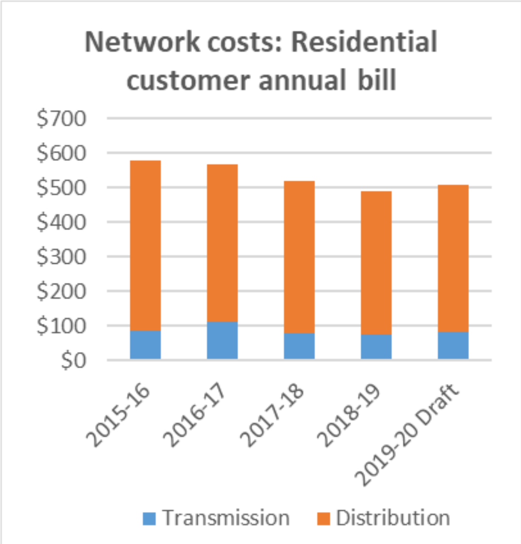
This approach is appropriate, as it aligns with the government's Uniform Tariff Policy (UTP), by using the level of network costs applied in south east Queensland. Also, it provides consistency and certainty for regional customers, by using the approach outlined in the delegation and applied by the QCA in previous price determinations.

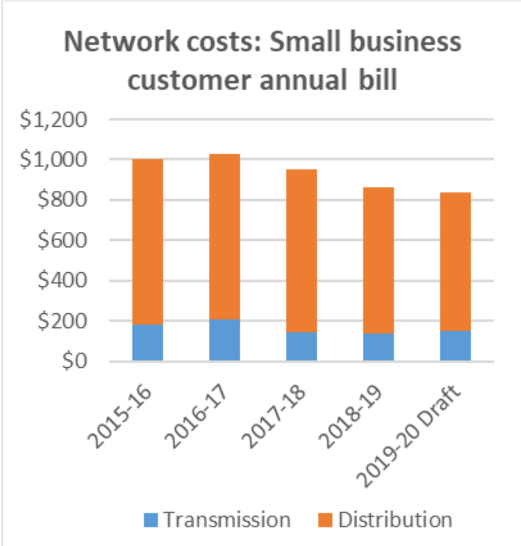
The QCA considered alternative options but decided they were not appropriate. In the case of network service charges, most options result in higher network costs being passed through to regional customers. This would produce an outcome inconsistent with the government's UTP, including the ongoing arrangements for subsidising electricity costs for regional customers.

[34] Unmetered supply retail tariff referred to in this chapter excludes street lighting–related services.
[35] Origin Energy, sub. 8, p. 1, Energy Queensland, sub. 5, section 2.1, Queensland Consumers' Association, sub. 11, p. 1, Kalamia, sub. 6, p. 2, Canegrowers Isis, sub. 3, p. 1. QCOSS, sub. 10, p. 1.

Furthermore, the chosen approach is generally supported by stakeholders and will result in small customers in regional Queensland generally paying the same for network services as small customers in south east Queensland.

The QCA notes network service costs have not changed significantly from 2018–19. Based on the draft network service costs available to the QCA, overall network service costs are around 3 per cent higher in 2019–20 for a typical residential customer[36] (around $16 more over the year), and 3 per cent lower for a typical small business customer[37] (around $24 less over the year) (see charts below).





3.2.2 Tariff structures

The second issue for the QCA to consider is whether to adopt the network tariff structures of Energex or Ergon Distribution for small customer and unmetered supply retail tariffs.

Both distributors offer a variety of network tariffs with different tariff structures, such as flat rate, time-of-use and time-of-use demand tariffs (see Appendix D for more detail on the tariff structures and differences between Energex and Ergon Distribution tariff structures).

The delegation directs us to consider adopting:

- Energex network tariff structures for non time-of-use retail tariffs (11, 20, 31, 33, 91[38], 41[39])
- Ergon Distribution network tariff structures for time-of-use and demand retail tariffs (12A, 14, 15, 22A, 24).

The QCA notes tariff 15 (the lifestyle tariff), introduced in 2018–19, is included in the delegation for consideration in a manner consistent with the time-of-use and demand retail tariffs.

While some stakeholders said adopting Ergon tariff structures for all retail tariffs may provide stronger price signals[40], stakeholders broadly supported using the approach outlined in the

[36] A typical residential customer on tariff 11.
[37] A typical small business customer on tariff 20.
[38] Excluding street lighting (tariff 71).
[39] Tariff 41 is a low voltage demand retail tariff available to small business customers in regional Queensland. It has fixed, usage and demand charges and is based on an Energex network tariff (network tariff code: 8300). Ergon Distribution does not have an equivalent network tariff available for small customers.
[40] Energy Queensland, sub. 5, section 2.1, Canegrowers Isis, sub. 3, p. 2, Kalamia, sub. 6, p. 2.

delegation. Stakeholders particularly supported using the Ergon Distribution tariff structure for time-of-use and demand retail tariffs, given the stronger price and cost signals and optionality to accommodate different customers' demand requirements.[41]

Two matters that stakeholders raised require additional consideration.

The first matter is about network services charges in relation to tariff 15. Some stakeholders supported the approach outlined and others considered it too complex:

- Energy Queensland strongly supported the approach outlined in the delegation on the basis the approach would maintain appropriate price signals. It noted other approaches may distort long-run marginal cost (LRMC) drivers inherent in the tariff structure and ultimately impact any results of testing the tariff—which will be offered to customers in 2019–20.[42]
- QCOSS expressed broader concerns around the complexity of the tariff structure and potential impacts (e.g. bill shock) on customers that would result. It said the trial should be extended and improvements made to ensure customers are no worse off, or are compensated for any detriments.[43]

The second matter concerns a suggestion Origin Energy made in relation to determining the network cost component for Essential Energy customers:

> [T]hese customers remain connected to a NSW distribution network and therefore are assigned a NSW network tariff. For those customers on a flat tariff, this does not pose any problems. For customers on time of use or controlled tariffs this is problematic …
>
> … Essential Energy charging intervals differ from the charging intervals historically set by the QCA for time of use tariff 12A and controlled load tariffs 31 and 33. Because Origin has no visibility of a customer's actual usage intervals, it is not possible to charge these customers the notified prices during the QCA set intervals.[44]

Origin Energy suggested that the QCA consider establishing tariffs with charging intervals aligned to those used by Essential Energy. This would allow Origin Energy to charge customers notified prices during time windows aligned to Essential Energy, and would provide price signals to these customers on the network costs that retailers incur.[45]

QCA position

The QCA's draft decision is to use Energex network tariff structures for non-time-of-use retail tariffs and Ergon Distribution network tariff structures for time-of-use and demand retail tariffs, including for tariff 15 (discussed separately below).

This approach is appropriate, as it ensures:

- for non time-of-use retail tariffs—Energex tariff structures are retained; these tariff structures are less complex and use flat rate and controlled load retail tariffs for small customers. It provides consistency and certainty for customers currently on these retail tariffs (including by reflecting the approach applied in previous determinations)
- for time-of-use tariffs—Ergon Distribution tariff structures are retained; these tariff structures are more cost-reflective, enhance underlying network price signals and encourage

[41] Origin Energy, sub. 8, p. 2, Energy Queensland, sub. 5, section 2.1. Canegrowers Isis, sub. 3, p. 2.
[42] Energy Queensland, sub. 5, section 2.1.
[43] QCOSS, sub. 10, p. 3.
[44] Origin Energy, sub. 8, p. 4.
[45] Origin Energy, sub. 8, p. 4.

customers to reduce usage during peak periods. It provides consistency and certainty for customers currently on these retail tariffs (including by reflecting the approach applied in previous determinations).

The QCA considered alternative options but decided they are not appropriate at this time. While the Energex tariff structures are less complex and do not contain strong price signals, the QCA nonetheless considers it is appropriate to retain these tariff structures for non-time-of-use retail tariffs. Using this tariff structure ensures consistency with the government's UTP, and provides stability and certainty to customers currently on non-time-of-use retail tariffs.

Tariff 15

The QCA's draft decision is to use Ergon Distribution network tariff structures for tariff 15 (the lifestyle tariff), which is consistent with the delegation.

This approach is appropriate, as it ensures:

- consistency and certainty, by applying the tariff structure used in the 2018–19 price determination (when this tariff was introduced)
- the network tariff structure is cost-reflective, enhancing the underlying network price signals and encouraging customers to reduce usage during peak periods[46]
- consistency with the government's intention to ensure regional customers have more choice in products (while maintaining the UTP).

The QCA considered the concerns raised by QCOSS and accepts the tariff structure involves additional complexity. In addition, the QCA accepts this complexity may make it difficult for customers who consider going onto tariff 15 to accurately calculate the impact on their annual electricity costs.

However, when this tariff was introduced, the QCA noted the impact of tariff 15 on customers (when compared to a flat rate non-time-of-use retail tariff) would depend on a range of factors, including an individual customer's consumption levels—particularly the consumption during the summer peak window—and whether consumption remained within the nominated band limit. In addition, the QCA noted customers most likely to benefit from this tariff were those with low consumption during the summer peak window, but high overall consumption levels.

The QCA considers these considerations remain important for customers and that, as with any tariff decision, customers should ensure they understand the tariff and charging structure, including whether they have the ability to manage and monitor their consumption during the summer peak window, before moving from their current charging structure onto tariff 15.

Essential Energy customers

The QCA considered the concerns raised by Origin Energy regarding the different charging windows Essential Energy has for its network charges, compared with those applied in the relevant notified tariffs based on network charges in south east Queensland.

This matter is addressed in detail in Chapter 6.

[46] Detailed information on this tariff is contained in the QCA's 2018–19 price determination, available on the QCA's website at http://www.qca.org.au/getattachment/5c1d8628-ae15-476e-937b-d07a92f5f4a7/Final-determination-regulated-retail-electricity-p.aspx .

3.2.3 Network cost component calculation and adjustment

For time-of-use and demand retail tariffs, the QCA needs to make an adjustment to ensure network charges are set at Energex price levels (see section 3.2.1), while retaining the Ergon Distribution tariff structures and price signals (see section 3.2.2). In contrast, this adjustment is not required for non-time-of-use tariffs, where network charges reflect a straight pass-through of Energex price levels and network tariff structures.

The table below sets out a summary of the QCA's adjustments for each of the relevant retail tariffs, and Appendix D contains further information.

Table 1 Summary of adjustments required to time-of-use and demand retail tariffs

Retail tariff	Description of adjustment made
Residential seasonal time-of-use tariff (tariff 12A)	Adopting Ergon Distribution usage cost components, and reducing the Ergon Distribution fixed cost component towards Energex price levels
Small business seasonal time-of-use retail tariff (tariff 22A)	Adopting the Energex fixed cost component, and reducing Ergon Distribution usage cost components towards Energex price levels
Residential and small business seasonal time-of-use demand tariffs (tariffs 14 and 24)	Uniformly decreasing the Ergon Distribution fixed, usage and demand cost components towards Energex price levels

The QCA's approach to adjusting network charges in this review is consistent with that applied in the previous determinations. In particular, we have adopted different adjustment approaches for the time-of-use and demand retail tariffs to ensure our adjustments result in network prices that are:

- equivalent to the Energex network costs that are before the AER for approval
- calculated in a way that preserves the price signals of Ergon Distribution tariff structures by, to the extent possible, retaining the relativities between different pricing components.

The resulting network tariffs ensure that residential, small business and unmetered supply customers will, on average, pay the same as they would on a retail tariff in south east Queensland.

Tariff 15 adjustment

For tariff 15 (the lifestyle tariff), the QCA needs to make an adjustment to ensure network charges are set at Energex price levels, while retaining the Ergon Distribution tariff structure and price signals.

The QCA's approach to adjusting the network charges for tariff 15 is different to that applied in the 2018–19 price determination. In particular, we now have more information on how the network tariff structure and components are derived in order to make the necessary adjustment.

Using the network charges of the Ergon lifestyle tariff, Energy Queensland proposed the following adjustment in order to derive a UTP-consistent network charge:

- Reduce the network charges of charging components used to recover residual costs, such that the total network revenue recovered under the Ergon lifestyle tariff would be the same as revenue recovered under the Energex lifestyle tariff.

- Leave the network charges that reflect the LRMC signals unchanged.[47]

Importantly, Energy Queensland said the approach also retains the LRMC signals of the Ergon lifestyle tariff.

The QCA considers that Energy Queensland's proposed methodology for the network charges is appropriate to be used in the QCA's price determination, as the network charges are UTP-consistent and adjustments achieve the desired intent (e.g. to retain LRMC price signals).

While the tariff is yet to be approved by the AER for 2019–20, Energy Queensland has indicated Ergon Distribution's proposal will be consistent with this approach.

On this basis, the QCA's draft determination incorporates the adjustments, as proposed by Energy Queensland, to determine the network charges for tariff 15. Additional information on the tariff structure and charging windows is shown in Table 6 (section 1.4).

3.3 Large business, very large business and street lighting customers

This section discusses the QCA's approach to setting network cost components of retail tariffs for large business, very large business and street lighting customers.[48]

For the 2019–20 price determination, the delegation directs us to consider, for large business customers[49], basing the network cost component on the network charges to be levied by Ergon Energy.

This approach results in network costs and tariff structures applicable in Ergon Distribution's east pricing zone, transmission region one being applied to high voltage retail tariffs:

- Connection Asset Customers (CACs) (tariffs 51A to 51D, 52A to 52C)—underpinned by Ergon Distribution CAC standard network tariffs and CAC seasonal time-of-use demand (STOUD) network tariffs
- Individually Calculated Customers (ICCs) (tariff 53)—underpinned by the Ergon Distribution CAC standard network tariff HVL (High Voltage Line–22/11kV Line).

Most stakeholders supported maintaining this approach.[50]

However, Canegrowers Isis commented on the level of network costs applied to large business customers. It said:

> [C]ustomers in south east Energex area should not have a competitive advantage over Ergon customers, as this would negatively impact and effectively stifle regional development and regional growth.

On that basis, Canegrowers Isis said the Ergon tariff structures for large customers should be used, but Energex prices should be applied as per small customers.[51]

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[47] Energy Queensland, sub. 5, supplemented by additional information provided on a confidential basis (including financial calculations related to the tariff adjustment).
[48] Large business customers are Standard Asset Customers (SACs) (large), typically consuming more than 100 MWh but less than 4 GWh per annum. Very large business customers consist of Connection Asset Customers (CACs), typically consuming more than 4 GWh but less than 40 GWh per annum and Individually Calculated Customers (ICCs), typically consuming more than 40 GWh per annum.
[49] Consuming 100 MWh or more per annum.
[50] Energy Queensland, sub. 5, section 2.1.
[51] Canegrowers Isis, sub. 3, p. 2.

In addition, Energy Queensland advised that among the non-site-specific network tariffs, the CAC standard network tariff HVL is the closest to cost reflectivity for ICCs on a network level. Therefore, we should continue to base the ICC retail tariff on the CAC standard network tariff HVL.

QCA position

The QCA's draft decision is to base retail tariffs for large and very large business customers, as well as for street lighting customers, on the network tariffs and charges applicable in Ergon Distribution’s east pricing zone, transmission region one, which is consistent with the delegation.

This approach is appropriate as it aligns with the government's UTP, by using network costs of east zone, transmission region one, which has the lowest cost of supply among the Ergon Distribution pricing regions connected to the National Electricity Market. In addition, it provides consistency and certainty for regional customers, by using the approach outlined in the delegation and applied by the QCA in previous price determinations.

The QCA accepts the approach put forward by Energy Queensland in respect of the ICC retail tariff. The QCA is satisfied this approach, consistent with other tariffs determined for high voltage customers more broadly, is the closest tariff on which to base the ICC tariff in terms of cost reflectivity. Also, the approach produces an outcome aligned with the government's UTP and provides consistency and certainty by using the approach applied by the QCA in previous price determinations.

The QCA considered alternative options but decided they are not appropriate. In the case of network service charges cost levels, applying the approach suggested by Canegrowers Isis would produce an outcome inconsistent with the government's UTP, the delegation and the approach applied in previous determinations.

Furthermore, the approach is generally supported by stakeholders and has been shown to have broader benefits in improving market conditions in regional Queensland for these customers. For instance, an increasing number of large and very large customers in Ergon Distribution's east pricing zone, transmission region one have transitioned from notified prices to market offers.

The QCA notes network service costs have remained around the same when compared to the level of costs included in network costs in the previous determination, with minor increases or decreases in overall costs.

3.4 Summary of draft determination network charges

The following tables summarise the network charges by customer and tariff type for:

- residential and small business customers on:
  - non-time-of-use tariffs (Table 2)
  - time-of-use and demand tariffs (Table 3)
  - lifestyle tariff 15 (Table 4)
- large business customers (Table 5)
- very large business customers (Table 6).

Table 2 Network charges for 2019–20 for residential customer retail tariffs (GST exclusive)

Retail tariff	*Energex network tariff code*	*Fixed charge[a] c/day*	*Usage charge c/kWh*	*Demand charge $/kW/mth*
Tariff 11—Residential (flat rate)	8400	49.000	8.762	
Tariff 20—Business (flat rate)	8500	66.500	8.663	
Tariff 31—Night rate (super economy)	9000		6.421	
Tariff 33—Controlled supply (economy)	9100		6.736	
Tariff 41—Low voltage (demand)[b]	8300	462.100	0.796	18.956
Tariff 91—Unmetered	9600		6.630	

a *Charged per metering point.*

b *The kVA equivalent demand charge for tariff 41 is $17.244/kVA/month. A conversion factor of 0.9097 has been used, as advised by Energex.*

Table 3 Network charges for 2019–20 for residential customer retail tariffs (GST exclusive)

Retail tariff	*Fixed charge[a] c/day*	*Usage charge (peak) c/kWh*	*Usage charge (off-peak or flat) c/kWh*	*Demand charge (peak) $/kW/mth*	*Demand charge (off-peak) $/kW/mth*
Tariff 12A—Residential (seasonal time-of-use)	42.185	41.421	5.136		
Tariff 22A—Business (seasonal time-of-use)	66.500	38.766	7.376		
Tariff 14—Residential (seasonal time-of-use demand)	5.473		1.763	52.802	7.583
Tariff 24—Business (seasonal time-of-use demand)	5.728		2.298	68.678	6.901

a *Charged per metering point.*

Table 4 Network charges for 2019–20 for retail tariff 15 (GST exclusive)

Retail tariff	*Fixed charge (Band 1)[a] $/mth*	*Fixed charge (Band 2)[b] $/mth*	*Fixed charge (Band 3)[c] $/mth*	*Fixed charge (Band 4)[d] $/mth*	*Fixed charge (Band 5)[e] $/mth*	*Usage charge c/kWh*	*Summer peak top-up charge[f] $/kWh/mth*
Tariff 15—Residential lifestyle	13.242	28.872	44.501	60.130	75.759	1.663	8.252

a *Band 1 (no network access allowance included during the summer peak window (SPW), where the SPW is defined as November to March, any day between 4 pm and 9 pm).*

b *Band 2 (up to 5 kWh network access allowance included during the SPW).*

c *Band 3 (up to 10 kWh network access allowance included during the SPW).*

d *Band 4 (up to 15 kWh network access allowance included during the SPW).*

e *Band 5 (up to 20 kWh network access allowance included during the SPW).*

f *The summer peak top-up charge is applicable to the single maximum daily energy consumed above the limit of the customer's nominated access band during the month. This top-up charge is only applicable to network use during the SPW, i.e. November to March, any day between 4 pm and 9 pm. Once the network access allowance for the chosen band has been exceeded, the exceeded amount (in kWh) remains available for the customer for the rest of the month until the allowance is reset back to the original nominated allowance at the start of the coming month.*

Table 5 Network charges for 2019–20 large business and street lighting customer retail tariffs (GST exclusive)

Retail tariff	*Ergon Distribution network tariff code*	*Fixed charge[a] c/day*	*Usage charge (peak) c/kWh*	*Usage charge (off-peak/flat) c/kWh*	*Demand charge (peak) $/kW/mth*	*Demand charge (off-peak/flat) $/kW/mth*
Tariff 44—Over 100 MWh small (demand)	EDSTT1	3982.100		1.298		32.601
Tariff 45—Over 100 MWh medium (demand)	EDMTT1	13555.600		1.298		24.118
Tariff 46—Over 100 MWh large (demand)	EDLTT1	35674.400		1.288		19.760
Tariff 50—Seasonal time-of-use (demand)	ESTOUDCT1	3058.500	0.978	3.205	60.047	10.459
Tariff 71—Street lighting[b]	EVUT1	0.400		15.673		

a *Charged per metering point.*

b *The fixed charge for street lighting applies to each lamp.*

Table 6 Network charges for 2019–20 very large business customer retail tariffs (GST exclusive)

Retail tariff	*Ergon Distribution network tariff code*	*Fixed charge c/day*	*Usage charge (peak) c/kWh*	*Usage charge (off-peak or flat) c/kWh*	*Connection unit charge $/day/unit*	*Capacity charge (off-peak/flat) $/kVA of authorised demand/mth*	*Demand charge (peak/flat) $/kVA/mth*	*Excess reactive power charge $/excess/kVAr/ mth*
Tariff 51A—Over 4 GWh high voltage (CAC 66kV)	EC66T1	19253.400		1.350	9.285	4.077	2.460	4.000
Tariff 51B—Over 4 GWh high voltage (CAC 33kV)	EC33T1	12688.400		1.350	9.285	5.006	2.535	4.000
Tariff 51C—Over 4 GWh high voltage (CAC 22/11kV Bus)	EC22BT1	11274.400		1.354	9.285	5.827	3.075	4.000
Tariff 51D—Over 4 GWh high voltage (CAC 22/11kV Line)	EC22LT1	10466.400		1.372	9.285	11.413	6.201	4.000
Tariff 52A—Over 4 GWh high voltage (CAC STOUD 33/66kV)	EC66TOUT1	7133.400	0.919	1.288	9.285	6.237	11.000	4.000
Tariff 52B—Over 4 GWh high voltage (CAC STOUD 22/11kV Bus)	EC22BTOUT1	7133.400	0.923	1.292	9.285	4.392	41.435	4.000
Tariff 52C—Over 4 GWh high voltage (CAC STOUD 22/11kV Line)	EC22LTOUT1	7133.400	0.941	1.310	9.285	8.082	72.333	4.000
Tariff 53—Over 40 GWh high voltage (ICC)[a]	EC22LT1	10466.400		1.372		11.413	6.201	4.000

a *Ergon Distribution advised that ICCs do not incur connection unit charges on a network level.*

4 ENERGY COSTS

A retailer incurs energy costs when purchasing electricity to meet the electricity demand of its customers. Energy costs can be separated into three general components:

- *wholesale energy costs*
- *other energy costs*
- *energy losses.*

As with previous price determinations, the QCA has determined energy costs based on advice from ACIL Allen, its consultant. ACIL Allen has estimated that energy costs will decrease for all customers in 2019–20, with decreases primarily driven by lower wholesale energy costs and large-scale renewable energy target (LRET) costs.

This chapter gives an overview of how each of the three energy cost components was estimated. A more detailed explanation is available in ACIL Allen's draft report, which also responds to issues around energy costs raised in stakeholder submissions.[52]

4.1 Wholesale energy costs

A retailer incurs wholesale energy costs when purchasing electricity from the National Electricity Market (NEM) to meet the electricity demand of its customers. The NEM is a volatile market where spot prices are settled every half an hour and currently can range from –$1000 to $14,500 per megawatt hour (MWh).[53]

Retailers can, and do, adopt a range of strategies to reduce spot price volatility risk, including:

- pursuing a hedging strategy by purchasing financial derivatives[54]—such as futures, swaps, caps and options
- entering long-term power purchase agreements with generators
- investing in their own electricity generators.

Since the 2012–13 price determination, ACIL Allen has estimated wholesale energy costs for customers on notified prices using a market hedging approach, which takes into account retailers' hedging strategies. Such an approach has also been adopted by other Australian regulators[55] to estimate energy costs and has been endorsed by the Australian Energy Market Commission (AEMC) in its 2013 advice on best practice retail regulation.[56]

[52] ACIL Allen, February 2019, chapter 3.

[53] The minimum spot price (market floor price) and the maximum spot price (market price cap) are defined in chapter 3 of the National Electricity Rules. The market price cap is published by the AEMC every February and is effective from 1 July. For more information, see www.aemc.gov.au.

[54] Generally, purchasing financial derivatives enables retailers to lock in a price, or a maximum price (in the case of caps) at which a given volume of electricity will be transacted at a future date.

[55] The Independent Competition and Regulatory Commission and the Office of the Tasmanian Economic Regulator.

[56] AEMC, September 2013.

For the 2019–20 price determination, we engaged ACIL Allen to estimate wholesale energy costs for customers settled on:

- the net system load profiles (NSLPs) in the Energex and Ergon distribution areas
- the controlled load profiles (CLPs) in the Energex distribution area.

The NSLP and CLP approximate how much electricity is consumed by customers on accumulation meters[57] in a region, for each half hour of the day. At this stage, most customers in Queensland are on accumulation meters. There are currently two types of CLPs in the Energex distribution area—CLP 9000 and CLP 9100—which capture the consumption profiles of customers on retail tariffs 31 and 33 respectively.

In its submission to the QCA, Origin Energy[58] requested that the QCA:

- ensures that modelled load profiles and pool price simulations reflect the variability of outcomes experienced in the NEM over an extended period
- considers the appropriate hedging strategy to be modelled considering a tighter supply/demand balance and continued reduction in 'middle of day' demand due to solar penetration.

Energy Queensland raised similar issues and suggested the QCA takes into account:

> the significant new renewable energy generation connected, or about to be connected, to the National Electricity Market (NEM), and the impact on the wholesale electricity market.
>
> When combined with additional renewable generation due to come on line in 2019, Energy Queensland expects that wholesale prices in the middle of the day will be further suppressed, resulting in higher evening prices as other forms of generation make up for lost daytime revenue in the evening peak period.
>
> …
>
> Energy Queensland considers that the methodology developed by consultants ACIL Allen to determine wholesale energy costs should capture these effects.[59]

ACIL Allen demonstrated that its methodology adequately addresses Origin Energy's and Energy Queensland's concerns by using the latest available market data to estimate wholesale spot prices and hedged energy costs. These issues are addressed in detail in chapter 3 of ACIL Allen's draft report.

ACIL Allen has continued to estimate wholesale energy costs using a market hedging approach. This approach is designed to simulate the wholesale energy market from a retailer's perspective. It involves simulating expected spot prices and a retailer that hedges spot price risk by purchasing financial derivatives with contract prices represented by the observable ASX Energy futures[60] market data. A detailed explanation of how wholesale energy costs were estimated is in chapter 4 of ACIL Allen's draft report.

[57] Unlike smart/interval meters, accumulation meters do not record when during the day electricity was consumed or how much was consumed at that time. To allow for half-hourly settlement within the NEM (with different spot prices and volume for each half hour), AEMO uses the NSLP to approximate the amount of electricity consumed by customers on accumulation meters in a region, for each half hour of the day.
[58] Origin Energy, sub. 8.
[59] Energy Queensland, sub. 5.
[60] ASX energy futures are exchange-traded energy financial derivatives, which allow retailers to reduce the spot price volatility risk when purchasing electricity from the NEM. For more information, see https://www.asxenergy.com.au/.

Compared to the estimates for the 2018–19 price determination, ACIL Allen estimated that wholesale energy costs for 2019–20 will:

- **decrease** for customers settled on the **Energex NSLP**, **Ergon NSLP** and **Energex CLP 9100**. This decrease reflects the projected decrease in spot price volatility in Queensland and other NEM regions—resulting from the expected entry of approximately 5200 MW of utility-scale solar and wind generation into the NEM. Of the 5200 MW new capacity, 1350 MW is committed to enter the Queensland market. ACIL Allen also attributed the projected decrease in price volatility to the Queensland Government's directive to establish CleanCo[61] from 1 July 2019. The key impact of CleanCo on wholesale energy costs is the change in operation of the Wivenhoe pumped storage hydroelectric plant, where Wivenhoe is expected to operate more aggressively, reflecting its position in the new and smaller generation portfolio of CleanCo[62] (see section 4.1.3).
- **increase** for customers settled on the **Energex CLP 9000**. This increase is primarily driven by the load requirement and pattern[63] of the Energex CLP 9000. About 65 per cent of the load requirements for the Energex CLP 9000 occur between 10 pm and 2 am (see section 4.1.1). ACIL Allen's modelling estimated that wholesale prices during these periods are not decreasing, given that the entry of substantial utility-scale renewable generation and the operation of Wivenhoe do not impact upon prices during these periods.

ACIL Allen estimated that wholesale energy costs in 2019–20 will:

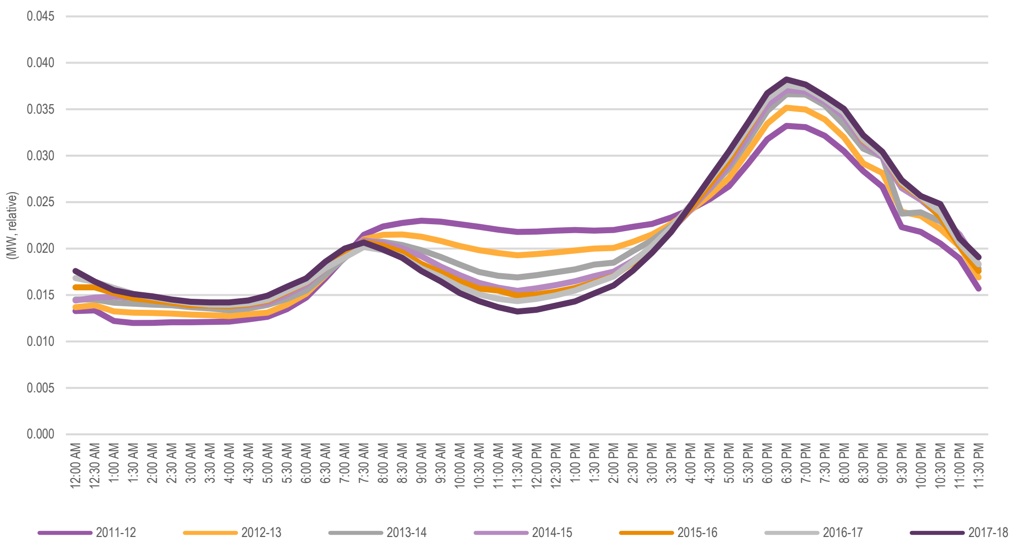
- decrease by 10.1 per cent to $89.08/MWh for the Energex NSLP
- decrease by 14.5 per cent to $75.39/MWh for the Ergon NSLP
- increase by 5.9 per cent to $64.89/MWh for the Energex CLP 9000 (retail tariff 31)
- decrease by 7.8 per cent to $72.49/MWh for the Energex CLP 9100 (retail tariff 33).

4.1.1 Demand profiles and historical energy cost levels

Over the past few years, the Energex and Ergon NSLPs have become 'peakier', due to increased penetration of rooftop solar photovoltaic, which has reduced daytime demand but has had limited effect on the evening peak demand (Figures 10 and 11). On the Energex NSLP, more electricity from the grid is consumed during peak periods than on other demand profiles. Consequently, the Energex NSLP has the highest wholesale energy costs of the profiles analysed in Queensland. The Ergon NSLP is less peaky than the Energex NSLP and consequently has lower wholesale energy costs.

[61] The Queensland Government has restructured its government-owned generators and established a separate entity, CleanCo, to operate its existing renewable energy generation assets and develop new renewable energy projects.
[62] The CleanCo generation portfolio will consist of the Wivenhoe pumped storage facility, Barron Gorge, Kareeya and Koombooloomba hydro generators, and the Swanbank E gas-fired power plant.
[63] The load requirement and pattern of the Energex CLP 9000 are controlled by Energex through the management of its network tariff—NTC 9000 Super Economy. Under this network tariff, Energex ensures that the supply of electricity is available for a minimum of eight hours per day. Energex manages the load for this network tariff such that it maintains customer comfort, maximises utilisation and minimises peak demand on the Energex network.

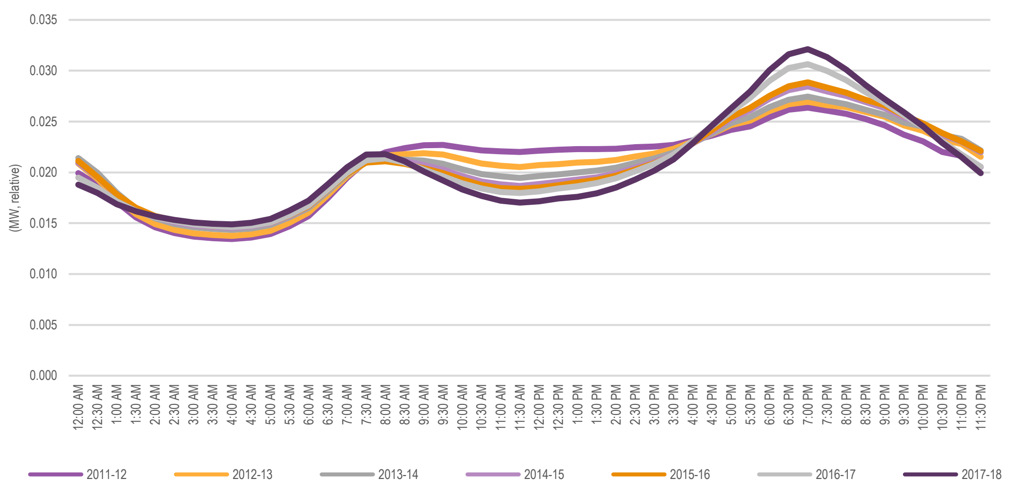
Figure 10 Energex NSLP



Note: 'Relative MW' means the annual loads for each profile have been scaled so they add up to one. This removes differences in absolute scale between the different profiles and changes in absolute size over time.

Source: ACIL Allen, February 2019.

Figure 11 Ergon NSLP

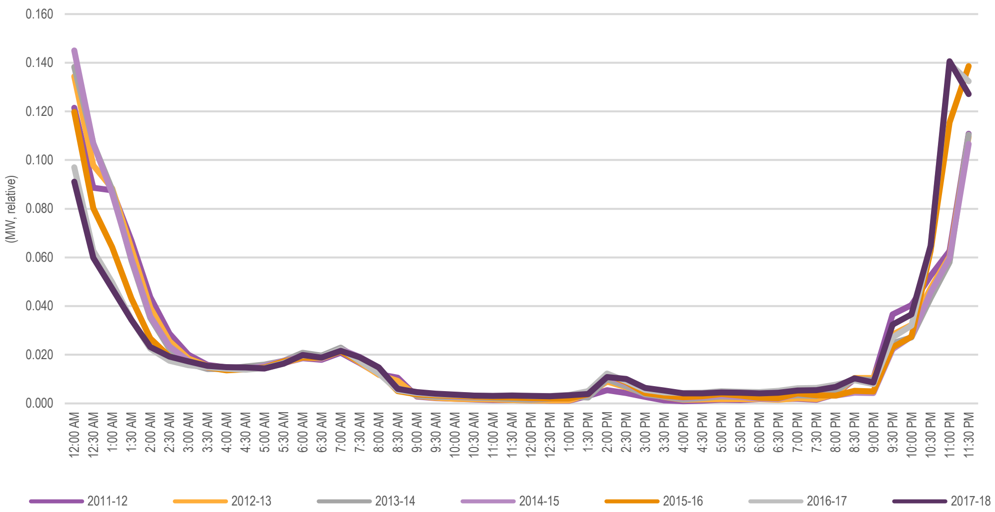


Note: 'Relative MW' means the annual loads for each profile have been scaled so they add up to one. This removes differences in absolute scale between the different profiles and changes in absolute size over time.

Source: ACIL Allen, February 2019.

On the Energex CLPs, more electricity is generally consumed during off-peak periods and non-summer quarters (due to higher water heating loads in non-summer months) than on the Energex and Ergon NSLPs. Therefore, the Energex CLPs have lower wholesale energy costs relative to the NSLPs. The Energex CLP for retail tariff 33 typically has a higher wholesale energy cost than the Energex CLP for retail tariff 31. This is because the former generally has relatively more electricity consumed during daylight hours and the evening peak than the latter. Figures 12 and 13 show the Energex CLPs.

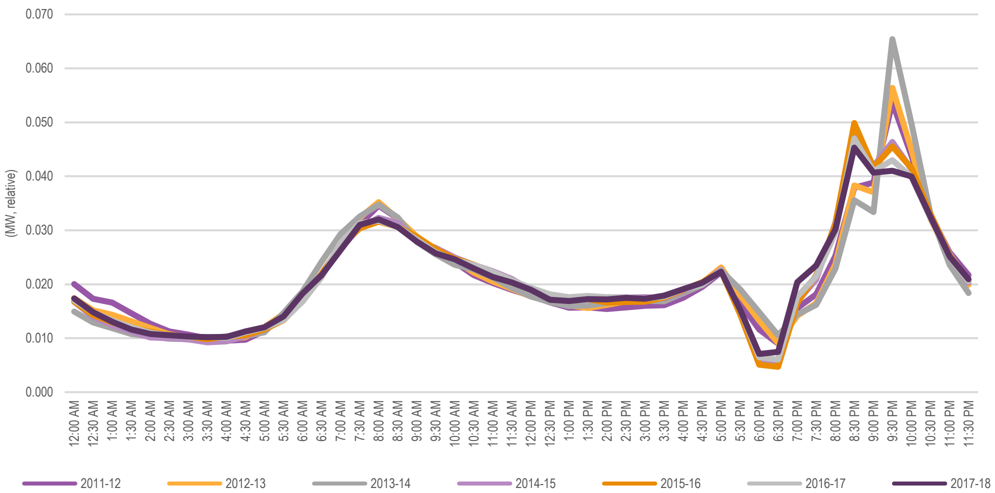
Figure 12 Energex CLP for retail tariff 31



Note: 'Relative MW' means the annual loads for each profile have been scaled so they add up to one. This removes differences in absolute scale between the different profiles and changes in absolute size over time.

Source: ACIL Allen, February 2019.

Figure 13 Energex CLP for retail tariff 33



Note: 'Relative MW' means the annual loads for each profile have been scaled so they add up to one. This removes differences in absolute scale between the different profiles and changes in absolute size over time.

Source: ACIL Allen, February 2019.

ACIL Allen advised that its wholesale energy market modelling broadly aligns with the market's expectations of spot price outcomes for 2019–20. ASX futures contract prices for 2019–20 (on a trade-weighted basis) have decreased for base, peak and cap contracts, compared to prices estimated for the 2018–19 final determination (see section 4.1.2). Generally, the purchase of ASX futures enables retailers to lock in a price, or a maximum price (in the case of caps), at which a given volume of electricity will be transacted at a future date. Therefore, futures contract prices incorporate market participants' risk-weighted expectations of future spot prices.

4.1.2 Estimating contract prices

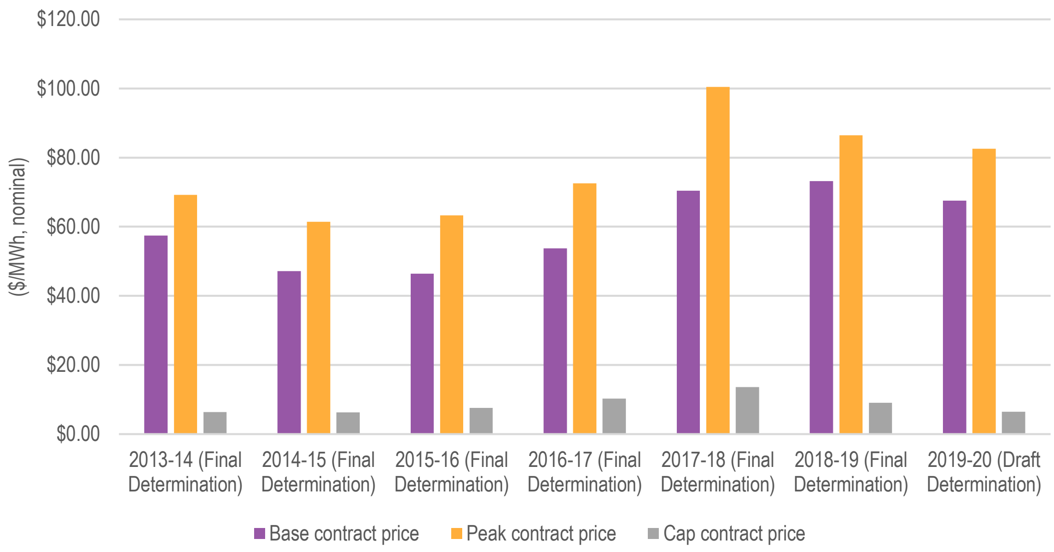
Contract prices for financial derivatives were estimated using the trade-weighted average of ASX Energy daily settlement prices of base, peak and cap contracts for 2019–20. To calculate the trade-weighted futures contract prices, ACIL Allen has used the contract prices and volume of contracts traded until 15 February 2019.

In addition to using actual contract data until 15 February 2019, ACIL Allen also refined its contract analysis to account for the potential contract prices and volume of contracts traded between 16 February and early April 2019.[64] For the final determination, actual ASX Energy futures data until early April 2019 will be used to estimate contract prices. More details on ACIL Allen's approach are available in chapter 4 of its draft report.

Compared to the contract prices estimated for the 2018–19 price determination, futures contract prices for 2019–20, on an annualised and trade-weighted basis, have:

- decreased by about $5.70/MWh for base contracts
- decreased by about $4.00/MWh for peak contracts
- decreased by about $2.60/MWh for cap contracts.

Figure 14 Annualised quarterly electricity futures contract prices ($/MWh), 2019–20 draft determination and previous final determinations



Source: ACIL Allen, February 2019.

ACIL Allen advised that this is a reflection of market participants expecting some softening in spot price outcomes and lower price volatility, due to:

- the large amount of renewable generation expected to enter service in 2019–20 (approximately 5200 MW of utility-scale solar and wind generation into the NEM, with 1350 MW committed to enter the Queensland market)
- the potential change in the operation of the Wivenhoe pumped storage facility due to the establishment of CleanCo.

[64] ACIL Allen assumed that retailers will complete their build-up of hedging contracts by early April 2019.

However, recent base contract prices have not fallen to the same extent as peak and cap contract prices. ACIL Allen advised that higher coal prices for some coal-fired generators in New South Wales and continuing strong gas prices have influenced the market's expectations and have therefore acted as a lower bound on base contract prices for 2019–20 to date.

4.1.3 Data extension

In the ICP, we proposed to extend the energy data cut-off date to the end of January for this draft determination, subject to the practicalities of doing so. Extending the data cut-off date would allow us to account for some of the developments within the NEM and energy financial markets that occurred over the summer period.

In their submissions to the QCA, Canegrowers Isis, Origin Energy and Energy Queensland supported extending the energy data cut-off date to the end of January.[65]

To account for the developments within wholesale energy related markets over the summer period to the greatest extent possible, while publishing the draft determination in February 2019, ACIL Allen extended the data cut-off date to 15 February 2019. The data cut-off date for the 2018–19 draft determination was mid-January 2018, but ACIL Allen has now included an additional month of data for contract prices and volume of contracts traded in its energy cost analysis for the 2019–20 draft determination.

In addition to extending the data cut-off date, ACIL Allen also refined its contract analysis to account for the potential ASX futures contract prices and volume of contracts traded between 16 February and early April 2019.[66] Actual ASX Energy futures data until early April 2019 will be used to estimate contract prices for the final determination.

This improvement in methodology could potentially reduce the variation in the wholesale energy cost estimates between the draft and final determinations.

4.1.4 Impact of CleanCo on wholesale energy costs

The Queensland Government has decided to restructure its government-owned generators and establish a separate entity, CleanCo, to operate its existing renewable energy generation assets and develop new renewable energy projects.

It is expected that CleanCo would operate the Wivenhoe pumped storage hydroelectric plant, Barron Gorge, Kareeya and Koombooloomba hydro generators, and the Swanbank E gas-fired power plant. ACIL Allen advised that the key impact of CleanCo for 2019–20 would be the potential change in the operation of Wivenhoe. Over the past decade, on an annual basis, Wivenhoe has operated its 500 MW generation capacity at a capacity factor[67] of around one per cent.

However, as part of a smaller generation portfolio, Wivenhoe is expected to operate more aggressively and ramp up during periods of high spot prices, which would likely place downward pressure on peak price outcomes. ACIL Allen has incorporated the potential impact of CleanCo in its energy market modelling for this draft determination.

[65] Canegrowers Isis, sub. 3; Origin Energy, sub. 8; Energy Queensland, sub. 5.
[66] ACIL Allen assumed that retailers will complete their build-up of hedging contracts by early April 2019.
[67] The capacity factor is the average power generated divided by the rated peak power. For example, if a power plant has a rated peak power of 5 MW and it produces power at an average of 2.5 MW, then its capacity factor is 50 per cent.

4.1.5 Comparison with the AEMC price trends report

In December 2018, the AEMC, with the assistance of Ernst & Young (EY), released a report on residential electricity price trends.[68] One of the key purposes of this report was to provide interested parties with an understanding of the expected trends in each of the cost components involved in supplying electricity over the period 2017–18 to 2020–21.

The AEMC noted that the price trends report does not provide, and should not be regarded as providing, forecasts of future prices. Considering the AEMC's timing requirements, data availability, and the need to ensure methodological consistency across estimates for different jurisdictions, the AEMC adopted a blended approach—based on observable market data and modelled estimates (if market data are unavailable)—to estimate costs.

In the AEMC's report, it is suggested that between 2018–19 and 2019–20 wholesale energy costs[69] will decrease by 25.6 per cent in south east Queensland.[70] This decrease is noticeably larger than the decreases estimated by ACIL Allen, which used a market hedging approach.

ACIL Allen advised that EY's approach to estimating wholesale energy costs is broadly similar to its approach. However, there are some key differences:

- Build-up period of retailers' portfolio of hedging contracts
  - EY's approach—EY assumed that small and large retailers build up their portfolio of hedging contracts over a 12-month and 2-year period respectively.
  - ACIL Allen's approach—ACIL Allen considered all contracts traded back to the first trade recorded in the ASX Energy database for a given hedging product and did not distinguish between small and large retailers. This approach reflects, in practice, the build-up period of contracts by retailers trading in ASX Energy futures.
- Build-up pattern of retailers' portfolio of hedging contracts, and contract prices
  - EY's approach—EY assumed that retailers build up their portfolio of hedging contracts in an exponential pattern and complete their build-up by April 2019. This approach, coupled with the fact that EY's analysis was completed in October 2018, has meant that six months of actual ASX Energy contract data (traded from October 2018 to April 2019) were not available to be included in EY's analysis for 2019–20. As a replacement for the six months of missing ASX Energy data, EY used its modelled estimates—based on forecast spot market outcomes and an assumed contract premium.
  - ACIL Allen's approach—to estimate contract prices, ACIL Allen used the observable trade volumes as weights to calculate the trade-weighted average ASX Energy futures prices for a given hedging product. ACIL Allen also assumed that retailers will complete their build-up of contracts by April 2019.[71] This approach, in effect, incorporates the timing and

[68] AEMC, December 2018.

[69] It is worth noting that EY's definition of the wholesale energy cost includes the costs of market operator fees, network losses and ancillary service charges, whereas ACIL Allen reports these elements separately from the wholesale energy cost.

[70] In the AEMC's report, it is suggested that wholesale energy costs for south east Queensland will decline to $66.40/MWh in 2019–20. This value is noticeably lower than ACIL Allen's estimate, which it arrived at by using a market-hedging approach.

[71] For the draft determination, ACIL Allen has used the actual contract prices and volume of contracts traded until 15 February 2019 to estimate contract prices. In addition to using actual contract data until 15 February 2019, ACIL Allen also refined its contract analysis to account for the potential ASX futures contract prices and

volume of actual contract purchases and reflects how retailers that trade in ASX Energy futures build up their portfolio of hedging contracts over time.

Rather than pre-specifying a particular pattern in the build-up of hedging contracts, ACIL Allen's methodology generally more closely reflects, in practice, how retailers build up their portfolio of hedging contracts over time. Furthermore, the ASX Energy futures market for the Queensland regional reference node is fairly actively traded due to the presence of large standalone generators and limited vertical integration among retailers and generators. Therefore, we consider that ACIL Allen's approach is more likely to produce robust estimates that better reflect the actual costs retailers incur when purchasing electricity from the NEM.

QCA position

The QCA considers ACIL Allen's market hedging approach:

- adequately takes into account the issues raised in submissions
- is transparent and likely to produce reliable estimates that best reflect the actual costs retailers incur when purchasing electricity from the NEM.

The QCA notes that maintaining an approach for 2019–20 that is largely consistent with the approach adopted in previous determinations will also provide certainty to stakeholders.

The QCA's draft decision is to accept ACIL Allen's advice on this matter and its wholesale cost estimates (outlined in Table 7).

To be consistent with the UTP, we propose to use the wholesale energy cost estimates of the Energex NSLP and CLPs for residential, small business and unmetered supply (excluding street lighting) customers (see Chapter 2).

Table 7 Estimated draft wholesale energy costs at the Queensland regional reference node, 2019–20

Settlement class	*Retail tariff*	*Wholesale energy cost*	*Change from 2018–19*	
		$/MWh	*%*	*$/MWh*
Energex NSLP and unmetered supply	11, 12A, 14, 15, 20, 22A, 24, 41, 91	$89.08	–10.1	–$10.02
Energex CLP 9000	31	$64.89	5.9	$3.63
Energex CLP 9100	33	$72.49	–7.8	–$6.17
Ergon Energy NSLP—SAC demand and street lighting	44, 45, 46, 50, 71	$75.39	–14.5	–$12.79
Ergon Energy NSLP—high voltage—CAC and ICC	51A, 51B, 51C, 51D, 52A, 52B, 52C, 53	$75.39	–14.5	–$12.79

Source: ACIL Allen, February 2019.

volume of contracts traded between 16 February and early April 2019. Actual ASX Energy futures data until early April 2019 will be used to estimate contract prices for the final determination.

4.2 Other energy costs

In addition to determining wholesale energy costs, the QCA must account for other energy costs that retailers incur when purchasing electricity from the NEM:

- renewable energy target (RET) costs
- NEM management fees[72] and ancillary services charges
- prudential capital costs.

4.2.1 Renewable energy target costs

The RET scheme, comprised of the large-scale renewable energy target (LRET) and small-scale renewable energy scheme (SRES), provides incentives for the electricity sector to increase generation from renewable sources and reduce greenhouse gas emissions. The costs of these incentives are paid by retailers through the purchase of large-scale generation certificates (LGCs) and small-scale technology certificates (STCs). Retailers surrender the purchased LGCs and STCs to the Clean Energy Regulator (CER) to meet their obligations under the RET scheme.

LRET costs

The LRET sets annual targets for the amount of electricity that must be sourced from large-scale renewable energy projects, such as utility-scale wind and solar generation. The mandated LRET for 2019 is 31,244 GWh, and for 2020 it is 33,850 GWh.[73]

Retailers must purchase a set number of LGCs according to the:

- renewable power percentage (RPP) published by the CER
- amount of electricity they have sold to customers in the calendar year.

For its advice on the 2018–19 price determination, ACIL Allen estimated LRET costs using a market-based approach. Under this approach, LRET costs for the relevant calendar years were estimated by multiplying the expected average LGC prices and RPP values. The LRET cost for the financial year was derived by averaging the two calendar-year estimates.

The expected average LGC prices were estimated using LGC forward prices published by the Australian Financial Markets Association (AFMA) and provided by TFS Australia (an energy brokerage company). The implied RPP value was estimated by dividing the LRET target by the implied total electricity consumed (projected by the CER). To calculate the implied total electricity consumption, ACIL Allen used the SRES data published by the CER, which include the projected STCs required and small-scale technology percentage (STP). The implied electricity consumed is estimated by dividing the projected STCs by the relevant STP.

In its submission, Origin Energy noted:

> The forward price curve for LGC's is in decline reflecting the anticipated delivery of enough large-scale renewable generation to meet the peak Renewable Energy Target in 2020 and no planned extension of the scheme. The QCA should carefully consider whether its current approach of using the market price will adequately compensate retailers for their prudent LGC costs over the remaining years of the scheme …

[72] The NEM management fees were formerly referred to as the NEM participation fees.
[73] Section 40, *Renewable Energy (Electricity) Act 2000* (Cth).

> Origin acknowledges that the QCA has previously not adjusted its methodology when energy market prices are either higher or lower than long run costs. However, the decline in LGC prices is a consequence of policy/regulatory mechanisms rather than market conditions.[74]

Energy Queensland noted:

> Ergon Energy Retail, like many other retailers, has entered into long-term power purchase agreements with new renewable energy projects. This enables these projects to be developed while also enabling Ergon Energy Retail to meet its obligations under the Renewable Energy Target. For Ergon Energy Retail these will take full effect in the 2019-20 financial year. This constitutes a regulatory-driven change in how retailers purchase energy.[75]

ACIL Allen is maintaining the view that LGC spot and forward prices represent the most reliable indicator of the current market consensus view of the price of LGCs. A key reason for ACIL Allen's conclusion is the presence of LGC spot and forward markets that are sufficiently traded. A more detailed response by ACIL Allen is in chapter 3 of its draft report.

In its draft report, ACIL Allen estimated LRET costs using an approach broadly consistent with the previous determination. To improve the accuracy of the RPP estimates, ACIL Allen has updated the CER's published STPs and projected STCs required, given the recent observed strong uptake of small-scale energy systems. This approach could potentially reduce the variation in the LRET cost estimates between the draft and final determinations when the CER updates the SRES data in March 2019.

ACIL Allen has provided a detailed explanation of its calculations in chapter 4 of its report, along with information on LGC forward prices and the assumptions underpinning the implied RPP used.

ACIL Allen advised that LGC forward prices have fallen since they were last estimated for the 2018–19 final determination. This is primarily due to:

- a number of renewable energy projects reaching financial close in recent months, with most of these projects expected to be commissioned during 2019
- the mix of near-term renewable energy projects having a higher proportion of solar projects than wind, with solar projects having a shorter lead time to commissioning.

ACIL Allen advised that the significantly lower average LGC forward prices for 2020 reflect the market view that the LRET scheme is highly likely to be fully subscribed by 2020.

Using the expected average LGC prices and implied RPP for 2019 and 2020, ACIL Allen estimated that the LRET cost for 2019–20 would be $9.83/MWh for all retail tariffs—a reduction of $3.89/MWh compared to the 2018–19 final determination.

Comparison with the AEMC price trends report

In December 2018, the AEMC, with the assistance of EY, released a report on residential electricity price trends.[76] In this report, it is suggested that LRET costs for south east Queensland will decline to $7.20/MWh in 2019–20. This value is noticeably lower than ACIL Allen's estimate, which it arrived at by using a market-based approach.

EY has employed different methodologies to estimate the cost of LGCs for large and small retailers. For large retailers, EY estimated LGC prices as the subsidy required for a new

[74] Origin Energy, sub. 8.
[75] Energy Queensland, sub. 5.
[76] AEMC, December 2018.

renewable generator entrant to enter a power purchase agreement to recover its fixed and variable costs over the commissioning period of the plant till the end of the LRET scheme in 2030.

Estimating the cost of LGCs by using such an approach is highly dependent on the projected wholesale energy prices up until 2030. This is because this approach assumes that greater revenue from higher wholesale prices will reduce the LGC subsidy required for the new renewable generator entrant and vice versa.

To estimate the cost of LGCs for small retailers, EY appears to have used market prices for LGCs as at 8 August 2018, provided by a trading platform known as Mercari. In other words, EY used a point-in-time estimate to derive the LGC prices for small retailers.

ACIL Allen's methodology does not distinguish between small and large retailers in estimating the LRET costs. To estimate the expected LGC prices, ACIL Allen used the average of LGC forward prices (provided by TFS) traded over a two-year period leading up to 2019–20. This approach assumes that retailers build up their LGC portfolio over two years to meet their obligations under the LRET scheme.

ACIL Allen acknowledged that the LGC spot and forward markets may not be as deeply traded as the wholesale electricity forward market. However, it noted that the LGC forward market is an active market comprised of several brokers and trading platforms and as such provides a sound basis for estimating the value of LGCs. In fact, the existence of multiple brokers and trading platforms, coupled with an increase in recently committed new wind and solar farm developments trading on a merchant basis (rather than being covered by a power purchase agreement), suggests that the LGC forward market is sufficiently traded. LGC forward pricing is likely to be the most reliable indicator of the current market consensus view of the cost of LGCs that retailers will face to meet their obligations under the LRET scheme.

Therefore, we consider that ACIL Allen's market-based approach of using LGC forward pricing is likely to produce the most reliable estimate of LRET costs to be incurred by retailers in 2019–20.

QCA position

The QCA considers that ACIL Allen's market-based approach, using LGC forward price information provided by TFS and updated SRES data, is likely to produce the most reliable estimate of LRET costs to be incurred by retailers in 2019–20. The QCA notes that maintaining an approach for 2019–20 that is consistent with the approach used in previous determinations will also provide certainty to stakeholders.

The QCA’s draft decision is to accept ACIL Allen's advice on this matter and its LRET cost estimates (Tables 8 and 9).

SRES costs

The SRES provides an incentive for individuals and small businesses to install eligible small-scale renewable energy systems—such as solar panel systems, small-scale wind systems, small-scale hydro systems, solar hot water systems and heat pumps. Customers installing these systems create STCs, which retailers must purchase and surrender to the CER.

For its advice on the 2018–19 price determination, ACIL Allen estimated SRES costs by multiplying the expected STC price and the calendar-year STP published by the CER. The SRES cost for the financial year was derived by averaging the two calendar-year estimates. The expected STC price was based on the clearing house price.[77] The calendar-year STPs were based on the relevant final and non-binding STPs published by the CER.

In its submission on the ICP, Origin Energy noted that:

> the most recent update from the CER in December 2018 indicates a significant surplus of STCs created in Cal 2018 estimated at around 6-8 million STCs, this represents a variance of over 20 per cent above the published STP. This surplus will need to be added to the STP for 2019, which will be relevant to this determination. As the final binding STP for 2019 will not be published until March 2019, we suggest the QCA consults with the CER to obtain an up to date estimate for inclusion in the QCA's draft determination.
>
> Further, as the Cal 2020 STP is also relevant to this determination, we suggest that the QCA also consider revising upward the estimation provided by the CER's current non-binding STP. We would be happy to discuss our view of the Cal 2020 STP based on our expectations of the rate of installation. We note that various State incentives have increased installation rates, and that further policy announcements may further accelerate activity.[78]

In its draft report, ACIL Allen estimated SRES costs using a similar approach as in 2018–19. To address the issues raised by Origin Energy and improve the accuracy of the STP estimates, ACIL Allen has updated the CER's published STPs by considering the recent observed strong uptake in small-scale energy systems—using data up to 30 November 2018. This approach could potentially reduce the variation in the SRES cost estimates between the draft and final determinations when the CER updates the STPs in March 2019.

ACIL Allen estimated that the SRES cost for 2019–20 would be $6.49/MWh for all retail tariffs—an increase of $0.65/MWh compared to the 2018–19 final determination. This increase reflects a higher projected uptake of rooftop solar photovoltaic in 2019 and 2020.

QCA position

The QCA considers that ACIL Allen's approach is likely to produce the most reliable estimate of SRES costs to be incurred by retailers in 2019–20. The QCA also notes that maintaining a consistent approach for 2019–20 will also provide certainty to stakeholders.

Therefore, the QCA's draft decision is to accept ACIL Allen's advice on this matter and its SRES cost estimates (outlined in Tables 8 and 9).

4.2.2 NEM management fees and ancillary services charges

Retailers purchasing electricity from the NEM are required to pay NEM management fees and ancillary services charges to the Australian Energy Market Operator (AEMO). NEM management fees are levied by AEMO to cover the costs related to:

- operating the NEM
- performing its function as the National Transmission Planner
- full retail contestability
- funding Energy Consumers Australia.

Ancillary services charges cover the costs of services used by AEMO to manage power system safety, security and reliability.

[77] The STC clearing house is operated by the CER, and the clearing house price is fixed at $40 per STC (or per MWh of electricity generated by eligible systems).
[78] Origin Energy, sub. 8.

For its advice on the 2018–19 price determination, ACIL Allen used AEMO's budget and fee projections to estimate the NEM management fees. Ancillary services charges were estimated by using the average ancillary service payments[79] observed over the preceding 52 weeks.

In its draft report, ACIL Allen estimated the NEM management fees and ancillary services charges using the same methodology as in 2018–19. It estimated the NEM management fees using the projected fees in AEMO's *Final Budget and Fees 2018–19* report.[80]

ACIL Allen estimated that for 2019–20, NEM management fees would be $0.63/MWh, an increase of $0.10/MWh, compared to the 2018–19 final determination. This increase primarily reflects the higher costs that AEMO expects to incur when managing the NEM.[81] ACIL Allen estimated that ancillary services costs would be $0.37/MWh for 2019–20.

QCA position

The QCA considers that ACIL Allen's approach is likely to produce the most reliable estimate of NEM management and ancillary services costs to be incurred by retailers in 2019–20. The QCA notes that maintaining an approach for 2019–20 that is consistent with the approach in previous years will also provide certainty to stakeholders.

The QCA's draft decision is to accept ACIL Allen's advice on this matter and its cost estimates (Tables 8 and 9).

4.2.3 Prudential capital costs

Prudential capital costs are the costs that a retailer incurs to provide financial guarantees to AEMO and to lodge initial margins with the ASX in order to trade in futures contracts. These costs must be accounted for, as futures contracts are relied upon to derive the wholesale energy costs estimates.

For the 2018–19 price determination, ACIL Allen estimated prudential capital costs in line with the latest published AEMO requirements and margin requirements for trading in the ASX futures market. Prudential costs for customers settled on the Energex NSLP were estimated using the consumption profile of the Energex NSLP. These costs were also used as a proxy for the prudential costs of customers settled on the Energex CLPs. Conversely, prudential costs for customers settled on the Ergon NSLP were estimated using the consumption profile of the Ergon NSLP.

Energy Queensland[82] supported the use of the Ergon NSLP, instead of the Energex NSLP, to estimate prudential costs for large customers in regional Queensland.

Note that, to be consistent with the UTP[83], we need to use the energy cost estimates of:

- the Energex NSLP for residential, small business and unmetered supply (excluding street lighting) customers
- the Ergon NSLP for large business and street lighting customers.

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[79] AEMO provides data on weekly settlements for ancillary service payments in each interconnected region within the NEM.
[80] ACIL Allen, February 2019, chapter 4.
[81] AEMO noted that increased complexities in managing the grid and the changing nature of generation meant that further investment will be required to manage the NEM. See AEMO, June 2018.
[82] Energy Queensland, sub. 5.
[83] See Chapters 1 and 2.

In its draft report, ACIL Allen estimated prudential costs using an approach that is consistent with its 2018–19 approach.[84]

Prudential costs have fallen since the 2018–19 final determination, largely driven by lower expected price volatility in the NEM. ACIL Allen estimated that prudential costs for the Energex and Ergon NSLPs for 2019–20 would be $2.18/MWh and $1.52/MWh respectively.

QCA position

The QCA considers that ACIL Allen's approach is likely to produce the most reliable estimate of prudential capital costs to be incurred by retailers in 2019–20. Therefore, the QCA's draft decision is to accept ACIL Allen's advice on this matter and its prudential capital cost estimates (Tables 8 and 9).

4.2.4 Summary of other energy costs for 2018–19

Tables 8 and 9 set out the draft estimates of other energy costs for 2019–20, which will form part of the total energy cost allowances for retail tariffs.

Table 8 Other energy costs (excluding losses)—Energex NSLP and CLPs

Cost component	***$/MWh***	***Change from 2018–19***	
		%	***$/MWh***
LRET	$9.83	–28.4%	–$3.89
SRES	$6.49	11.1%	$0.65
NEM fees	$0.63	18.9%	$0.10
Ancillary services	$0.37	–14.0%	–$0.06
Prudential capital	$2.18	–26.1%	–$0.77
Total	**$19.50**	**–16.9%**	**–$3.97**

Note: Totals may not add due to rounding.

Source: ACIL Allen, February 2019.

Table 9 Other energy costs (excluding losses)—Ergon NSLP

Cost component	***$/MWh***	***Change from 2018–19***	
		%	***$/MWh***
LRET	$9.83	–28.4%	–$3.89
SRES	$6.49	11.1%	$0.65
NEM fees	$0.63	18.9%	$0.10
Ancillary services	$0.37	–14.0%	–$0.06
Prudential capital	$1.52	–27.3%	–$0.57
Total	**$18.84**	**–16.7%**	**–$3.77**

Note: Totals may not add due to rounding.

Source: ACIL Allen, February 2019.

[84] ACIL Allen, February 2019, chapter 4.

4.3 Energy losses

Some electricity is lost when it is transported over transmission and distribution networks to customers. As a result, retailers must purchase additional electricity to allow for these losses when supplying customers.

Consistent with its approach in 2018–19, ACIL Allen has accounted for energy losses by applying the transmission and distribution loss factors published by AEMO in a manner that aligns with AEMO's settlement process. These losses are based on AEMO's 2018–19 published loss factors, as loss factors for 2019–20 have not yet been published.

QCA position

The QCA’s draft decision is to accept ACIL Allen's advice on this matter and its loss factor calculations (Table 10). We expect ACIL Allen will update the loss factors using AEMO's 2019–20 loss factors in its final report.

4.4 Draft total energy cost allowances for 2019–20

Table 10 summarises the QCA’s draft decision on energy cost allowances for each retail tariff for 2019–20. To be consistent with the UTP[85], we propose to use the cost estimates of:

- the Energex NSLP and CLPs for residential, small business and unmetered supply (excluding street lighting) customers
- the Ergon NSLP for large business and street lighting customers.

Table 10 Total energy cost allowances for 2019–20, draft decision

Settlement class	*Retail tariff*	*Wholesale energy costs*	*Other energy costs*	*Energy losses (loss factor)*	*Total energy cost allowance*		*Change from 2018–19*
		$/MWh			*$/MWh*	*c/kWh*	*%*
Energex NSLP and unmetered supply	11, 12A, 14, 15, 20, 22A, 24, 41, 91	$89.08	$19.50	1.062	$115.31	11.531	–11.42%
Energex CLP 9000	31	$64.89	$19.50	1.062	$89.62	8.962	–0.40%
Energex CLP 9100	33	$72.49	$19.50	1.062	$97.69	9.769	–9.93%
Ergon Energy NSLP—SAC demand and street lighting	44, 45, 46, 50, 71	$75.39	$18.84	1.045	$98.47	9.847	–15.44%
Ergon Energy NSLP, high voltage—CAC and ICC	51A, 51B, 51C, 51D, 52A, 52B, 52C, 53	$75.39	$18.84	0.996	$93.85	9.385	–15.46%

Note: Totals may not add due to rounding.

Source: ACIL Allen, February 2019.

[85] See Chapters 1 and 2.

5 RETAIL COSTS

The second element of the R component, after energy costs, is retail costs, which include all retail operating costs, and a retail margin. The QCA has adjusted fixed retail cost allowances by forecast CPI, and has maintained variable retail cost allocators. Metering services costs for large customers have been updated based on the latest information from retailers.

5.1 Retail cost allowance

The retail cost allowance includes costs associated with a retailer providing customer retail services to its customers (called retail operating costs, or ROC) and the return to investors for exposure to systematic risks associated with providing these services (margin).

For our 2018–19 price determination, we maintained the fixed retail cost allowances established in our 2016–17 final price determination in real terms, and maintained variable retail cost percentage allocators as the same proportion of other variable costs established in the 2016–17 final price determination.[86] Our 2016–17 determination incorporated a thorough review of retail costs, which produced robust estimates that can be updated annually, using an escalation method.

Submissions

Kalamia Cane Growers Organisation (Kalamia) supported the QCA establishing new retail cost allowances based on up-to-date data, taking into account market contracts currently on offer in south east Queensland. Canegrowers expressed concern that the retail cost allowances established in the 2016–17 final determination significantly overstated retail costs.

Energy Queensland and the Queensland Consumers' Association supported benchmarks being updated, but acknowledged that this may not be possible due to time constraints. Energy Queensland highlighted that a number of factors, such as regulatory compliance changes and government policy changes, led to uncertainty around factors driving retail costs. Both Energy Queensland and the Queensland Consumers' Association supported using existing allowances as an alternative to updating benchmarks. Origin Energy also highlighted uncertainty generated by major government policy changes, and considered that it would be appropriate to use the existing allowances adjusted for the consumer price index to provide certainty to stakeholders.

QCA position

Given the uncertain policy environment at present, we agree with Energy Queensland, Origin Energy and the Queensland Consumers' Association that the retail cost allowances established in 2018–19 are an appropriate starting point for establishing the 2019–20 retail cost allowances. The QCA's draft decision is to adjust fixed retail cost allowances by forecast CPI, and to maintain variable retail cost percentage allocators as the same proportion of other variable costs used in the 2018–19 final price determination.

This is consistent with our previous approaches to setting retail prices, as well as with the UTP.

[86] More information on retail cost allowances can be found in our 2016–17 final price determination and ACIL Allen's associated reports, which are available on our website.

Residential and small business customers

For residential and small business customers, we propose to maintain retail cost allowances in real terms by:

- adjusting the fixed retail cost allowances (that were estimated for 2017–18) by the Reserve Bank of Australia's forecast of the change in the CPI for 2019–20[87]—to maintain them in real terms
- maintaining the variable retail cost percentage allocators at 11.27 per cent for residential customers and 12.8 per cent for small business customers—the same proportions of other variable costs first established in the 2016–17 final price determination.

Tables 11 to 13 set out our draft decision on retail cost allowances for regulated small customer tariffs in 2019–20.

Table 11 Retail costs for residential customers for 2019–20 (GST exclusive)

Retail tariff	*Pricing component*				
	Fixed retail component (c/day)	*Usage (c/kWh)*		*Demand ($/kW/mth)*	
		Peak	*Off-peak/flat*	*Peak*	*Off-peak/flat*
T11	37.488		2.287		
T12A	37.488	5.968	1.878		
T14	37.488		1.498	5.951	0.855
T31			1.734		
T33			1.860		

Table 12 Retail costs for small business customers for 2019–20 (GST exclusive)

Retail tariff	*Pricing component*				
	Fixed retail component (c/day)	*Usage (c/kWh)*		*Demand ($/kW/mth)*	
		Peak	*Off-peak/flat*	*Peak*	*Off-peak/flat*
T20	53.108		2.585		
T22A	53.108	6.438	2.420		
T24	53.108		1.770	8.791	0.883
T41	53.108		1.578		2.426
T91			2.325		

[87] We adopted a CPI of 2.125 per cent, equal to the average of forecast inflation at June 2019 and June 2020. See Reserve Bank of Australia, *Statement on Monetary Policy*, November 2018, table 5.1, p. 64.

Table 13 Retail costs for residential tariff 15 customers for 2018–19 (GST exclusive)

Retail tariff	*Fixed charge (Band 1) $/mth*	*Fixed charge (Band 2) $/mth*	*Fixed charge (Band 3) $/mth*	*Fixed charge (Band 4) $/mth*	*Fixed charge (Band 5) $/mth*	*Usage charge c/kWh*	*Summer peak top-up charge $/kWh/mth*
T15	11.410	11.410	11.410	11.410	11.410	1.487	0.930

Large business customers

Tables 14 and 15 show the QCA's draft determination on large business customer retail cost allowances. Consistent with the 2018–19 price determination, we have adjusted fixed retail cost allowances for large and very large business customers by forecast CPI[88], and maintained variable retail cost allocators at 6.0445 per cent.

Table 14 Retail costs for large business and street lighting customers

Retail tariff	*Pricing component*				
	Fixed (c/day)	*Usage (c/kWh)*		*Demand ($/kW/month)*	
		Peak	*Off-peak/flat*	*Peak*	*Off-peak/flat*
T44	379.813		0.674		1.971
T45	1044.466		0.674		1.458
T46	2656.861		0.673		1.194
T50	342.059	0.654	0.789	3.630	0.632
T71			1.543		

Table 15 Retail costs for very large business customers

Retail tariff	*Pricing component*						
	Fixed (c/day)	*Usage (c/kWh)*		*Connection unit ($/day/unit)*	*Capacity (flat/off-peak) ($/kVA of AD/mth)*	*Demand (flat/peak) ($/kVA/mth)*	*Excess reactive power ($/excess kVAr/mth)*
		Peak	*Off-peak/ flat*				
T51A	2630.004		0.649	0.561	0.246	0.149	0.242
T51B	2630.004		0.649	0.561	0.303	0.153	0.242
T51C	2630.004		0.649	0.561	0.352	0.186	0.242
T51D	2630.004		0.650	0.561	0.690	0.375	0.242
T52A	2630.004	0.623	0.645	0.561	0.377	0.665	0.242
T52B	2630.004	0.623	0.645	0.561	0.265	2.505	0.242
T52C	2630.004	0.624	0.646	0.561	0.489	4.372	0.242
T53	2448.262		0.650		0.690	0.375	0.242

[88] We adopted a CPI of 2.125 per cent, equal to the average of forecast inflation at June 2019 and June 2020. See Reserve Bank of Australia, *Statement on Monetary Policy*, November 2018, table 5.1, p. 64.

Metering charges

Consistent with the approach taken in the 2018–19 determination, the QCA has based metering costs for large customers on confidential metering cost data provided by retailers. Our draft determination on metering fees is in Table 16.

The QCA averaged the data provided to produce cost estimates for each large customer type. In contrast to 2018–19, the latest data showed that costs for standard asset customers were lower for customers with consumption under 750 MWh per annum.

Overall data from retailers showed decreases for standard asset customers and individually calculated customers, and increases in metering costs for standard asset customer (large) and connection asset customers.

Table 16 Metering charges for large and very large business customers

Customer type	***Metering charge (c/day)***
Standard asset customer	160.761
Standard asset customer (large)	202.308
Connection asset customer	430.801
Individually calculated customer	434.813

Source: Retailer data.

6 OTHER ISSUES

There are other matters which need to be considered in determining notified prices, including adjustments impacting the level of notified prices in 2019–20.

Having considered each of these other issues, the QCA's draft decision has focussed on consistency and certainty in treatment of matters where this is appropriate. In addition, the QCA's draft decision has ensured cost pass-throughs are appropriate and transparent, identifying relevant costs from 2018–19 which will be reconciled in, and form part of, the overall level of notified prices in 2019–20.

The chapter provides an overview of each of the issues, including factors relevant to the QCA's consideration, and sets out the QCA's draft decision on each matter.

6.1 Standing offer adjustment—residential and small business customer tariffs

6.1.1 Considerations for this review

Chapter 1 discusses key considerations for the QCA in determining the notified prices, including relevant legislative factors (section 1.3) and matters we are required to consider by the Minister's delegation (section 1.4).

Broad factors the QCA must have regard to, as set out in the delegation, are similar to previous electricity price determinations the QCA has undertaken. For instance, the Minister identified that the government's UTP remains an important consideration when determining electricity prices for regional customers. Similarly, the Minister said promoting greater levels of retail competition also remains an important consideration.

Specific matters the QCA must have regard to, also set out in the delegation, are different to matters we were required to consider in previous determinations. For instance, the Minister identified some factors relevant to the QCA's consideration of the standing offer adjustment, as set out in the delegation and covering letter (see Appendix A).

The possible inclusion of an adjustment in notified prices is set out explicitly in the terms of reference in the delegation, requiring the QCA to consider:

> incorporating into notified prices, an appropriate value reflecting the more favourable terms and conditions of standard retail contracts compared to market contracts.[89]

The Minister's cover letter provides additional guidance, including factors the QCA should consider when determining the basis for, and level of, the adjustment to incorporate within notified prices. In summary, these relate to:

- the basis of the adjustment:
  - given the increasing divergence between standing offer prices and market offer prices in south east Queensland, it is no longer appropriate to use these factors as reference points for determining the basis on which the adjustment should be made

[89] 5(b) of the Terms of Reference, Minister's Delegation (Appendix A).

  - instead, it is preferable to use the additional protections contained in standard contract terms and conditions as the basis for determining an adjustment, ensuring notified prices account for the additional value of these protections

- the value of the adjustment—the level of the adjustment made by the QCA in previous determinations appropriately reflects the additional value afforded via protections contained in standard contract terms and conditions.

On the latter point, the Minister also considered an adjustment level similar to previous determinations would reflect the intent of the government's UTP.

6.1.2 Stakeholder comments

Stakeholders' comments on various elements of the standing offer adjustment were mixed.

Some stakeholders considered an adjustment should not be made[90], whereas others said incorporating an adjustment would be consistent with previous determinations and should be maintained.[91]

Stakeholders' comments on the basis of the adjustment were varied:

- Energy Queensland supported the approach outlined in the delegation and said it was not aware of a more appropriate alternative approach to estimating the standing offer adjustment.[92]
- The Queensland Consumers' Association said a review is needed and questioned the appropriateness of linking regional prices to standing offer prices in south east Queensland given: the increased diversity of types of market offers in south east Queensland; the declining proportion of consumers on standing offers; and the fact retailers have an incentive to set the highest possible standing offer prices in order to advertise high discounts. It also questioned the validity of the assumption made by the delegation that the standard contract provides significant additional protections and, therefore, value to consumers.[93]
- QCOSS questioned whether there was any basis for making an adjustment based on the value of standard terms and conditions. It referred to reports that had found customer protections (such as access to paper billing, payment periods and other terms) do not justify a higher price, especially if loyal and disengaged customers are staying on the higher standard contracts. Also, many market contracts now contain terms similar to standing offers (such as not having exit fees, and many do not have late payment fees).[94]
- A number of stakeholders raised the AER's review of the default market offer (DMO) and whether this review could have implications for the QCA's process, retail prices and the operation of retail markets.[95] Energy Queensland did not consider there were direct implications for the QCA's price-setting process and said the QCA's approach should be

[90] Canegrowers Isis, sub. 3, p. 2.
[91] Origin Energy, sub. 8, p. 3.
[92] Energy Queensland, sub. 5, p. 10.
[93] Queensland Consumers' Association, sub. 11, p. 2.
[94] QCOSS, sub. 10, p. 2.
[95] Origin Energy, sub. 8, p. 1; Queensland Consumers' Association, sub. 11, p. 2; QCOSS, sub. 10, p. 3.

maintained.[96] Other stakeholders said there were risks, and the AER's process creates uncertainties that may have implications for the QCA's process.[97]

Stakeholders generally agreed the level of the adjustment should be either the same, or less than, that applied in previous years:

- Canegrowers Isis said if an adjustment is applied, it should not be more than 5 per cent. This ensures the adjustment is restricted to a commercially competitive range and regional areas are not disadvantaged in comparison to south east Queensland urban customers.[98]
- The Queensland Consumers' Association said the adjustment should not be greater than the 5 per cent previously applied, but should be considerably lower. It questioned whether standard contracts provide significant additional protections and, therefore, value to consumers.[99]
- Origin Energy supported maintaining the standing offer adjustment at 5 per cent.[100]
- Energy Queensland supported retaining the standing offer adjustment at 5 per cent and considered this was consistent with the UTP.[101]

6.1.3 QCA analysis and draft decision

The QCA's consideration of the standing offer adjustment is discussed as follows:

The QCA notes stakeholders' comments in relation to the AER's review on the DMO. While matters concerning the DMO have been raised in the context of the standing offer adjustment, we have addressed these in a separate section (see section 6.2).

Rationale for an adjustment

The QCA has been delegated the task of determining notified prices for customers in regional Queensland.[102]

Under the Electricity Act, notified prices need to reflect the price a retailer may charge its 'standard contract customers'[103] and, consistent with the government's UTP, this means the expected level of standing offer contract prices a retailer may charge in south east Queensland.

In this price determination, we have been directed to consider including an adjustment in notified prices to reflect the additional value customers obtain from the terms and conditions contained in standard contracts.[104]

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[96] Energy Queensland, sub. 5, pp. 12–13.
[97] Origin Energy, sub. 8, p. 1, Queensland Consumers' Association, sub. 11, p. 2, QCOSS, sub. 10, p. 3.
[98] Canegrowers Isis, sub. 3, p. 2.
[99] Queensland Consumers' Association, sub. 11, p. 3.
[100] Origin Energy, sub. 8, p. 2.
[101] Energy Queensland, sub. 5, p. 10.
[102] Customers in Queensland other than those in the Energex distribution area—e.g. outside of the south east Queensland region.
[103] The task does not involve determining the least-cost supply or lowest market offer, and requires additional consideration. Standard contract terms and conditions are set by the National Energy Retail Rules (NERR). See NERR, rule 12, Schedule 1.

For these reasons, the QCA considers it is necessary and reasonable to incorporate an adjustment. This ensures the QCA's notified prices, taken as a whole, with each component used to build up the notified prices, reflect these requirements.

The basis of the adjustment, including factors relevant for 2019–20

Having accepted it is necessary to incorporate an adjustment into notified prices, the QCA has then considered the basis on which the adjustment should be made.

A number of different options are available when considering the basis on which the adjustment could be made. It is also evident that, over time, new information or considerations may arise and which may suggest an alternative method is more appropriate.

For the 2019–20 review, the QCA has been directed to consider basing the adjustment on the 'value' of standard contract terms and conditions. This is intended to reflect the additional protections customers are afforded by contracting on standard terms and conditions (set out in the National Energy Retail Rules).

This approach involves an assessment of the value of non-price factors (whereas the previous approach involved an assessment of the standing offer contract prices and market contract prices and, to the extent there was a difference, this was reflective of both price and non-price factors).

As a result, the revised approach appears to address some of the key concerns raised by the Queensland Consumers' Association and QCOSS. By no longer focusing on price factors, the approach may resolve key concerns raised by stakeholders. For instance, it removes issues around linking the adjustment to standing offer prices, the potential for retailer prices to be inflated and the difficulties with reconciling the divergence between standing offer prices and market offer prices on the basis of non-price contract terms alone.

Even so, undertaking a quantitative assessment remains a difficult and complex task. Retail prices (for standard or market contracts) are not presented by retailers as a component-based cost build-up that adds to the final offer price. Therefore, while the new approach constrains the matters which may be considered as part of estimating the value, the data and other information used in the assessments remain the same and do not allow for the level of transparency and reconciliation of the adjustment value that stakeholders may desire.

Similarly, the qualitative aspect of the assessment is likely to require a degree of judgement and pragmatism. Determining what 'value' customers place on having standard terms and conditions is highly subjective and likely to be an area where stakeholder views differ markedly (also, views may change over time and depend on individual customer circumstances). This is evident based on the stakeholder comments received on this matter.

While such terms may not be considered of value to some stakeholders, the QCA nonetheless considers the simplicity, balance and ongoing availability of these terms are relevant factors to consider. Standard contract terms, typically viewed as benefits and/or protections, relate to simple pricing, access to bills at no extra cost, better payment terms (which can include bill smoothing) and ongoing certainty of terms (retailers cannot change terms or impose restrictions, as they can under market contracts).[105]

[104] Delegation and cover letter (Appendix A), Executive summary and chapter 2.
[105] ACCC, June 2018, p. 248.

These features of standard contract terms provide a level of stability, certainty and consistency for customers who might otherwise be subject to changing terms, including the imposition of restrictions or requirements to meet stricter terms (with financial penalties for non-compliance).

Accordingly, the QCA is satisfied that incorporating an adjustment into notified prices is reasonable and that, for reasons discussed above, using non-price terms forms a reasonable basis on which to make such an adjustment.

The QCA invites stakeholders to provide suggestions on alternative options if the concerns initially raised have not been fully addressed, including how the QCA may consider assessing the basis (empirically or otherwise) of any alternative approaches suggested.

An appropriate value

In the previous section, the QCA discussed the difficulties that may arise in determining an appropriate value for the adjustment, given the nature of the information available and the extent to which both quantitative and qualitative aspects are able to be measured.

As such, the QCA has decided to assess this matter on the basis of all relevant information available, including market data and observations, our directions under the delegation, stakeholder views and other information.

This approach ensures a balanced consideration, as it incorporates:

- data and market observations, where possible and appropriate
- other information to inform the assessment more broadly, where necessary—including taking into account stakeholder and government views, implications for the adjustment and other relevant factors.

Market data, observations and impacts

The QCA has considered data and market observations gathered in performing previous price determinations and in the south east Queensland market monitoring reports it regularly prepares and publishes on its website.

Price determination 2018–19

In the 2018–19 price determination, the QCA observed there was a price differential (between market offer retail prices and standing offer retail prices) of around 13.5 per cent, but noted:

- the value reflects both price and non-price factors
- there was no evidence to allow the components of this differential to be identified and broken down further.

In addition, the QCA noted that while the market offers are generally priced at a discount to retailer standing offers in south east Queensland, it was apparent the increasing price differential observed over recent years potentially reflects not only the more favourable terms and conditions in standard contracts, but also a range of other factors (e.g. retailer loyalty, customer inelasticity and marketing strategies).

The QCA considers this information informs the assessment and supports a value significantly less than the 13.5 per cent price differential as being appropriate to reflect the non-price factors alone.

If a value close to the upper limit was applied, this would shift the burden of the adjustment more heavily to customers (via higher notified prices).

SEQ market monitoring report, November 2018

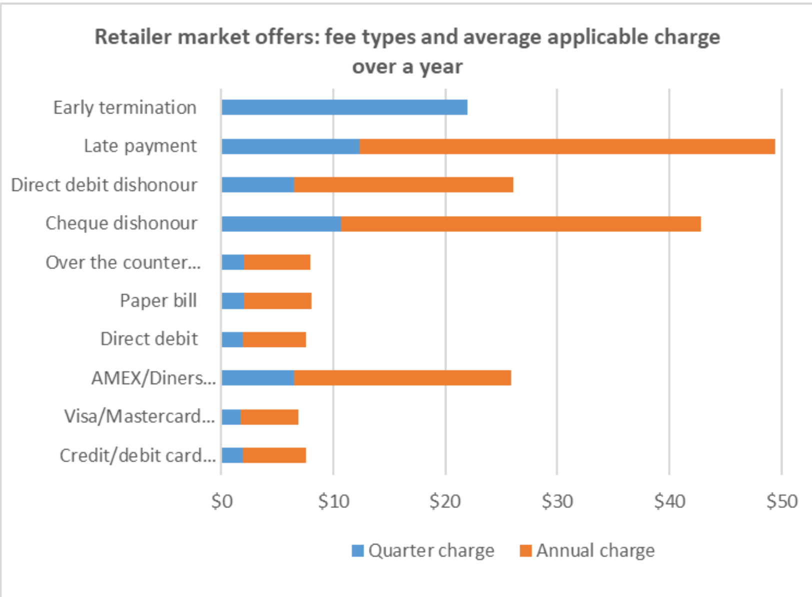
In November 2018, the QCA observed the range of additional fees and charges in retail market offer contracts in south east Queensland. A summary of fees and charges in market offers for residential and small business customers is presented separately (Figure 15 and 16), noting the dollar values represent the average charge for a particular fee type, where that fee is applied by retailers.[106]

In presenting the data on fees and charges, the QCA notes that it has limitations (discussed below). Accordingly, developing a methodology to use the data for estimating a possible value would require careful and detailed consideration. Given these factors and the timing constraints of this project, we do not propose to rely on such an approach at this time to determine an appropriate value. Nonetheless, the discussion below highlights how one might consider approaching the problem.

The fees are presented (Figure 15 and 16) on the basis of a quarterly bill charge and on the basis of the annual bill (cumulative) charges.[107] For residential and small business customers, market offer fees and charges show that the largest potential, additional charges are incurred for late payments and cheque dishonour fees. For retailers that apply:

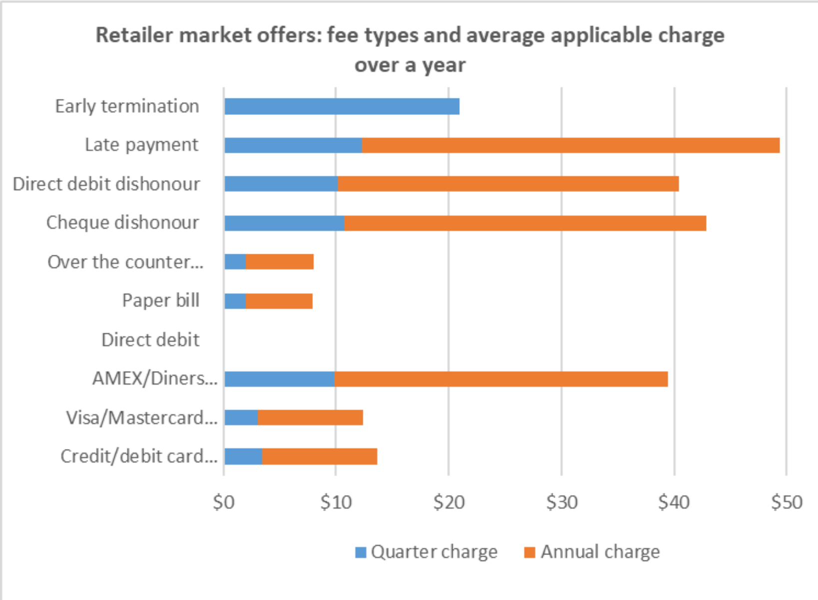
- a late payment fee—the maximum potential charge that a residential or small business customer could incur is, on average, around $12 per quarter, or $48 annually
- a cheque dishonour fee—the maximum potential charge that a residential or small business customer could incur is, on average, around $11 per quarter, or $44 annually.

Figure 15 Residential customer: summary of market offer fees and charges



[106] Where a retailer does not apply that particular fee type (e.g. there is a zero value for that fee type), that retailer is excluded from the sample. That is, the average dollar value calculations use only non-zero values to determine the average charge.
[107] QCA, November 2018, Table 50 and 51.

Figure 16 Small business customer: summary of market offer fees and charges



The QCA also observed the significant variability between the type, value and combination of fees and charges in retailer market offers and the variation in potential impacts on a customer's annual bill:

- For residential customers—the highest fees contained in a retail market offer that could be incurred by a customer were around $116 and represented 9.5 per cent of a median annual bill.[108]
- For small business customers—market offers showed the highest charges that could be incurred by a customer were around $164 and represented 7.4 per cent of a median annual bill.

The QCA considers this information suggests one possible range–costs 'avoided' may be up to 9.5 per cent for residential customers on standard contracts and up to 7.4 per cent for small business customers on standard contracts.

However, there are limitations inherent in this analysis. While it provides a useful indicator of the maximum level of charges a customer may incur under various market offer contracts (but which are 'avoided' by customers on standard contracts):

- The charges are subject to change (as retailer market offers change).
- The charges only take into account market offer fees that are published on the Energy Made Easy website (some retailers refer to the potential for retail fees—other than those listed on Energy Made Easy—to be levied on customers) .
- The variability between retailers (including by fee type and level) makes it difficult to determine which market offer fees and charges are likely to apply to particular customers, including the various combinations of types of fees and charges that may be incurred.

[108] Fees and charges for each retailer as presented in the QCA's November 2018 retail electricity market monitoring report (chapter 4). We have calculated the sum of all fees charged under each individual retailer market offer—this represents the maximum charges a customer could incur in a given year. The fees are then used to determine the percentage the charges represent compared to a median annual customer bill.

- It is difficult to determine what portion of the maximum fees and charges we have observed would be incurred—for example, there is no evidence on the level (or incidence) of actual charges a customer typically incurs (it is likely to be some portion of charges which would vary based on individual customer circumstances).

As a result, it is difficult to empirically determine a precise value, within the range of potentially acceptable values, that is an appropriate value for the standing offer adjustment on the basis of the data available and limitations identified. However, the QCA considers this information informs the range of potentially acceptable values and supports a value of 9.5 per cent or less as being appropriate to reflect the value of terms and conditions contained in standard contracts.

Other information

While difficult to quantify a specific value using empirical methods, the QCA is nonetheless satisfied there is a positive value associated with the terms and conditions contained in standard contracts, including due to the stability, certainty and consistency that standard contracts provide to customers (discussed above).

The QCA is also satisfied the value is likely to be less than the upper limit of the observed market offer and standard offer price differentials (which reflect price and non-price factors).

The QCA has been directed to consider adopting a value similar in magnitude to that applied in previous determinations, on the basis the Minister considers this appropriately reflects the additional value of the terms and conditions of standard retail contracts. The QCA notes a value of 5 per cent was adopted in previous determinations.

The QCA also considers the government's EasyPay Reward scheme could provide information useful to this assessment. The scheme offered customers an annual reward in the form of a bill credit for electing (and meeting) particular conditions different to those contained in the standard contracts—namely to receive bills electronically, pay on time, use a particular payment method and accept bill smoothing. The reward equated to a reduction in notified prices of around 5 to 6 per cent per year (average) for these customers, if all conditions were met.[109]

While stakeholders broadly supported an adjustment of 5 per cent, some stated a preference for it to be less, but did not provide detailed information on the level that should be adopted or the basis on which a lesser value was more appropriate. There was no stakeholder support for the adjustment to be higher.

The QCA considers the delegation, the government's EasyPay Reward scheme and stakeholder views provide some indication of a value that might be appropriate, including by providing broad qualitative guidance on the magnitude of the adjustment and value customers and government are expecting to be incorporated into notified prices in 2019–20.

If a value of around 5 per cent is applied, there would be no shift in impact and cost burden compared to previous determinations (e.g. the adjustment to notified prices in 2019–20 would be consistent with that applied previously).

Conclusion and QCA position

On the basis of all of the information available, the QCA considers it is reasonable to maintain a standing offer adjustment of 5 per cent to be incorporated into 2019–20 notified prices.

[109] Details of the EasyPay Reward scheme are set out in detail in the QCA's 2018–19 price determination. In particular, the annual bill credit applicable for meeting all conditions was $75 for residential customers and $120 for small business customers.

This approach is considered appropriate, as it ensures:

- data and market observations are used where possible and appropriate, including to guide the range of values which could be appropriate
- other information is used to inform the assessment more broadly where necessary, including stakeholder views and expectations, our directions and government expectations and the benefits (in terms of consistency and certainty) of maintaining a value consistent with that applied in previous price determinations.

This approach results in an adjustment that is generally supported by, and aligned with, stakeholder and government expectations. It is also consistent with the value adopted in previous determinations, ensuring the impact (cost burden) for customers and government is similar to that in previous determinations.

The QCA accepts this approach has taken into account broader factors and, to the extent empirical data is not available to justify using an alternative value, the QCA has relied on other information (including stakeholder and government views and expectations) to determine an appropriate value.

The QCA invites stakeholders to consider whether an alternative value might be more appropriate, including the information (empirical or otherwise) the QCA should consider in support of applying any alternative value.

6.2 Default market offer

In late 2018, the Commonwealth Government announced its intention to introduce a 'default market offer' (DMO) for residential and small business customers in each NEM network distribution region that does not have a regulated standing offer price (via state-based price regulation).

The AER has been directed to set a maximum DMO price for relevant network regions by 30 April 2019 (with prices to take effect from 1 July 2019).[110]

Our interim consultation paper discussed this matter in the context of our price determination process. We noted the AER's DMO would not apply in regional Queensland, given the notified prices we determine constitute a 'regulated standing offer price'. However, we asked stakeholders to provide comments on this matter if they considered any aspects warranted further consideration.

A number of stakeholders commented on this matter. While some raised concerns around the implications and potential impacts on the QCA's price determination, others did not consider there would be any direct implications given the different task and process:

- Energy Queensland did not consider there were direct implications for the QCA's price setting process and said the QCA's approach should be maintained. It said the tasks, methodology and approach differed markedly and served a different purpose—for instance, the QCA uses a 'bottom-up' analysis of efficient retail costs to determine notified prices, while the AER has proposed a 'top-down' approach based on current market and standing offer prices to determine DMO prices.[111]

[110] J Frydenberg (Treasurer, Australian Government) and A Taylor (Minister for Energy, Australian Government), letter to the AER, 22 October 2018, p. 1.
[111] Energy Queensland, sub. 5, p. 11.

- The Queensland Consumers' Association said if the DMO is implemented in south east Queensland, it could have major implications for the setting of regulated prices in regional Queensland.[112] However, it also noted many of the details around the DMO were uncertain (including timing) and therefore the QCA should continue to apply the approach used in previous price determinations for this review.[113]
- QCOSS said the AER process is different than the QCA's process and may produce different outcomes, but it will consult government and regulators and raise any concerns that become apparent.[114]
- Origin Energy said it expected the AER and ESC to take guidance from the QCA's work and, for this reason, it is important for the QCA to ensure its method and decision produces results that reflect the objective for a regulated tariff to support the development and maintenance of competition.[115]

QCA position

The QCA does not consider the AER's DMO process should have implications for this price determination. On the basis of all information available, it is evident that:

- The AER is intending to determine DMO prices for application in south east Queensland (not regional Queensland).
- The AER intends to determine default (or 'safety net') prices that in theory should be paid by only a small proportion of small customers in the south east Queensland market, where competition is relatively effective. By contrast, the QCA's task is to determine notified prices paid by most customers in regional Queensland in a market where competition is limited.
- As noted by Energy Queensland, the QCA's methodology and approach differ significantly from the AER's proposed methodology[116] for determining DMO prices.

As such, the QCA considers it likely the QCA and AER processes may produce different outcomes given the different tasks, methodology and approaches applied.

For the reasons discussed above, the QCA does not intend to have regard to the AER's DMO process in this price determination, but will continue to monitor how this matter progresses and may reconsider any potential implications at a later stage, if necessary.

6.3 Headroom for large and very large business customer tariffs

In determining the notified prices for large and very large business customers, the QCA must consider incorporating a headroom adjustment. This is intended to facilitate and encourage competition in the large customer market segment in regional Queensland and encourage customers to seek more attractive market offers.

[112] Queensland Consumers' Association, sub. 11, p. 2.
[113] Queensland Consumers' Association, sub. 11, p. 2.
[114] QCOSS, sub. 10, p. 2.
[115] Origin Energy, sub. 8, p. 1.
[116] See AER, November 2018, for a description of the AER's proposed methodology for determining DMO prices.

Considerations for this review

Chapter 1 discusses key considerations for the QCA in determining the notified prices, including relevant legislative factors (section 1.3) and matters we are required to consider by the Minister's delegation (section 1.4).

Broad factors the QCA must have regard to, as set out in the delegation, are similar to previous electricity price determinations the QCA has undertaken. For instance, the Minister identified that promoting greater levels of retail competition remains an important consideration in this review.

Specific matters the QCA has regard to when considering this matter are also similar to previous determinations the QCA has undertaken. For instance, the Electricity Act requires us to have regard to the effect of our price determination on competition in the Queensland retail electricity market.[117] The QCA notes the delegation does not direct us to consider specific factors related to incorporating a headroom adjustment into notified prices.

6.3.1 Stakeholder comments

Some stakeholders supported the continued application of the headroom component in notified prices on the basis of the competition benefits:

- Origin Energy supported applying the approach used in previous determinations, including continuance of an allowance added to efficient costs to support the development and maintenance of competition.[118]
- Energy Queensland supported competition for regional customers and the continued allocation of a headroom component in notified prices. It said this approach has developed a level of competition that is in part facilitated by the inclusion of headroom.[119]

Other stakeholders supported the development of competition, but considered the headroom component was arbitrary and should not be included in notified prices:

- Cotton Australia opposed the headroom charges. It said this is akin to a supermarket putting up prices so they can offer a sale (at the original price) the next day. Discounting should be funded through efficiencies and increased market share, not inflated regulated prices.[120]
- Canegrowers Isis submitted that headroom was a theoretical and arbitrary consideration, which is not reasonably applicable in the instance and scale of a public utility. It considered that the government should improve the efficiency of Ergon if it wished to reduce the subsidy it pays to uphold the UTP. [121]

6.3.2 QCA analysis and position

The QCA's draft determination is to incorporate a headroom adjustment of 5 per cent into notified prices in 2019–20. This approach is appropriate, as it:

- promotes greater levels of retail competition, including continuing to facilitate and encourage greater competition in the large customer market segment in regional Queensland

[117] s. 90(5) of the Electricity Act.
[118] Origin Energy, sub. 8, p. 3.
[119] Energy Queensland, sub. 5, section 6.2.
[120] Cotton Australia, sub. 2, p. 3.
[121] Canegrowers Isis, sub. 3, p. 3.

- encourages customers to engage in the market and seek out more attractive offers, which provides the ongoing benefit of stimulating market conditions now and into the future.

The QCA has considered alternative approaches but has decided these are not appropriate at this time. In the case of incorporating a headroom adjustment, the options would involve removing or reducing the adjustment made. Also some stakeholders suggested broader matters, including electricity company efficiency factors, which are outside of the scope of matters able to be reviewed in this process.

The QCA accepts it is difficult to assess the impact of including the headroom adjustment and the level of adjustment that would best facilitate retail competition. The very nature of including an adjustment that seeks to promote a particular outcome means the benefits, if achieved, are likely to be revealed gradually and over time, rather than as an immediate identifiable transformation in market conditions.

Also, the QCA accepts some barriers to the development of widespread competition likely remain:

- setting uniform notified prices—retailers cannot compete for customers in higher-cost areas of regional Queensland, where the actual cost of supply is greater than the regulated retail notified prices (e.g. individually calculated customers)
- the risk of switching—once large or very large customers accept a market contract, they are not allowed to return to Ergon Retail, which may discourage them from accepting a market offer.[122]

Even so, there has been an increase in the number of large and very large customers on market contracts in recent years, and a degree of effective competition has developed—particularly in areas where notified prices more closely reflect the actual cost of supply (Ergon Distribution east pricing zone, transmission region one). Some stakeholders say these market conditions have been assisted by the inclusion of a headroom adjustment in notified prices.

Separately, including headroom in regulated retail prices has been recommended in electricity pricing reviews, including as a means of facilitating competition and encouraging consumer participation in the market.[123]

On balance, the QCA considers including headroom in notified prices will encourage competition in the large customer market segment in regional Queensland (consistent with the government's aims) and provide stability and certainty to customers by adopting an approach consistent with that applied by the QCA in previous price determinations.

6.4 Cost pass-through mechanism

Cost pass-through mechanisms are used by regulators to mitigate the risk that the costs allowed for in regulated prices are higher or lower than the actual efficient costs of supply. Cost pass-through mechanisms are usually restricted to events that are outside the control of the regulated entity.

The existing framework for determining notified prices provides for cost pass-throughs to be taken into account in certain circumstances. Under these arrangements, under- or over-

[122] This restriction also applies to any future occupants of the premises (e.g. if the premises are sold or occupied by a new tenant).
[123] AEMC, September 2013.

recovery of certain costs may be required to ensure notified prices continue to remain aligned and consistent with the government's UTP.

Consistent with this framework, the QCA intends for the SRES costs to be subject to a cost pass-through mechanism. While SRES costs are incurred by retailers, the level of costs is determined using the final small-scale technology percentages (STPs) set by the Australian Clean Energy Regulator (CER), as discussed in detail in section 4.2.

This approach will ensure notified prices:

- are updated to account for the final STP applicable in 2019, which is published by the CER in March 2019
- incorporate any under- or over-recovered amounts relating to the SRES costs in 2018–19—that is, to account for differences in the forecast and actual SRES costs.

As a result, notified prices are reconciled between price determinations and maintain consistency with the government's UTP.

Stakeholders broadly supported this approach, provided any cost pass-throughs can be accurately identified.[124] Origin Energy expected that the 2018–19 pass-through and the final SRES amounts included in notified prices would be impacted by CER updates:

> [T]he rate of solar installation has exceeded that assumed in the published STP, retailers are likely to have under-recovered SRES costs for 2018-19…
>
> … the most recent update from the CER in December 2018 indicates a significant surplus of STCs created in Cal 2018… this surplus will need to be added to the STP for 2019, which will be relevant to this determination.[125]

Origin Energy suggested the QCA obtain updated estimates for inclusion in the draft determination, and consider revising (upward) the estimation provided by the CER's current non-binding STP for 2020.[126]

QCA position

The QCA considers the pass-through mechanism is appropriate to apply to SRES costs, with the mechanism to apply being consistent with the approach taken in previous determinations.

This approach is generally supported by stakeholders and ensures notified prices are calculated to maintain consistency with the UTP, including taking account of variances between forecast and actual SRES amounts included in the past price determinations (and notified prices).

The QCA has considered the matters raised by Origin Energy and addressed these in detail in Chapter 4.

6.5 Enabling additional retailer services and execution of government policy

The delegation requires us to consider incorporating government policy matters within notified prices to enable retailers to offer (and customers to participate in) relevant programs or schemes.

In particular, the delegation directs us to consider the additional services relating to the:

[124] Canegrowers Isis, sub. 3, p. 3; Origin Energy, sub. 8, p. 2; Energy Queensland, sub. 5, section 6.3.
[125] Origin Energy, sub. 8, p. 2.
[126] Origin Energy, sub. 8, p. 2.

- purchase of electricity from renewable or environmentally friendly sources[127]
- EasyPay Reward scheme, which entitles customers to rewards (payment credits) if they meet certain conditions (up until 30 June 2020).

No stakeholder feedback was received with regard to the additional customer retail service activities (and charges). Where stakeholders have feedback on how these schemes can be improved, the QCA encourages stakeholders to provide this feedback to government so that it can inform future policy decisions.

As such, there is no reason for the QCA to refuse to enable the changes proposed with regard to renewable or environmentally friendly retailer services. The programs do not affect customers' rights to standard contract terms and conditions or notified prices.

The QCA notes the available schemes will be incorporated into the Gazette notice once the QCA makes a final determination. No additional calculations or requirements are necessary to ensure retailers are able to provide these additional services (and customers can decide and elect to participate if they wish to do so).

6.6 Controlled load tariffs for the Essential Energy area

Origin Energy raised an issue regarding the application of controlled load tariffs for customers connected to the Essential Energy network. The QCA sets controlled load tariffs based on the network tariffs in the Energex distribution area. However, controlled load tariffs operate differently on the Essential Energy network, as they are available at different times to those associated with the Energex controlled load network tariffs. Table 17 shows the differences in timing between the two networks.

Table 17 Essential Energy controlled load intervals

Essential Energy tariff	***Current notified price retail tariff***
CL1 Electricity is supplied for five to nine hours overnight on weekdays, with possible extra hours on weekends (except where the load is controlled by a time clock).	Tariff 31 Power is available for a minimum of eight hours each day. The times when power is switched off may change from day to day and vary in duration.
CL2 Electricity is supplied for 10 to 18 hours overnight on weekdays and all hours on weekends (except where the load is controlled by a time clock).	Tariff 33 Power is available for a minimum of 18 hours each day. The times when power is switched off may change from day to day and vary in duration.

Source: Origin Energy, sub. 8..

While it may be possible to resolve this through changing network hardware, due to the small number of customers involved, it would likely be prohibitively expensive to do so. Origin Energy suggested that separate retail tariffs be created to reflect the different terms and conditions associated with the Essential Energy controlled load tariffs.

The QCA proposes to address this issue by amending the terms and conditions of the existing controlled load tariffs to note that customers supplied through the Essential Energy network will be supplied according to the timing associated with the Essential Energy network tariff.

While there will be an unavoidable difference in the timing of controlled load tariffs, customers will pay the same notified price per kWh. This will result in customers of the same class paying

[127] Whether or not those additional amounts are calculated on the basis of the customer's electricity usage.

the same notified price, which is based on Energex network costs. As a result, the QCA considers this solution complies with both the UTP and clause 5(d)(i) of the delegation.

The amended wording of the terms and conditions of the controlled load tariffs is contained in the draft Gazette notice at Appendix F.

7 TRANSITIONAL ARRANGEMENTS

The delegation requires that the QCA consider reclassifying transitional tariffs (tariffs 20 (large), 21, 22 (small and large), 62, 65 and 66) as obsolete tariffs.

The QCA's draft decision is to:

- *reclassify all transitional tariffs (tariffs 20 (large), 21, 22 (small and large), 62, 65, and 66) as obsolete, allowing existing customers to remain on these tariffs but closing them to new customers*
- *maintain existing transitional periods for tariffs 20 (large), 21, 22 (small and large), 37, 47, 48, 62, 65 and 66*
- *maintain transitional and obsolete tariffs at their 2018–19 price levels.*

7.1 Transitional arrangements for transitional and obsolete tariffs

Existing transitional and obsolete tariffs

Some business customers, including farmers and irrigators, are currently supplied under transitional or obsolete tariffs. These are legacy retail tariffs for which there is no corresponding network tariff; as a result, they cannot be determined under an N+R approach.

In previous price determinations, the QCA decided that most of these existing transitional and obsolete tariffs[128] should continue to be available for a transitional period, because some customers would face significant financial impacts if they were moved to a standard business tariff.

Submissions

Irrigation groups supported the continuation of transitional and obsolete tariffs. They considered that no standard business tariffs were suitable for irrigators, and that some customers would face significant bill increases.

QCA position

The QCA's draft decision is to maintain transitional arrangements for existing transitional and obsolete tariffs.

Data from Ergon Retail[129] shows that a significant number of customers currently on transitional and obsolete tariffs would be better off on standard business tariffs. However, some customers on existing transitional and obsolete tariffs continue to benefit from electricity tariffs that are below both the cost of standard business tariffs (which all other businesses in regional Queensland must pay) and the cost of supplying them with electricity. We therefore consider it appropriate to maintain existing transitional arrangements.

7.1.1 Transitional periods

In previous price determinations, the QCA determined that transitional and obsolete tariffs should be maintained for a transitional period to allow time for businesses to prepare for the transition to standard business tariffs and recoup some of the value of investments made to suit

[128] Tariffs 20 (large), 21, 22 (small and large), 37, 47, 48, 62, 65 and 66.
[129] See Appendix E.

the level and structure of transitional and obsolete tariffs. In the 2013–14 price determination, we determined that tariffs 20 (large), 21, 22 (small and large), 37, 62, 65 and 66 would be made available until 30 June 2020. In the 2017–18 price determination, we determined that tariffs 47 and 48 would be made available until 30 June 2022.

Submissions

Canegrowers Isis and Kalamia Cane Growers Organisation[130] (Kalamia) supported extending transitional periods for tariffs 62, 65 and 66 beyond 2020. The Bundaberg Regional Irrigators Group (BRIG) supported transitional and obsolete tariffs remaining available for existing customers until 2025. Cotton Australia supported allowing existing customers to remain on transitional tariffs indefinitely. The Kinchant Dam Water Users Association (Kinchant Dam) was concerned about transitional tariffs becoming obsolete, highlighting that usage charges in tariff 20 are significantly higher than off-peak charges in tariff 62. Irrigation groups considered that there were no standard business tariffs suitable for irrigators.

Energy Queensland supported tariffs 47 and 48 remaining available until 30 June 2022.

QCA position

The QCA's draft decision is to maintain existing transitional periods established in previous pricing determinations for transitional and obsolete tariffs. The QCA remains of the view that the transitional periods allowed for all transitional and obsolete tariffs are appropriate. Businesses will have had up to seven years to prepare for the transition to standard business tariff structures, which other regional businesses already face.

The QCA does not support allowing existing customers to remain on transitional tariffs indefinitely, as suggested by Cotton Australia. Doing so would result in current businesses receiving a perpetual cost advantage over all potential new entrant businesses, and be a barrier to entry in wider competitive markets.

In its response to a Queensland Productivity Commission inquiry on electricity pricing, the government did not support extending any transitional period[131], and has announced a range of programs, including the $20 million Business Energy Savers program to assist regional businesses on transitional and obsolete tariffs.

Given 2019–20 is the final year of the transitional period for most transitional and obsolete tariffs[132], we strongly encourage customers on these tariffs to contact their retailer as soon as possible for advice on the most appropriate tariffs for their business, and how best to adapt to standard business tariffs.

7.1.2 Access to transitional tariffs

In the 2013–14 price determination, the QCA decided that all business customers should have access to tariffs 20 (large), 21, 22 (small and large), 62, 65, and 66 throughout the transitional period, subject to individual tariff terms and conditions.[133] We made this decision so that all businesses eligible for these tariffs would be treated equitably.

In the 2018–19 price determination, we continued to allow open access to transitional tariffs.

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[130] While Kalamia's comment was directed specifically at the Queensland Government, we consider their support for extending transitional periods to be a relevant factor for the QCA to consider when making our draft determination on these tariffs.

[131] Queensland Government, November 2016, p. 11.

[132] Tariffs 47 and 48 will be available for existing customers until 30 June 2022.

[133] Tariff 37 cannot be accessed by new customers, as it was classified as obsolete on 1 July 2007.

The delegation requires the QCA to consider reclassifying transitional tariffs (i.e. tariffs 20 (large), 21, 22 (small and large), 37, 62, 65, and 66) as obsolete tariffs.

Submissions

Cotton Australia and Energy Queensland supported transitional tariffs being closed to new customers. Canegrowers Isis wanted all tariff options available to irrigators at all times, and did not support reclassifying transitional tariffs as obsolete. Canegrowers did not support reclassifying transitional tariffs, considering it premature to make a decision on reclassification prior to the AER approving Energy Queensland's regulatory proposal and tariff structure statements for 2020–25. The Queensland Farmers' Federation (QFF) argued for existing transitional and obsolete tariffs to be continued until the AER process is finalised.

QCA position

The QCA's draft decision is to reclassify transitional tariffs[134] as obsolete to new customers. Given these tariffs expire on 30 June 2020, the QCA agrees with Cotton Australia and the Minister that it is important that customers base all future business and investment decisions on standard business tariffs.

We disagree that it is premature to make a decision on the classification of these tariffs. While Energy Queensland's regulatory proposal and tariff structure statements for 2020–25 will have a bearing on standard business tariffs for that period, the QCA notes that transitional retail tariffs are not based on Energy Queensland's network tariffs. In addition, the QCA did not base transition periods on the AER process. Rather, after consultation with stakeholders, the decision was made on the basis of the depreciable life of irrigation infrastructure.

Classifying transitional tariffs as obsolete will still allow customers on tariffs 20 (large), 21, 22 (small and large), 62, 65, and 66 to remain on their current tariff until their expiry on 30 June 2020—while also ensuring that customers changing tariffs, and new customers, move to standard business tariffs.

While these tariffs are not a factor in our draft determination, the QCA notes that they will still be in operation when the AER process is finalised in April 2020.

7.1.3 Escalation of transitional and obsolete tariffs

Unlike other tariffs, transitional and obsolete tariff charges are not determined through an N+R approach. In past price determinations, the QCA's general approach[135] to setting charges for each transitional and obsolete tariff was to adjust the charges based on the percentage increase in the charges in the standard business tariff that customers would otherwise pay. We then applied additional escalation factors to these increases to limit charges for transitional and obsolete tariffs falling further below cost in dollar terms.[136] Escalation factors of 1.1, 1.25 or 1.5 were applied, depending on the gap between customer bills under transitional and obsolete tariffs and corresponding standard business tariffs. Where the largest proportion of customer bills would likely be impacted by 10 per cent or less, an escalation factor of 1.1 was applied;

[134] Tariffs 20 (large), 21, 22 (small and large), 62, 65, and 66.

[135] In the 2015–16 and 2018–19 determinations, charges in standard business tariffs fell. We determined that maintaining charges in transitional and obsolete tariffs at their previous levels would be sufficient to limit these charges from falling further below cost in dollar terms.

[136] As any given percentage increase in a higher bill (such as for a standard business tariff) will be greater, expressed in dollar terms, than the same percentage increase in a smaller bill (such as for a transitional or obsolete tariff). For example, if two bills of $1,000 and $2,000 each increased by 10 per cent to $1,100 and $2,200 respectively, the dollar difference between them would increase from $1,000 to $1,100.

where impacts were between 10 per cent and 100 per cent, an escalation factor of 1.25 was applied; and where impacts exceeded 100 per cent, an escalation factor of 1.5 was applied.

Where standard business tariffs fell in price, the QCA did not increase transitional prices or apply escalation factors—as the reduction in standard business tariffs acted to somewhat reduce the difference between transitional and standard business tariffs in dollar terms.

In 2018–19, where the prices of standard business tariffs fell, the QCA maintained transitional and obsolete tariffs at their existing price levels.

Submissions

Cotton Australia argued that transitional escalation factors should be applied to price decreases. Irrigator groups highlighted the significant price increases which have occurred in the past, which have impacted both on-farm costs and water prices.

QCA position

The QCA has maintained transitional and obsolete tariffs at their existing price levels. Given that standard business tariffs are forecast to decrease, we consider it is unnecessary to increase transitional prices or apply escalation factors—as the reduction in standard business tariffs will act to somewhat reduce the difference between transitional and standard business tariffs in dollar terms. This approach is consistent with our 2015–16 and 2018–19 price determinations, where standard business tariffs also decreased.

7.2 Draft determination on transitional arrangements

Table 18 outlines our draft determination on transitional arrangements for 2019–20.

Table 18 Transitional arrangements for 2019–20

Obsolete tariff	*Tariff expiry date*	*2019–20 price change (%)*
Tariff 20 (large)	30 June 2020	0
Tariff 21	30 June 2020	0
Tariff 22 (small and large)	30 June 2020	0
Tariff 37	30 June 2020	0
Tariff 47	30 June 2022	0
Tariff 48	30 June 2022	0
Tariff 62	30 June 2020	0
Tariff 65	30 June 2020	0
Tariff 66	30 June 2020	0

8 DRAFT DETERMINATION

This chapter sets out our draft determination of regulated retail electricity prices (notified prices) to apply from 1 July 2019 to 30 June 2020, as well as draft customer impacts.

Under the network plus retail (N+R) costs approach, retail tariffs are aligned with network tariffs regulated by the AER. The network tariffs used to develop draft retail tariffs are discussed in Chapter 3.

Chapters 4, 5 and 6 set out our draft decisions on energy costs; retail costs, which comprise the R component of the retail tariff calculation; and other issues.

Chapter 7 sets out our draft decisions on notified prices and transitional arrangements for retail tariffs that have been declared transitional or obsolete.

The draft tariff schedule for 2019–20 is provided in Appendix F. The draft regulated retail tariffs and notified prices are published in a tariff schedule, which includes other information, such as the eligibility criteria and terms and conditions for each tariff.

The tables in section 8.1 set out draft regulated retail tariffs and prices for 2019–20. All draft tariffs in section 8.1 exclude goods and services tax (GST).

8.1 Notified prices

Table 19 Regulated retail tariffs and prices for residential customers (excl. GST), 2019–20

Retail tariff	*Fixed charge*[a]	*Usage charge (peak)*	*Usage charge (flat/off-peak)*	*Demand charge (peak)*	*Demand charge (off-peak)*
	c/day	*c/kWh*	*c/kWh*	*$/kW/mth*	*$/kW/mth*
Tariff 11—residential (flat rate)	90.812		23.709		
Tariff 12A—residential (time-of-use)[b]	83.657	61.866	19.473		
Tariff 14—residential (time-of-use demand)[c]	45.109		15.532	61.691	8.859
Tariff 31—night rate (super economy)			17.973		
Tariff 33—controlled supply (economy)			19.284		

a *Charged per metering point.*

b *Peak—3 pm to 9.30 pm (December, January and February); off-peak—all other times.*

c *Peak demand—3 pm to 9.30 pm (December, January and February); off-peak demand—3 pm to 9.30 pm (March to November).*

Table 20 Regulated retail lifestyle tariff and prices for residential customers (excl. GST), 2019–20

Retail tariff	***Fixed charge (Band 1)***[a]	***Fixed charge (Band 2)***[b]	***Fixed charge (Band 3)***[c]	***Fixed Charge (Band 4)***[d]	***Fixed charge (Band 5)***[e]	***Usage charge***	***Top-up charge***[f]
	$/mth	***$/mth***	***$/mth***	***$/mth***	***$/mth***	***c/kWh***	***$/kWh/ mth***
Tariff 15—residential	25.885	42.296	58.707	75.117	91.528	15.415	9.641

a *Band 1 (no network access allowance included during the summer peak window (SPW), where the SPW is defined as November to March, any day between 4 pm and 9 pm).*

b *Band 2 (up to 5 kWh network access allowance included during the SPW).*

c *Band 3 (up to 10 kWh network access allowance included during the SPW).*

d *Band 4 (up to 15 kWh network access allowance included during the SPW).*

e *Band 5 (up to 20 kWh network access allowance included during the SPW).*

f *The summer peak top-up charge is applicable to the single maximum daily energy consumed above the limit of the customer's nominated access band during the month. This top-up charge is only applicable to network use during the SPW, i.e. November to March, any day between 4 pm and 9 pm. Once the network access allowance for the chosen band has been exceeded, the exceeded amount (in kWh) remains available for the customer for the rest of the month until the allowance is reset back to the original nominated allowance at the start of the coming month.*

Table 21 Regulated retail tariffs and prices for small business and unmetered supply customers, other than street lighting (excl. GST), 2019–20

Retail tariff	***Fixed charge***[a]	***Usage charge (peak)***	***Usage charge (flat/off-peak)***	***Demand charge (peak)***	***Demand charge (off-peak/flat)***
	c/day	***c/kWh***	***c/kWh***	***$/kW/mth***	***$/kW/mth***
Tariff 20—business (flat rate)	125.589		23.918		
Tariff 22A—business (time-of-use)[b]	125.589	59.572	22.394		
Tariff 24—business (time-of-use demand)[c]	61.778		16.379	81.342	8.174
Tariff 41—low voltage (demand)	540.969		14.600		22.451
Tariff 91—unmetered			21.510		

a *Charged per metering point.*

b *Peak—10 am to 8 pm on weekdays (December, January and February); off-peak—all other times.*

c *Peak demand—10 am to 8 pm on weekdays (December, January and February); off-peak demand—10 am to 8 pm on weekdays (March to November).*

Table 22 Regulated retail tariffs and prices for large business and street lighting customers (excl. GST), 2019–20

Retail tariff	***Fixed charge***	***Usage charge (peak)***	***Usage charge (flat/off-peak)***	***Demand charge (peak)***	***Demand charge (off-peak/flat)***
	c/day	***c/kWh***	***c/kWh***	***$/kW/mth***	***$/kW/mth***
Tariff 44—over 100 MWh small (demand)	4580.008		12.410		36.300
Tariff 45—over 100 MWh medium (demand)	15330.070		12.410		26.855
Tariff 46—over 100 MWh large (demand)	40247.824		12.398		22.002
Tariff 50—over 100 MWh seasonal time-of-use (demand)[a]	3570.587	12.054	14.533	66.860	11.646
Tariff 71—street lighting[b]	0.420		28.416		

a *Peak demand is charged on maximum metered demand exceeding 20 kW on weekdays between 10 am and 8 pm in summer months (December, January and February). Off-peak demand is charged on maximum metered demand exceeding 40 kW during non-summer months (March to November). Peak usage is charged on all usage in summer months (December, January and February). Off-peak usage is charged on all usage during non-summer months (March to November).*

b *The fixed charge for street lighting applies to each lamp.*

Table 23 Regulated retail tariffs and prices for very large business customers (excl. GST), 2019–20

Retail tariff	*Fixed charge*	*Usage charge (peak)*	*Usage charge (flat/off-peak)*	*Connection unit*	*Capacity (flat/off-peak)*	*Demand charge (flat/peak)*	*Excess reactive power charge*
	c/day	*c/kWh*	*c/kWh*	*$/day/unit*	*$/kVA of AD/mth*	*$/kVA/mth*	*$/excess kVAr/mth*
Tariff 51A—over 4 GWh high voltage (CAC 66kV)	22977.574		11.953	10.339	4.540	2.739	4.454
Tariff 51B—over 4 GWh high voltage (CAC 33kV)	16084.324		11.953	10.339	5.574	2.823	4.454
Tariff 51C—over 4 GWh high voltage (CAC 22/11kV Bus)	14599.624		11.957	10.339	6.488	3.424	4.454
Tariff 51D—over 4 GWh high voltage (CAC 22/11kV Line)	13751.224		11.978	10.339	12.708	6.905	4.454
Tariff 52A—over 4 GWh high voltage (CAC STOUD 33/66kV)[a]	10251.574	11.473	11.884	10.339	6.945	12.248	4.454
Tariff 52B—over 4 GWh high voltage (CAC STOUD 22/11kV Bus)[a]	10251.574	11.477	11.888	10.339	4.890	46.137	4.454
Tariff 52C—over 4 GWh high voltage (CAC STOUD 22/11kV Line)[a]	10251.574	11.498	11.909	10.339	8.999	80.540	4.454
Tariff 53—over 40 GWh high voltage (ICC)[b]	13560.395		11.978		12.708	6.905	4.454

a Peak demand is charged on maximum kVA demand during summer peak demand window times (weekdays between 10 am and 8 pm in December, January and February). Off-peak capacity is charged on the greater of either the customer's kVA authorised demand (AD) or the actual monthly half-hour maximum kVA demand. The actual monthly maximum demand is measured all year excluding summer peak demand window times (all year excluding weekdays between 10 am and 8 pm in December, January and February). Peak usage is charged on all usage in summer months (December, January and February). Off-peak usage is charged on all usage during non-summer months (March to November).

b Ergon Distribution advised that ICCs do not incur connection unit charges on a network level.

Table 24 Obsolete regulated retail tariffs and prices (excl. GST), 2019–20

Retail tariff	***Fixed charge***	***Minimum charge***	***Usage rate 1[a]***	***Usage rate 2[b]***	***Usage rate 3[c]***	***Usage rate (flat)***	***Capacity (up to 7.5kw)***	***Capacity (over 7.5kw)***
	c/day	***c/day***	***c/kWh***	***c/kWh***	***c/kWh***	***c/kWh***	***$/kW/yr***	***$/kW/yr***
Tariff 20 (large)—obsolete	76.858					37.595		
Tariff 21—obsolete		72.631	49.357	46.374	35.303			
Tariff 22 (small and large)—obsolete	184.717		49.820		17.543			
Tariff 37[d]—obsolete		30.623	21.807		54.544			
Tariff 62—obsolete	78.451		46.516	39.336	16.448			
Tariff 65—obsolete	78.003		36.894		20.321			
Tariff 66—obsolete	171.915					19.338	37.503	112.759

a *Tariff 21—first 100 kWh; tariff 22—7 am to 9 pm Mon. to Fri.; tariff 37—10.30 pm to 4.30 pm; tariff 62—7 am to 9 pm Mon. to Fri., first 10,000kWh; tariff 65—12hr peak.*

b *Tariff 21—101 to 10,000 kWh; tariff 62—7 am to 9 pm Mon. to Fri., over 10,000 kWh.*

c *Tariff 21—over 10,000 kWh; tariff 22—all other times; tariff 37—4.30 pm to 10.30 pm; tariffs 62 & 65—all other times.*

d *Tariff 37 became obsolete on 1 July 2007. It is only available to customers taking continuous supply under tariff 37 from 30 June 2007.*

Table 25 Obsolete high voltage regulated retail tariffs and prices (excl. GST), 2019–20

Retail tariff	*Fixed charge*	*Usage charge (flat/off-peak)*	*Demand charge (off-peak/flat)*
	c/day	*c/kWh*	*$/kW/mth*
Tariff 47—obsolete	44689.726	12.446	27.864
Tariff 48—obsolete	46712.140	12.874	28.822

8.2 Customer impacts

What impact does the QCA's price determination have on customer bills?

Figures 17–19 compare the annual amount typical customers[137] would have paid under 2018–19 notified prices, with the annual amount they would pay under the draft 2019–20 notified prices. Customers will also incur metering charges in addition to the amounts shown in these figures. Customers' metering charges will vary depending on a range of factors, including the type of meter they have installed, the number of different tariffs they use and whether they have a solar photovoltaic system. As these charges vary from customer to customer, they have not been included in the customer impact analysis.

Residential customers

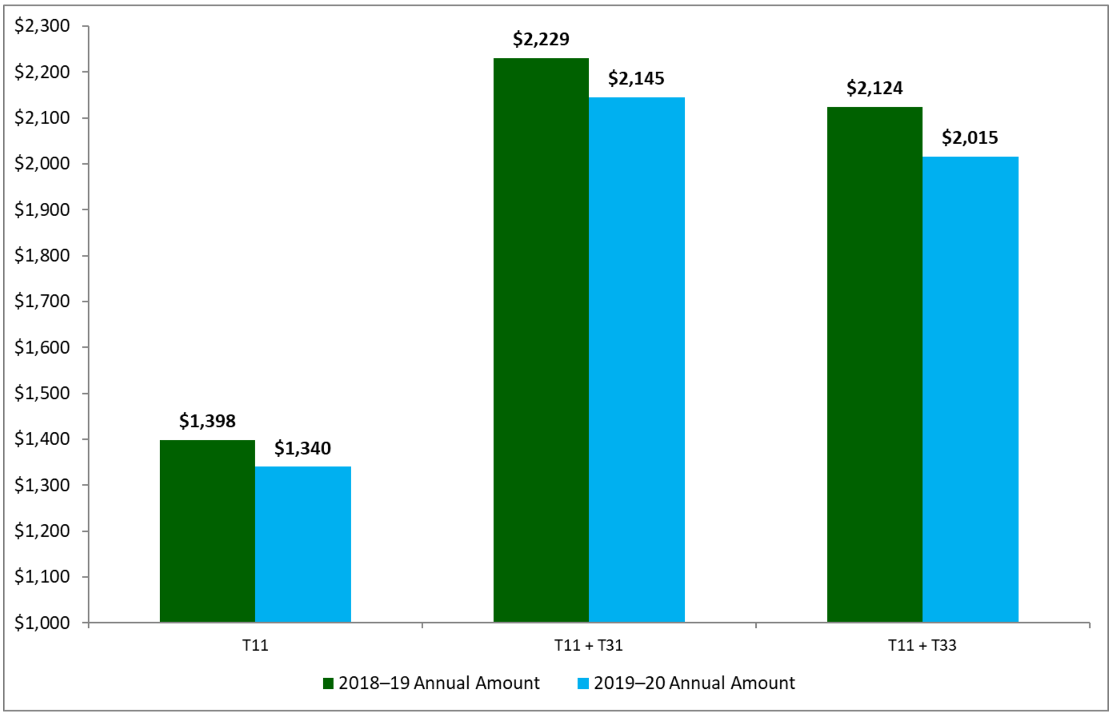
The main retail tariff for residential customers is tariff 11. Many customers on tariff 11 are also on one of the controlled load tariffs (tariffs 31 and 33).[138]

A typical residential customer on tariff 11 would pay around $58 (4.1 per cent) less per annum for their electricity usage and service fee in 2019–20. A typical residential customer on a combination of tariffs 11 and controlled load tariff 31 would pay around $84 (3.8 per cent) less per annum, while a typical customer on a combination of tariff 11 and controlled load tariff 33 would pay around $109 (5.1 per cent) less per annum. However, the impact on each individual will vary according to their consumption.

[137] The typical customer for a given retail tariff is the median or middle customer in terms of consumption out of all customers on that tariff in regional Queensland. The typical customer consumption data is provided by Ergon Retail. More information appears in Appendix G.

[138] Controlled load tariffs may be used for appliances such as water heaters and pool pumps. These tariffs are cheaper than tariff 11, as customers are only guaranteed supply for a set number of hours (tariff 31 guarantees supply for eight hours per day and tariff 33 guarantees supply for 18 hours per day).

Figure 17 Impact of the change in notified prices on typical residential customers (incl. GST), 2019–20



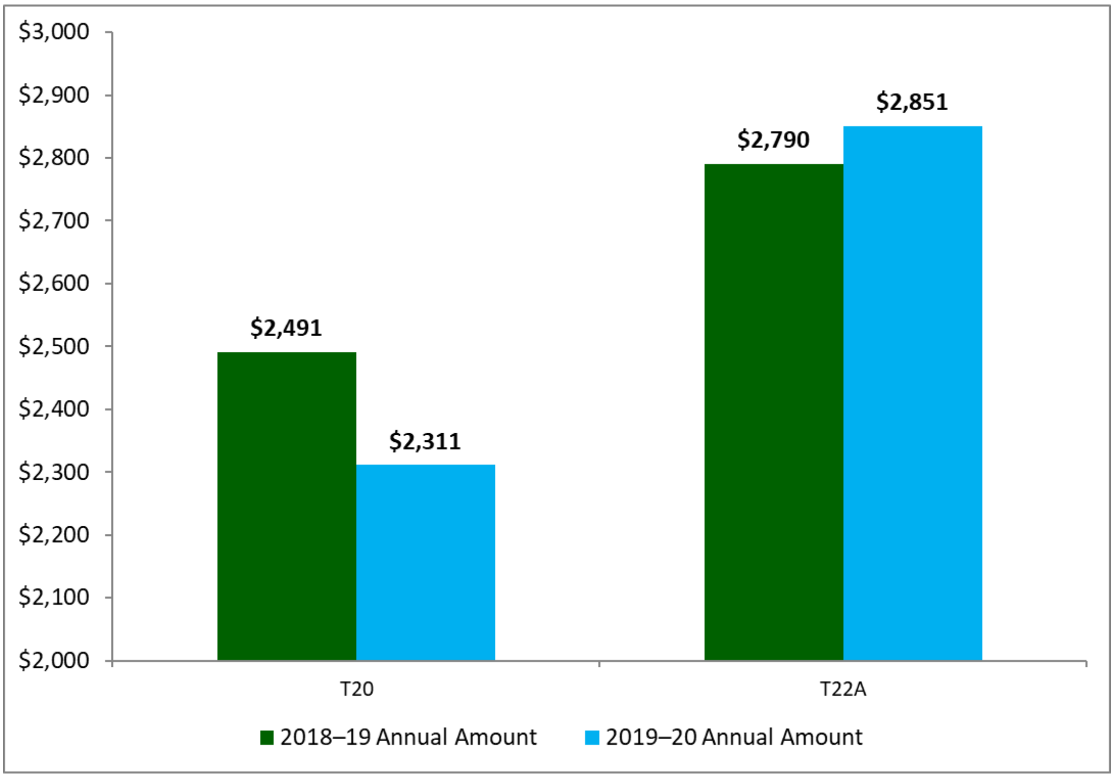
Note: Annual amounts have been rounded to the closest dollar.

Small business customers

A typical small business customer on tariff 20 would pay around $180 (7.2 per cent) less per annum for their electricity usage and service fee in 2019–20. A typical small business customer on tariff 22A would pay around $61 (2.2 per cent) more per annum for their electricity usage and service fee in 2019–20.[139] However, the impact on each individual business will vary according to their consumption and, if the customer is on tariff 22A, the pattern of their consumption.

[139] This increase is primarily driven by higher network charges for the peak period.

Figure 18 Impact of the change in notified prices on typical small business customers (incl. GST), 2019–20

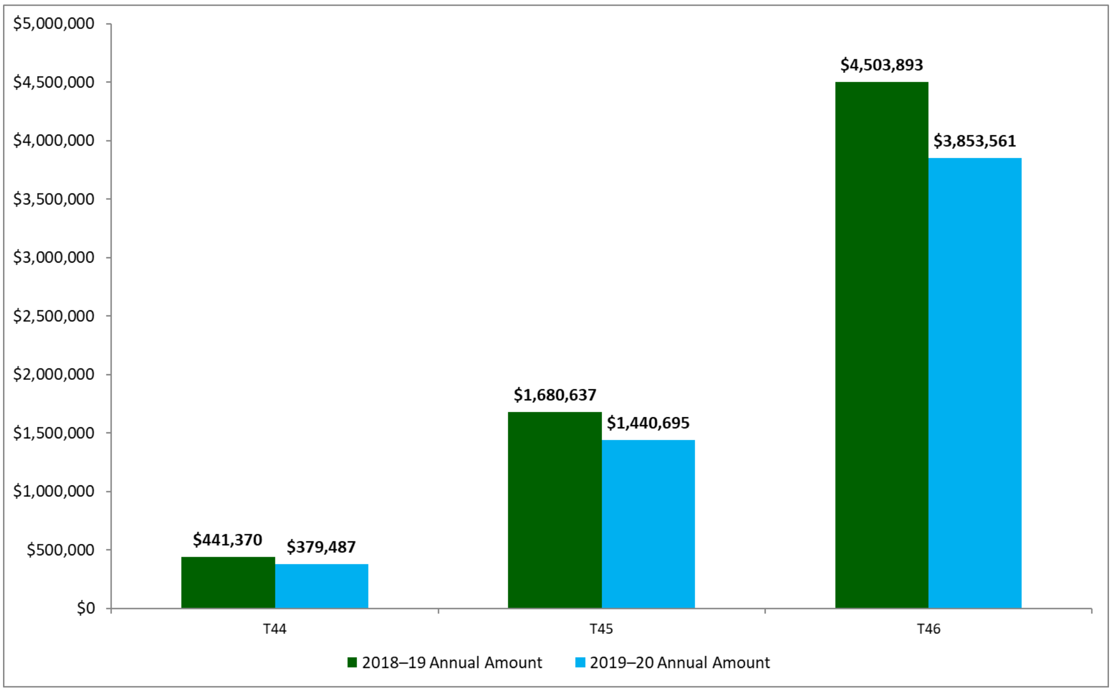


Note: Annual amounts have been rounded to the closest dollar.

Large business customers

A typical large business customer on one of tariffs 44, 45 or 46 would pay between 14 per cent and 14.4 per cent less per annum for their electricity usage and service fee in 2019–20. However, it is important to note that bill impacts for individual customers will vary depending on their level and pattern of consumption.

Figure 19 Impact of the change in notified prices on typical large business customers (incl. GST), 2019–20



Note: Annual amounts have been rounded to the closest dollar.

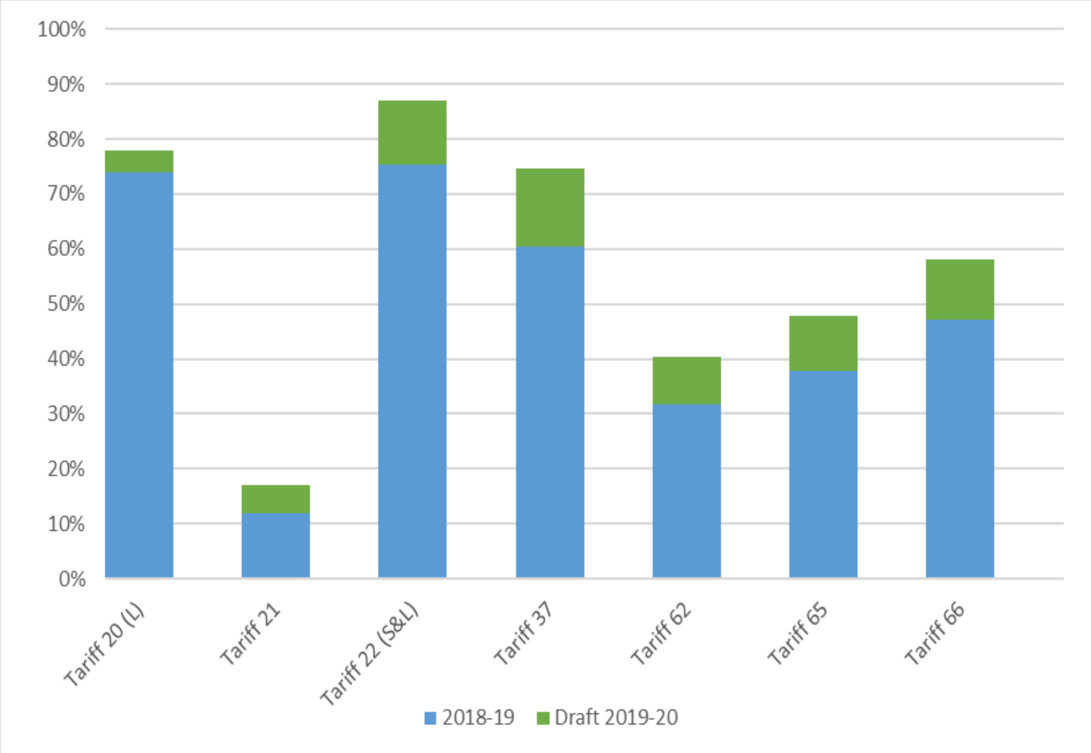
Transitional and obsolete tariff customers

Around 35,000 connections, including some used by farmers and irrigators, are supplied under legacy retail tariffs. These tariffs were made available for several years to allow customers to transition their businesses to standard business tariffs. With the exception of tariffs 47 and 48, all of these tariffs will expire on 30 June 2020. In accordance with the delegation, the QCA's draft determination is to allow existing customers to remain on these tariffs until they expire, but close these tariffs to new customers. This is to ensure that businesses are not making investment decisions based on tariffs that will shortly expire.

A significant number of customers on these expiring tariffs would be better off on the standard business tariffs other regional businesses must pay. According to data from Ergon Retail, over 30 per cent of connections on expiring tariffs would have saved money on standard business tariffs. Based on the 2019–20 draft prices, around 40 per cent of all connections on expiring tariffs would save money on standard business tariffs in 2019–20. Figure 20 shows these figures for each obsolete tariff.

In addition, it is possible that even more small business customers could save on time-of-use tariffs.

Figure 20 Approximate proportion of connections for each expiring obsolete tariff that could transition to standard business tariffs without any negative impact



Given these tariffs will shortly expire, and the significant potential for customers to pay less for electricity on standard business tariffs, we strongly encourage customers on expiring tariffs to contact their retailer for advice on the most appropriate tariffs for their business.

Tariffs 47 and 48

Around 60 large business connections are supplied through tariffs 47 or 48. While these tariffs will remain available until 30 June 2022, as figure 21 shows, a significant number of customers could be better off on standard business tariffs. We encourage customers on these tariffs to contact their retailer to see if they could benefit from moving to standard business tariffs before tariffs 47 and 48 expire.

Figure 21 Proportion of connections on tariffs 47 and 48 that could transition to standard business tariffs without any negative impact

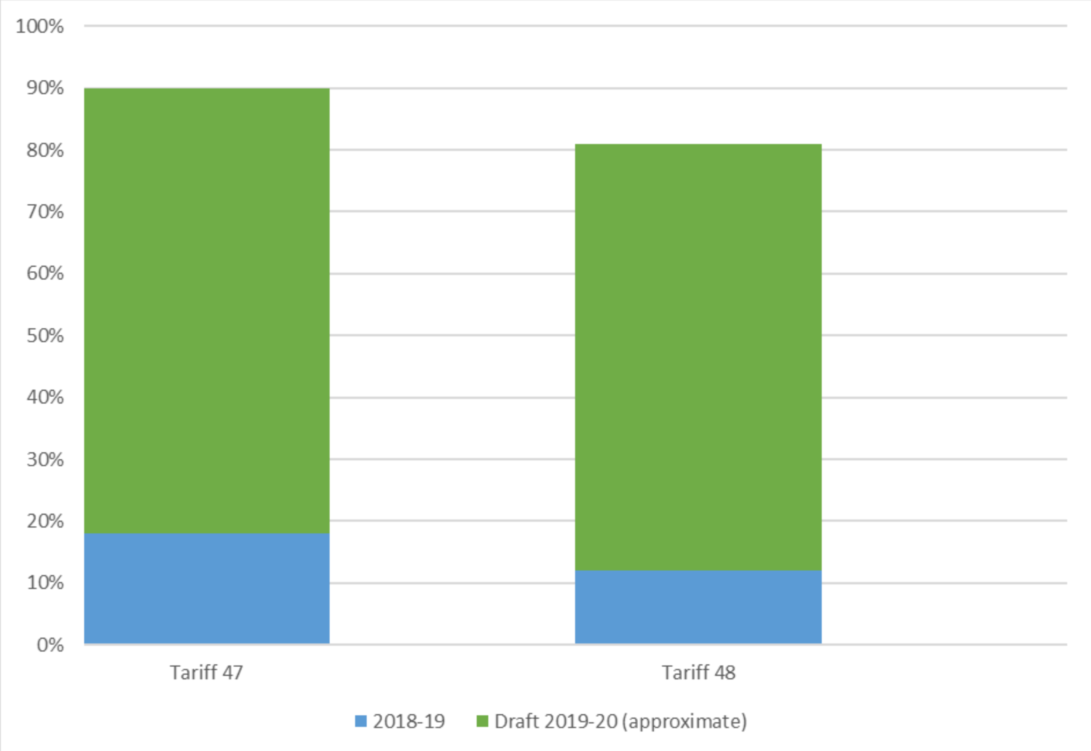


Table 26 Transitional arrangements for 2019–20

Obsolete tariff	***Tariff expiry date***	***2019–20 price change (%)***
Tariff 20 (large)	30 June 2020	0
Tariff 21	30 June 2020	0
Tariff 22 (small and large)	30 June 2020	0
Tariff 37	30 June 2020	0
Tariff 47	30 June 2022	0
Tariff 48	30 June 2022	0
Tariff 62	30 June 2020	0
Tariff 65	30 June 2020	0
Tariff 66	30 June 2020	0

8.3 Metering charges

The majority of electricity customers pay metering charges that reflect the capital cost and operation of their meter. Metering charges for most customers are regulated by the Australian Energy Regulator (AER) and are not part of notified prices.

As was the case for 2018–19, the 2019–20 delegation excludes the setting of metering charges for residential and small business customers. The Minister has again asked the QCA for separate advice relating to metering charges for these customers—see our website for more information.

As with the 2018–19 price determination, the QCA has separated large customer non-AER regulated metering costs from retail operating costs, and has published these metering charges separately. This means a potential barrier to competition in the contestable market for large customer metering remains removed, and ensures only customers with advanced digital meters provided by a metering coordinator appointed by Ergon Retail will be required to pay Ergon Retail for non-AER regulated metering services.[140] Table 27 shows metering fees for large customers supplied via advanced digital meters.

Table 27 Metering charges for large and very large business customers

Customer type	***Metering charge (c/day)***
Standard asset customer	160.761
Standard asset customer (large)	202.308
Connection asset customer	430.801
Individually calculated customer	434.813

Source: Retailer data.

[140] See Chapter 5 for further information.

GLOSSARY

AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AFMA	Australian Financial Markets Association
CAC	Connection Asset Customer
CARC	Customer acquisition and retention costs
CCIQ	Chamber of Commerce and Industry Queensland
CER	Clean Energy Regulator
CLP	Controlled load profile
CPI	Consumer price index
CSO	Community service obligation
c/day	Cents per day
Delegation	The delegation issued by the Minister for Natural Resources, Mines and Energy on 20 December 2018 (see Appendix A).
DMO	Default market offer
Energex	Energex Distribution
Ergon Distribution	Ergon Energy Corporation Limited (electricity distribution arm)
Ergon Retail	Ergon Energy Queensland Pty Ltd (electricity retail arm)
Electricity Act	Electricity Act 1994 (Qld)
ESC	Essential Services Commission (Victoria)
ESCOSA	Essential Services Commission of South Australia
GST	Goods and services tax
GWh	Gigawatt hour
HVL	High voltage line
ICC	Individually calculated customer
ICP	Interim consultation paper
IPART	Independent Pricing and Regulatory Tribunal
kWh	Kilowatt hour
kVA	Kilovolt Ampere
kVr	Kilovolt reactive
LGC	Large-scale generation certificate
LHS	Left hand side
LRET	Large-scale renewable energy target

LRMC	Long-run marginal cost
MWh	Megawatt hour
N	Network costs
NECF	National Energy Customer Framework
NEM	National Electricity Market
NERL	National Energy Retail Law
NERR	National Energy Retail Rules
Notified prices	Regulated retail electricity prices
NSLP	Net system load profile
N+R	Network + Retail cost build-up methodology
NSW	New South Wales
PSW	Peak summer window
PV	Photovoltaic
QCA	Queensland Competition Authority
QCA Act	Queensland Competition Authority Act 1997
QCOSS	Queensland Council of Social Service
QEUN	Queensland Electricity Users Network
QFF	Queensland Farmers' Federation
QPC	Queensland Productivity Commission
R	Energy and retail costs
RET	Renewable energy target
RHS	Right hand side
ROC	Retail operating costs
RPP	Renewable power percentage
SA	South Australia
SAC	Standard asset customer
SOA	Standing offer adjustment
SPW	Summer peak window
SRES	Small-scale renewable energy scheme
STC	Small-scale technology certificate
STOUD	Seasonal time-of-use demand
STP	Small-scale technology percentage
UTP	Uniform Tariff Policy

APPENDIX A: DELEGATION

Queensland Government

The Hon Dr Anthony Lynham MP
Minister for Natural Resources, Mines and Energy

Ref CTS 27475/18

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Professor Flavio Menezes
Chair
Queensland Competition Authority
Level 27, 145 Ann Street
BRISBANE QLD 4000

Dear Professor Menezes

I write to you to issue a delegation and terms of reference to the Queensland Competition Authority (QCA) for the determination of regulated retail electricity prices in regional Queensland for 2019–20 under section 90AA(1) of the *Electricity Act 1994*.

The government's uniform tariff policy (UTP) and promoting greater levels of retail competition are important considerations when setting regulated retail electricity prices in regional Queensland. The attached delegation and terms of reference for 2019–20 are generally consistent with the approaches in my delegation and terms of reference for 2018–19, however, there are some additional considerations. These include more clearly defining the intent of the standing offer adjustment, excluding the determination of metering charges for small customers, the status of transitional tariffs and clarifying the approach for Tariff 15.

The government is aware of the divergence in standing offers and market offers in the South East Queensland (SEQ) electricity market, as identified in your quarterly SEQ market monitoring reports. As such, I consider that standing offer prices in the SEQ market no longer provide an appropriate reference point for setting prices in regional Queensland. However, the government holds the view that standard contracts provide additional value to customers compared to market contracts, for example, through additional protections contained in the terms and conditions of standard contracts.

In order to reflect the intent of the UTP, the QCA should give consideration to including an adjustment in notified prices that appropriately reflects the additional value of the terms and conditions of standard retail contracts. I also consider the standing offer adjustment made by the QCA in previous determinations appropriately reflects this additional value and as such, the QCA should consider including an adjustment of a similar magnitude in notified prices for 2019–20.

Under Power of Choice reforms, all new and replacement meters must be advanced digital meters. Due to my concerns about the impact the cost of these meters would have on customers, on 26 April 2018, I asked the QCA to provide advice on the charges regional residential and small business customers should face on the basis of advanced digital meter costs being spread across those customers. This contrasted to the alternative approach of applying those costs only to customers receiving the new meters. As the government remains concerned about the cost of digital meters for small customers, this delegation excludes the determination of notified prices for retail metering services for residential and small business customers. I am separately issuing a direction notice to the QCA seeking advice similar to that I sought in April 2018.

The government is committed to customers in regional Queensland having more choice in electricity tariffs while maintaining the UTP. With this in mind, the government supports efforts by Ergon Energy to develop new tariff structures in regional Queensland. The government encourages the QCA and Ergon Energy to consult closely in determining charges for Tariff 15.

In addition to customers having more choice in tariffs, the government also considers more choice in products to be equally important. Last year, the government introduced EasyPay Reward, which was designed to provide regional electricity customers with another product in the market where households and small business customers could make real savings. The government is committed to delivering lower electricity bills, is further investigating options for regional customers and will consult with the QCA on specific wording for the 2019–20 gazette, while ensuring regional customers continue to benefit from the electricity cost protection provided by the UTP.

I understand that since 2012–13, the QCA has been gradually phasing-out legacy retail tariffs for businesses in regional Queensland, as they are not based on the actual costs of supplying electricity. Transitional tariffs are set to expire in 2019–20 and all customers on transitional tariffs will need to switch to a standard business tariff before 1 July 2020. To assist in this process and ensure new businesses make investment decisions based on the cost of standard business tariffs, the QCA should consider making all transitional tariffs 'obsolete' so that new customers cannot access these tariffs for the short remaining period of 2019–20. The government recognises that some customers currently accessing transitional tariffs will face challenges adjusting to standard business tariffs. To assist these customers, the government is delivering a range of programs including the $20 Million Business Energy Savers Program, as part of our Affordable Energy Plan. In addition, these customers will continue to be supported through the UTP.

Public consultation is a vital part of the QCA's process for determining retail electricity prices. In this regard, the terms of reference requires the draft determination to be issued in February 2019, consultation to occur and a final determination to be delivered by 31 May 2019.

If you have any questions, please contact Ms Gayle Leaver, General Manager, Consumer Strategy and Innovation, Department of Natural Resources, Mines and Energy who will be pleased to assist you and can be contacted on 3199 4907.

Yours sincerely

Dr Anthony Lynham MP
Minister for Natural Resources, Mines and Energy

Att

ELECTRICITY ACT 1994
Section 90AA(1)

DELEGATION

I, Anthony Lynham, the Minister for Natural Resources, Mines and Energy, in accordance with the power of delegation in section 90AA(1) of the *Electricity Act 1994* (the Act), delegate to the Queensland Competition Authority (QCA) the function under section 90(1) of the Act of deciding the prices that a retail entity may charge its Standard Contract Customers for customer retail services in Queensland, other than those in the Energex distribution area, for the tariff year 1 July 2019 to 30 June 2020.

The following are the Terms of Reference of the price determination:

Terms of Reference

1. These Terms of Reference apply for the tariff year 1 July 2019 to 30 June 2020.

2. The QCA is to calculate the notified prices, other than the notified prices associated with the provision of residential and small business customer retail metering services, and publish an annual price determination, in the form of a tariff schedule, in accordance with these Terms of Reference.

3. In accordance with section 90(5)(a) of the Act, in making a price determination for each tariff year the QCA must have regard to the matters set out in paragraph 5 of these Terms of Reference.

4. In accordance with section 90(5)(b) of the Act, the QCA may have regard to any other matter that the QCA considers relevant.

5. The matters that the QCA is required by this delegation to consider are:

    (a) On 1 July 2016, price regulation in the Energex distribution area was removed for small customers. This means that notified prices do not apply to customers in the Energex distribution area;

    (b) Uniform Tariff Policy—QCA must consider the Government's Uniform Tariff Policy, which provides that, wherever possible, customers of the same class should pay no more for their electricity, regardless of their geographic location. However, as residential and small business customers paying notified prices are on standard retail contracts, the Government is of the view that QCA must consider incorporating into notified prices, an appropriate value reflecting the more favourable terms and conditions of standard retail contracts compared to market contracts;

(c) Framework – use of the Network (N) plus Retail (R) cost build-up methodology when working out the notified prices and making the price determination, where N (network cost) is treated as a pass-through and R (energy and retail cost) is determined by the QCA;

(d) When determining the N components for each regulated retail tariff:

(i) For residential and small business customer tariffs (with the exception of Tariffs 12A, 14, 15, 22A and 24) - basing the network cost component on the network charges to be levied by Energex and the relevant Energex tariff structures;

(ii) For Tariffs 12A, 14, 15, 22A and 24 - basing the network cost component on the price level of network charges to be levied by Energex, but utilising the relevant EECL tariff structures, in order to strengthen or enhance the underlying network price signals and encourage customers to switch to time-of-use and demand tariffs and reduce their energy consumption during peak times; and

(iii) For large business customers who consume 100MWh or more per annum - basing the network cost component on the network charges to be levied by EECL;

(e) Transitional Arrangements – The QCA should consider reclassifying transitional tariffs as obsolete tariffs (i.e. Tariffs 20 (large), 21, 22 (small and large), 37, 62, 65, and 66).

(f) Continue enabling retailers to also charge Standard Contract Customers for the following customer retail services that are not included in regulated retail tariffs:

(i) Amounts in accordance with a program or scheme for the purchase of electricity from renewable or environmentally-friendly sources (whether or not those additional amounts are calculated on the basis of the customer's electricity usage), but only if:
(a) the customer voluntarily participates in such program or scheme;
(b) the additional amount is payable under the program or scheme; and
(c) the retailer gives the customer prior written notice of any change to the additional amount payable under the program or scheme;

(g) Continuing Ergon Energy Queensland Pty Ltd's EasyPay Reward scheme.

Interim Consultation Paper

6. The QCA must publish an interim consultation paper identifying key issues to be considered when making the price determination.

7. The QCA must publish a written notice inviting submissions about the interim consultation paper. The notice must state a period during which anyone can make written submissions to the QCA about issues relevant to the price determination.

8. The QCA must consider any submissions received within the consultation period and make them available to the public, subject to normal confidentiality considerations.

Consultation Timetable

9. The QCA must publish an annual consultation timetable within two weeks after submissions on the interim consultation paper are due, which can be revised at the discretion of the QCA, detailing any proposed additional public papers and workshops that the QCA considers would assist the consultation process.

Workshops and additional consultation

10. As part of the interim consultation paper and in consideration of submissions in response to the interim consultation paper, the QCA must consider the merits of additional public consultation (workshops and papers) on identified key issues.

Draft Price Determination

11. The QCA must investigate and publish its draft price determination on regulated retail electricity tariffs, with each tariff to be presented as bundled prices appropriate to the retail tariff structure.

12. The QCA must publish a written notice inviting submissions about the draft price determination. The notice must state a period during which anyone can make written submissions to the QCA about issues relevant to the draft price determination.

13. The QCA must consider any submissions received within the consultation period and make them available to the public, subject to normal confidentiality considerations.

Final Price Determination

14. The QCA must investigate and publish its final price determination on regulated retail electricity tariffs, with each tariff to be presented as bundled prices appropriate to the retail tariff structure, and gazette the retail tariffs.

Timing

15. The QCA must make its reports available to the public and, at a minimum, publicly release the papers and price determinations listed in paragraphs 6 to 14.

16. The QCA must publish the interim consultation paper for the 2019–20 tariff year no later than one month after the date of this Delegation.

17. The QCA must publish the draft price determination on regulated retail electricity tariffs in February 2019.

18. The QCA must publish the final price determination on regulated retail electricity tariffs for the 2019–20 tariff year, and have the retail tariffs gazetted, no later than 31 May 2019.

DATED this 17/12/18 day of MMMM 2018.

SIGNED by the Honourable)
Anthony Lynham,) ....
Minister Natural Resources, Mines and Energy) *(signature)*

APPENDIX B: SUBMISSIONS AND REFERENCES

Submissions

The QCA has received 13 submissions on its interim consultation paper before releasing this draft determination. Non-confidential submissions are available on the QCA's website.

Stakeholder	*Abbreviated form*	*Submission number*	*Date received*
Bundaberg Regional Irrigators Group	BRIG	1	18 January 2019
Cotton Australia	Cotton Australia	2	21 January 2019
Canegrowers Isis	Canegrowers Isis	3	16 January 2019
Canegrowers	Canegrowers	4	18 January 2019
Energy Queensland	Energy Queensland	5	25 January 2019
Kalamia Cane Growers Organisation	Kalamia	6	15 January 2019
Kinchant Dam Water Users Association	Kinchant Dam	7	18 January 2019
Origin Energy	Origin Energy	8	18 January 2019
Pioneer Valley Water Co-operative	Pioneer Valley	9	18 January 2019
Queensland Council of Social Service	QCOSS	10	18 January 2019
Queensland Consumers' Association	Queensland Consumers' Association	11	17 January 2019
Queensland Farmers' Federation	QFF	12	18 January 2019
Confidential submission	–	–	14 January 2019

References

ACIL Allen Consulting (ACIL Allen), *Estimated Energy Costs 2019–20 Retail Tariffs*, draft report prepared for the QCA, February 2019.

Australian Competition and Consumer Commission (ACCC), *Restoring electricity affordability and Australia's competitive advantage*, June 2018.

Australian Energy Market Commission (AEMC), *Advice on Best Practice Retail Price Regulation Methodology*, final report, May 2013.

Australian Energy Market Operator (AEMO), *2018–19 Final Budget and Fees*, June 2018.

Australian Energy Regulator (AER), *Default Market Offer Price*, position paper, November 2018.

Frydenberg, J (Treasurer, Australian Government) & Taylor, A (Minister for Energy, Australian Government), letter to the Australian Energy Regulator, 22 October 2018.

Queensland Government, *Queensland Government response to the Queensland Productivity Commission Electricity Pricing Inquiry*, November 2016.

—*Queensland Budget 2018–19—Budget Strategy and Outlook*, Budget Paper no. 2, 2018.

Reserve Bank of Australia, *Statement on Monetary Policy*, November 2018.

APPENDIX C: RESPONSES TO ADDITIONAL ISSUES RAISED IN SUBMISSIONS RECEIVED

This section outlines responses we have provided to additional issues raised in submissions received, and which have not been otherwise addressed in this final determination.

Stakeholder comment	***Stakeholder***	***QCA response***
The QCA should formalise what BRIG and many others have been reporting. That is, there is no need for demand based tariffs for small business.	BRIG	The question of whether demand based network tariffs are appropriate for small business customers is a matter for Ergon Distribution and the Australian Energy Regulator.
The QCA should recommend implementation of volume based food and fibre tariffs.	BRIG	Under the Queensland Government's delegation, the QCA is required to consider setting notified prices using an N+R approach. The question of whether it is appropriate to develop network tariffs specifically for food and fibre production, which the QCA could then use to develop corresponding retail tariffs, is a matter for Ergon Distribution and the Australian Energy Regulator.
The QCA should recommend promotion of increased competition in the electricity market.	BRIG	The QCA supports competition in electricity markets. However, the implementation of the UTP limits competition in regional Queensland, in particular for residential and small business customers. The UTP is a policy matter for the Queensland Government.
The QCA should recommend continuation of the policy to fund the SFIT from general revenue.	BRIG	This matter is outside the scope of this report, which concerns notified prices for the 2019–20 tariff year. Whether costs for the solar bonus scheme are recovered as a jurisdictional levy or from general revenue is a matter for the Queensland Government, Ergon Distribution and the Australian Energy Regulator.
Consideration should be given to increasing the large customer consumption threshold from 100 MW to 150–200 MW	Canegrowers Isis	This matter is outside the scope of this report, which concerns notified prices for 2019–20. The small business customer threshold is a matter for the Queensland Government, Ergon Distribution and the Australian Energy Regulator.
Tariffs must be developed that recognise the specific requirements of irrigation.	Pioneer Valley Water Co-operative Limited	The question of whether it is appropriate to develop network tariffs specifically for irrigation is a matter for Ergon Distribution and the Australian Energy Regulator.

Stakeholder comment	***Stakeholder***	***QCA response***
The strategy implemented by successive Queensland governments to transition the agricultural sector towards 'cost recovery' for electricity fails to recognise that irrigation schemes were constructed to support the regional economy on the back of increased productivity, and were never intended to recover input costs. The cost recovery model for electricity into the agriculture sector has negatively impacted the regional water market in the Pioneer Valley. The cost recovery model for agriculture should be abandoned.	Pioneer Valley Water Co-operative Limited	The QCA proposes to set notified prices in accordance with the UTP as specified in the Queensland Government's delegation. This approach would result in regional residential, small business and some large business customers paying electricity prices that are generally lower than the costs of supplying these customers. The Queensland Government expects to pay Ergon Retail approximately $465 million in 2018–19 to subsidise regional electricity customers. The question of whether this is an appropriate level of subsidy for the agricultural sector is a policy matter for the Queensland Government.
Separate appropriate and affordable electricity tariffs (16c/kWh to the consumer) must be developed for the agricultural sector.	Pioneer Valley Water Co-operative Limited	Under the Queensland Government's delegation, the QCA must consider setting notified prices using an N+R approach. The question of whether it is appropriate to develop network tariffs specifically for food and fibre production, which the QCA could then use to develop corresponding retail tariffs, is a matter for Ergon Distribution and the Australian Energy Regulator.

APPENDIX D: NETWORK TARIFF STRUCTURES

This appendix provides further information on the decisions in Chapter 3. Energex and Ergon Distribution network tariff structures are compared, and the way tariffs have been adjusted to make them consistent with the UTP is outlined.

Comparison of Energex and Ergon Energy's tariff structures

Table 28 Energex and Ergon Distribution residential and small business customer time-of-use and demand network tariffs

Distributor		***Peak***	***Shoulder***	***Off-peak***
Residential (time-of-use)				
Energex	Usage	4 pm – 8 pm weekdays (weekdays include government specified public holidays)	7 am – 4 pm, 8 pm – 10 pm weekdays (weekdays include government specified public holidays) 7 am – 10 pm weekends	10 pm – 7 am every day
Ergon Distribution (retail tariff 12A)	Usage	3 pm – 9.30 pm any day of the week, summer[a] months only		All other times
Residential (time-of-use demand)				
Energex (introduced on 1 July 2016)	Usage	Flat rate		
	Demand	4 pm – 8 pm workdays (workdays are weekdays but exclude government-specified public holidays)		
Ergon Distribution (retail tariff 14)	Usage	Flat rate		
	Demand	3 pm – 9.30 pm any day of the week, summer[a] months only		3 pm – 9.30 pm any day of the week, non-summer[a] months
Small business (time-of-use)				
Energex	Usage	7 am – 9 pm weekdays (weekdays include government-specified public holidays)		All other times
Ergon Distribution (retail tariff 22A)	Usage	10 am – 8 pm on summer[a] weekdays		All other times

Distributor		***Peak***	***Shoulder***	***Off-peak***
Small business (time-of-use demand)				
Energex (introduced on 1 July 2017)	Usage	Flat rate		
	Demand	9 am – 9 pm workdays (workdays are weekdays but exclude government-specified public holidays)		
Ergon Distribution (retail tariff 24)	Usage	Flat rate		
	Demand	10 am – 8 pm on summer[a] weekdays		10 am – 8 pm weekdays in non-summer[a] months

a. *Summer months are December, January and February.*

Table 29 Energex and Ergon Distribution non–time-of-use network tariffs

Type	***Distributor***	***Fixed***	***Usage/demand***		
Residential (tariff 11)	Energex	c/day	Flat rate in c/kWh		
	Ergon Distribution	c/day	In c/kWh for the first 1,000 kWh/year	In c/kWh for the next 5,000 kWh/year	In c/kWh for usage >6,000 kWh/year
Small business (tariff 20)	Energex	c/day	Flat rate in c/kWh		
	Ergon Distribution	c/day	In c/kWh for the first 1,000 kWh/year	In c/kWh for the next 19,000 kWh/year	In c/kWh for usage >20,000 kWh/year
Small business demand (tariff 41)	Energex	c/day	Flat rate in c/kWh	Demand in $/kVA/month	
	Ergon Distribution	No equivalent network tariff			
Night controlled load (tariff 31)	Energex	n/a	Flat rate in c/kWh		
	Ergon Distribution	c/day	Flat rate in c/kWh		
Controlled load (tariff 33)	Energex	n/a	Flat rate in c/kWh		
	Ergon Distribution	c/day	Flat rate in c/kWh		
Unmetered (tariff 91)	Energex	n/a	Flat rate in c/kWh		
	Ergon Distribution	c/day	Flat rate in c/kWh		

Adjusting Ergon Distribution network tariffs

This section outlines the methodology used (see section 3.2.3) to adjust Ergon Distribution network charges to reflect Energex price levels, while retaining Ergon Distribution tariff structures. This approach is consistent with the approach we adopted in the 2018–19 determination.

Establishing network prices

To calculate network prices that reflect Ergon Distribution tariff structures and Energex price levels, we used information on network charges provided by the distributors[141], and customer usage data provided by Ergon Distribution and Ergon Retail. Using the above-mentioned data, we lowered charges under the relevant Ergon Distribution network tariff[142] to a level where the average customer pays the same as they would under the equivalent Energex network tariff.

This calculated network tariff was then used as the basis of a retail tariff.

Seasonal time-of-use tariffs

Ergon Distribution has seasonal time-of-use network tariffs for residential and small business customers. These network tariffs form the basis of retail tariffs 12A (residential) and 22A (small business). To create retail tariffs that reflect Ergon Distribution network tariff structures, while broadly reflecting Energex price levels, we adjusted all charges under the Ergon Distribution network tariff so that the average customer will pay the same total network cost as they would under the equivalent Energex flat rate network tariff.

The results are shown in tables 30 and 31.

Table 30 Network price options for tariff 12A

	Fixed c/day	*Peak/flat c/kWh*	*Off-peak c/kWh*
Energex 8400	49.000	8.762	–
Ergon Distribution ERTOUT1	133.300	41.421	5.136
QCA-adjusted Ergon Distribution ERTOUT1	42.185	41.421	5.136

Note: Based on data provided by Ergon Distribution and Ergon Retail, average annual usage is taken as 4,508 kWh, with 11.51% peak usage and 88.49% off-peak usage.

Table 31 Network price options for tariff 22A

	Fixed c/day	*Peak/flat c/kWh*	*Off-peak c/kWh*
Energex 8500	66.500	8.663	–
Ergon Distribution EBTOUT1	133.300	46.767	8.898
QCA-adjusted Ergon Distribution EBTOUT1	66.500	38.766	7.376

Note: Based on data provided by Ergon Distribution and Ergon Retail, average annual usage is taken as 15,248 kWh, with 4.1% peak usage and 95.9% off-peak usage.

[141] Energex and Ergon Distribution.
[142] Network tariffs applying to Ergon Distribution's east pricing zone, transmission region one.

Time-of-use demand tariffs

Ergon Distribution has time-of-use demand network tariffs for residential and small business customers. These network tariffs form the basis of retail tariffs 14 (residential) and 24 (small business). To calculate network prices for these retail tariffs, we uniformly reduced all charges of the relevant Ergon Distribution network tariff to equalise the average customer's network bill with the bill they would face on the equivalent Energex flat rate network tariff.

The resulting network prices are shown in tables 32 and 33.

Table 32 Network price options for tariff 14

	Fixed c/day	***Usage c/kWh***	***Peak demand $/kW/month***	***Off-peak demand $/kW/month***
Energex 8400	49.000	8.762	–	–
Ergon Distribution ERTOUDCT1	8.300	2.673	80.078	11.500
QCA-adjusted Ergon Distribution ERTOUDCT1	5.473	1.763	52.802	7.583

Note: Based on data provided by Ergon Distribution and Ergon Retail, average annual usage is taken as 4,508 kWh with a peak demand of 1.42 kW per month and an off-peak demand of 3.66 kW per month.

Table 33 Network price options for tariff 24

	Fixed c/day	***Usage c/kWh***	***Peak demand $/kW/month***	***Off-peak demand $/kW/month***
Energex 8500	66.500	8.663	–	–
Ergon Distribution EBTOUDCT1	8.300	3.329	99.515	10.000
QCA-adjusted Ergon Distribution EBTOUDCT1	5.728	2.298	68.678	6.901

Note: Based on data provided by Ergon Distribution and Ergon Retail, average annual usage is taken as 15,248 kWh with a peak demand of 3.22 kW per month with an off-peak demand of 8.523 kW per month.

Non–time-of-use tariffs

As discussed in Chapter 3, we examined the impact of using Ergon Distribution's inclining block tariff structure as the basis for flat-rate retail tariffs 11 (residential) and 20 (small business). For the purposes of this assessment, we calculated network prices by uniformly reducing all charges of the relevant Ergon Distribution network tariff to equalise the total network revenue recovered by Ergon Distribution under an inclining block tariff with the network revenue it would have otherwise recovered under an Energex flat rate tariff (see Tables 34 and 35). Network prices calculated using this approach are consistent with the UTP.

The impact on customers are shown in Figures 22 and 23.

Table 34 Network price options for tariff 11

	Fixed c/day	Usage c/kWh		
		Flat/first block [a]	*Second block* [b]	*Third block* [c]
Energex 8400	49.000	8.762	–	–
Ergon Distribution ERIBT1	133.300	3.172	6.528	10.181
QCA-adjusted Ergon Distribution ERIBT1[d]	99.347	2.364	4.865	7.588

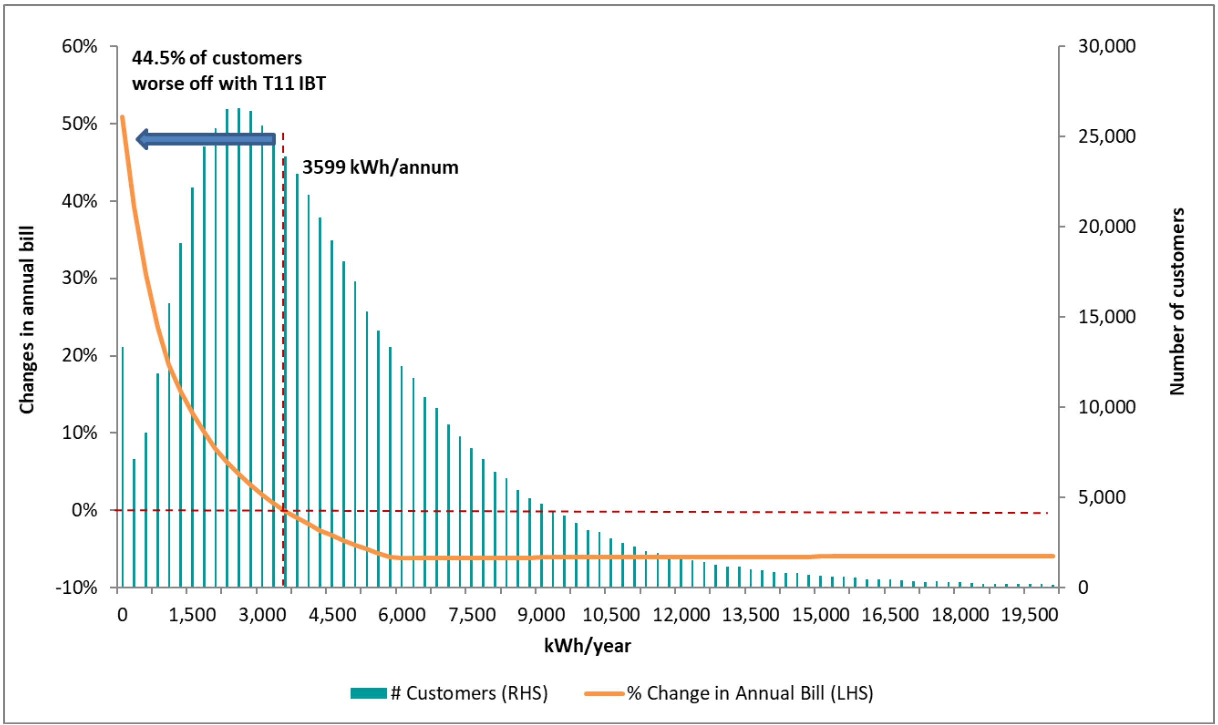
a *Usage charge applies to all usage under an Energex network tariff (row 1). Usage charge applies to the average usage of less than 2.74 kWh per day under an Ergon Distribution network tariff (rows 2 and 3).*

b *Usage charge applies to the average usage greater than 2.74 kWh per day and less than 16.43 kWh per day under an Ergon Distribution network tariff (rows 2 and 3).*

c *Usage charge applies to the average usage above 16.43 kWh per day under an Ergon Distribution network tariff (rows 2 and 3).*

d *Network prices were adjusted in a manner such that the relativities between the different pricing components within the tariff are preserved.*

Figure 22 Impact on tariff 11 customers adopting Ergon Distribution inclining block tariff structure



a *IBT—inclining block tariffs.*

b *RHS—right hand side. LHS—left hand side.*

c *44.5% of customers (consuming below 3599 kWh/annum) on average will be worse off moving from a residential flat tariff (tariff 11) to Ergon Distribution inclining block tariff structure.*

Table 35 Network price options for tariff 20

	Fixed c/day	*Usage c/kWh*		
		Flat/first block [a]	*Second block* [b]	*Third block* [c]
Energex 8500	66.500	8.663	–	–
Ergon Distribution EBIBT1	133.300	3.528	9.077	13.122
QCA-adjusted Ergon Distribution EBIBT1[d]	101.012	2.674	6.879	9.944

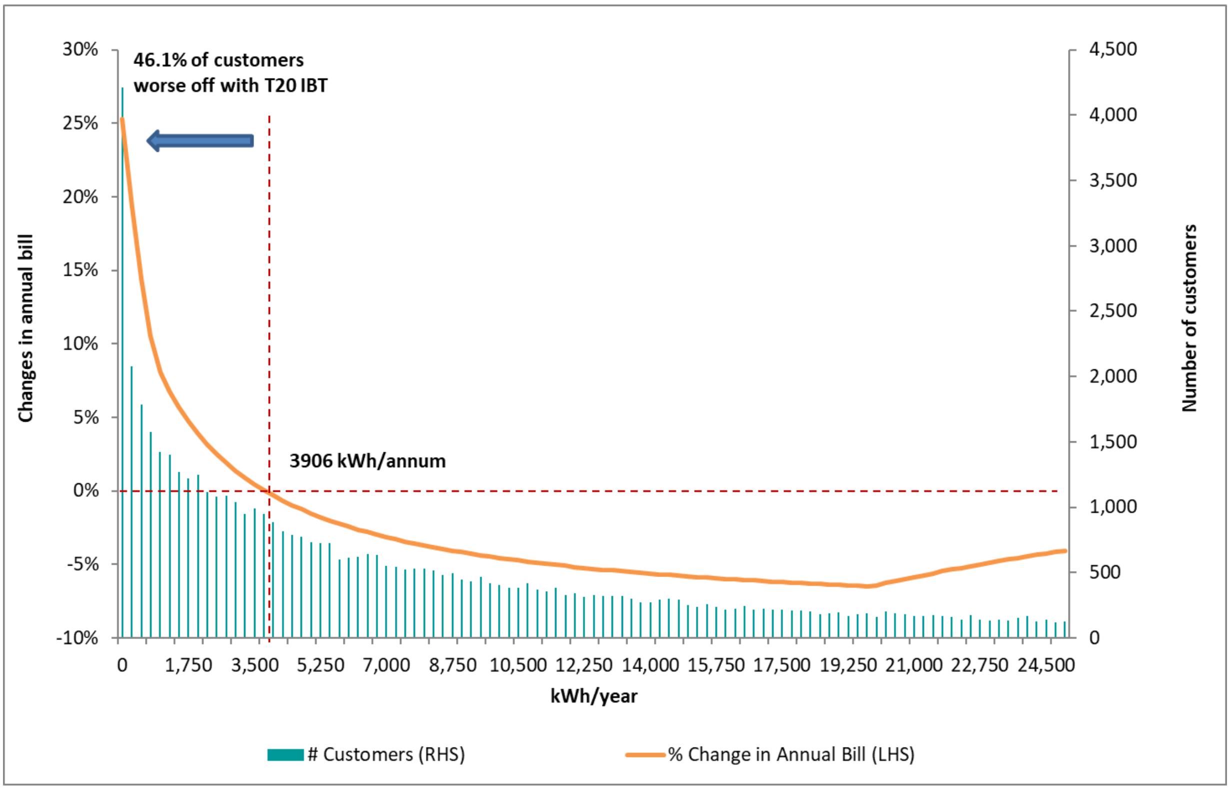
a *Usage charge applies to all usage under an Energex network tariff (row 1). Usage charge applies to the average usage of less than 2.74 kWh per day under an Ergon Distribution network tariff (rows 2 and 3).*

b *Usage charge applies to the average usage greater than 2.74 kWh per day and less than 54.76 kWh per day under an Ergon Distribution network tariff (rows 2 and 3).*

c *Usage charge applies to the average usage above 54.76 kWh per day under an Ergon Distribution network tariff (rows 2 and 3).*

d *Network prices were adjusted in a manner such that the relativities between the different pricing components within the tariff are preserved.*

Figure 23 Impact on tariff 20 customers adopting Ergon Distribution inclining block tariff structure



a *IBT—inclining block tariffs.*

b *RHS—right hand side. LHS—left hand side.*

c *46.1% of customers (consuming below 3906 kWh/annum) on average will be worse off moving from a small business flat tariff (tariff 20) to Ergon Distribution inclining block tariff structure.*

APPENDIX E: TRANSITIONAL AND OBSOLETE TARIFFS—CUSTOMER IMPACTS

Our draft decision on the arrangements for customers on transitional and obsolete retail tariffs is set out in Chapter 7. In making that decision we used data provided by Ergon Retail.

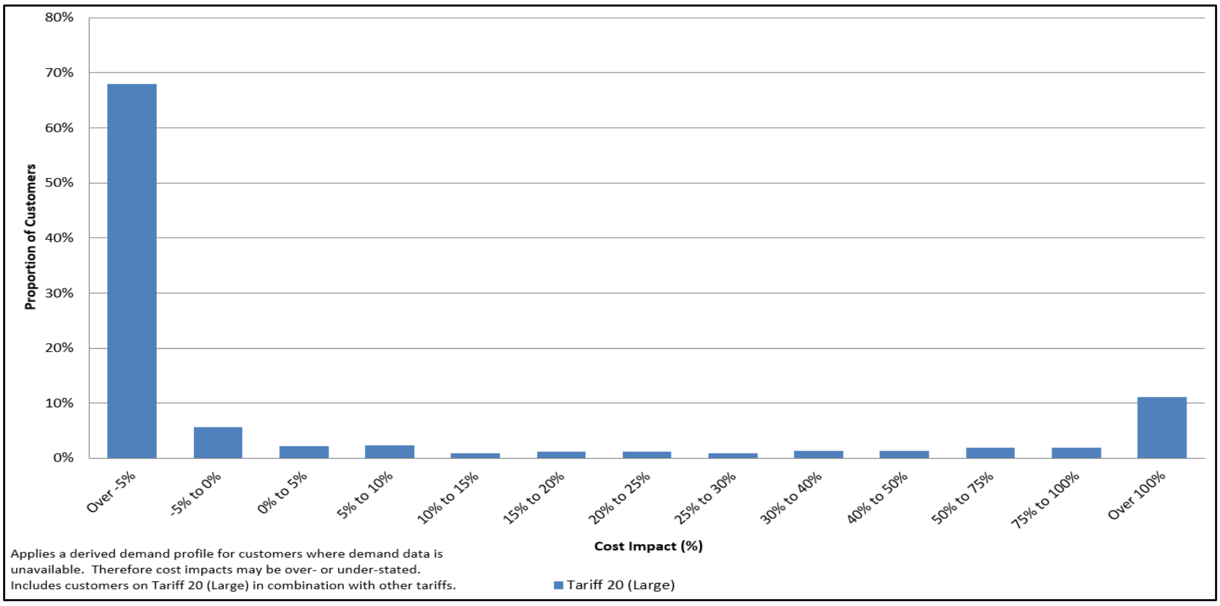
This appendix contains the analysis of bill impacts for customers moving from a 2018–19 transitional or obsolete tariff to an alternative 2018–19 standard business tariff.

The customer impacts are calculated on an individual tariff basis. As some customers are supplied under multiple tariffs, the overall impact to an individual customer may be a combination of the impacts shown below.

Tariff 20 (large)

Transitional tariff 20 (large) aligns with tariffs 44 to 53, which are based on Ergon Energy network tariffs and charges. Figure 24 shows the likely impacts for large business customers moving from this transitional tariff to the most appropriate standard large business customer tariffs.

Figure 24 Change in electricity bills for business customers on tariff 20 (large) moving to large customer standard business tariffs

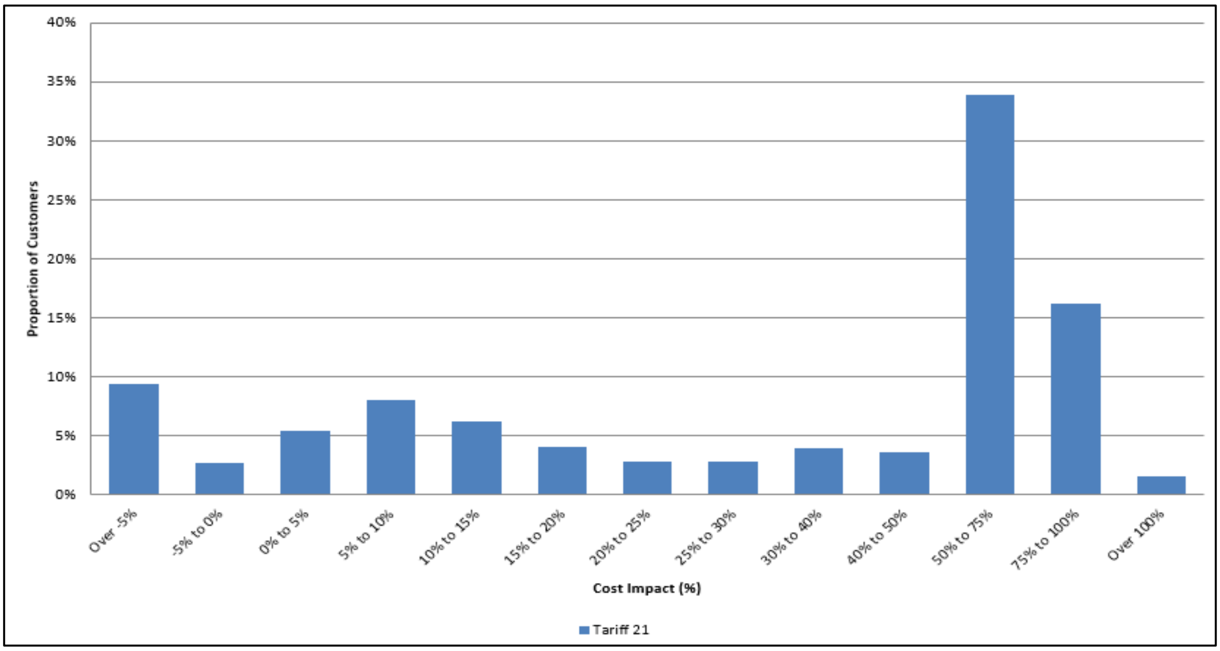


Source: Ergon Retail.

Tariff 21

Tariff 21 is a declining block tariff that aligns with tariff 20 for small business customers. Figures 25 to 27 show the distribution of potential impacts for existing customers moving to standard business tariffs.

Figure 25 Change in electricity bills for small business customers on tariff 21 moving to tariff 20

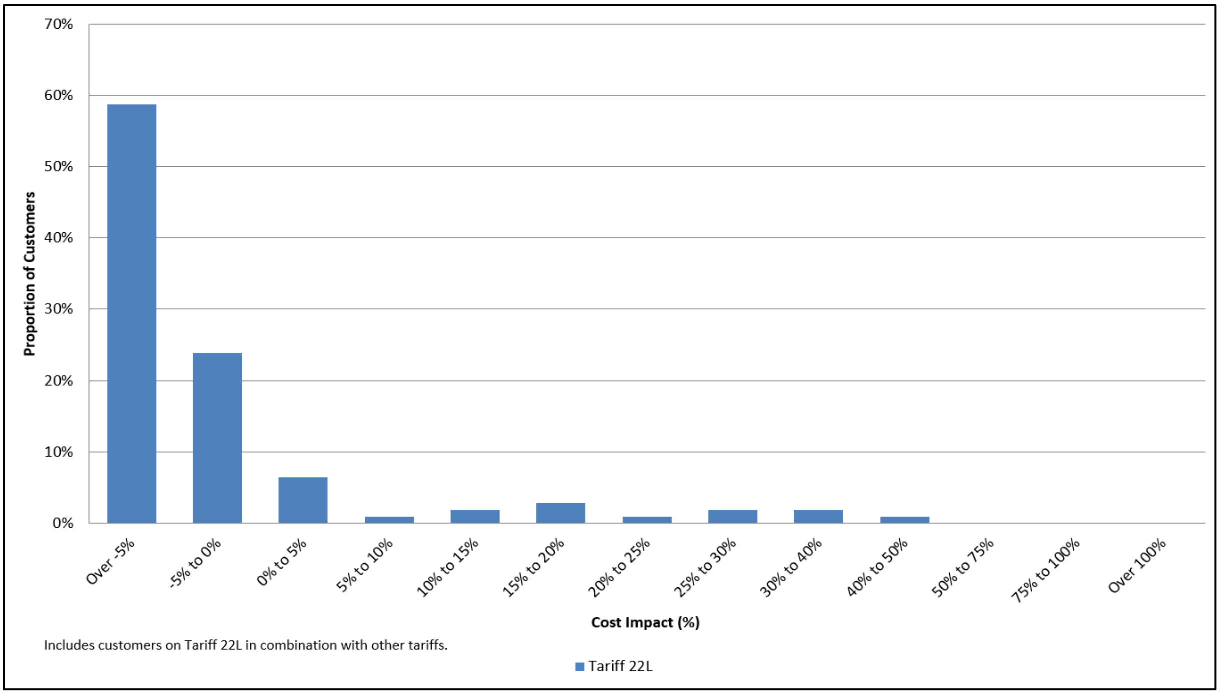


Source: Ergon Retail.

Tariff 22 (small and large)

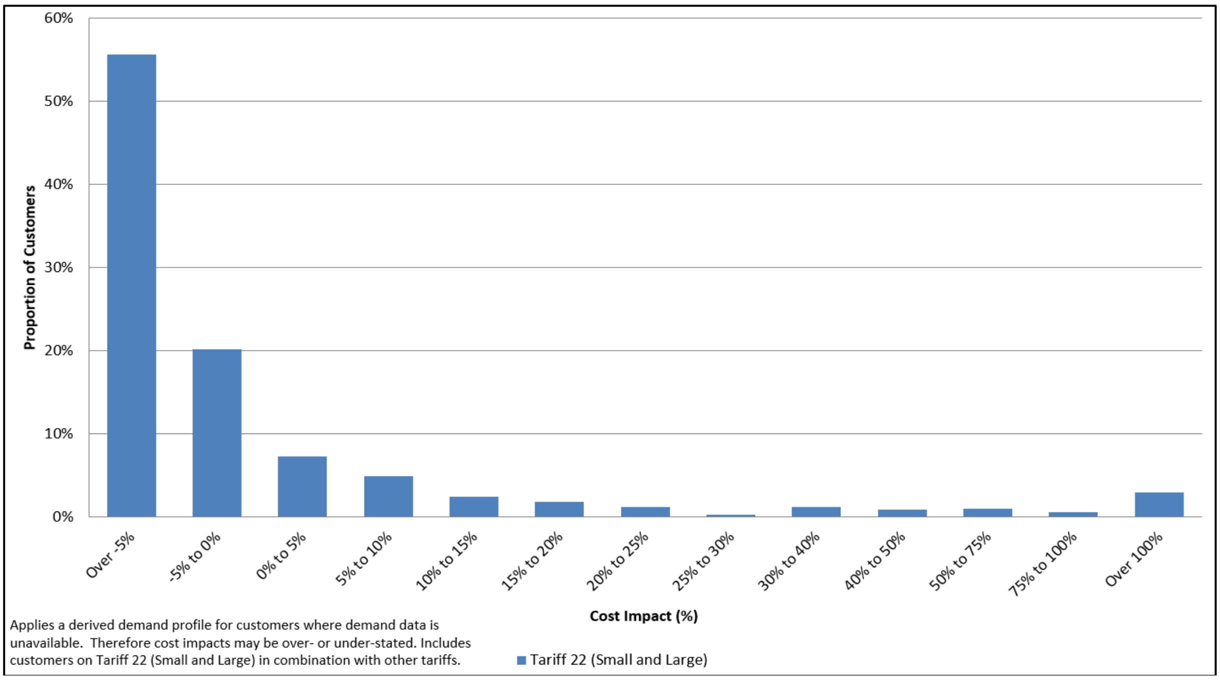
Transitional tariff 22 (small and large) aligns with tariffs 20 for small business customers and tariffs 44 to 53 for large business customers, which are based on Ergon Energy network tariffs and charges. Figures 26 to 27 show the likely impacts for business customers moving from these transitional tariffs to the most appropriate standard business customer tariffs.

Figure 26 Change in electricity bills for large business customers on tariff 22 (small and large) moving to small customer standard tariffs



Source: Ergon Retail.

Figure 27 Change in electricity bills for large business customers on tariff 22 (small and large) moving to large customer standard tariffs

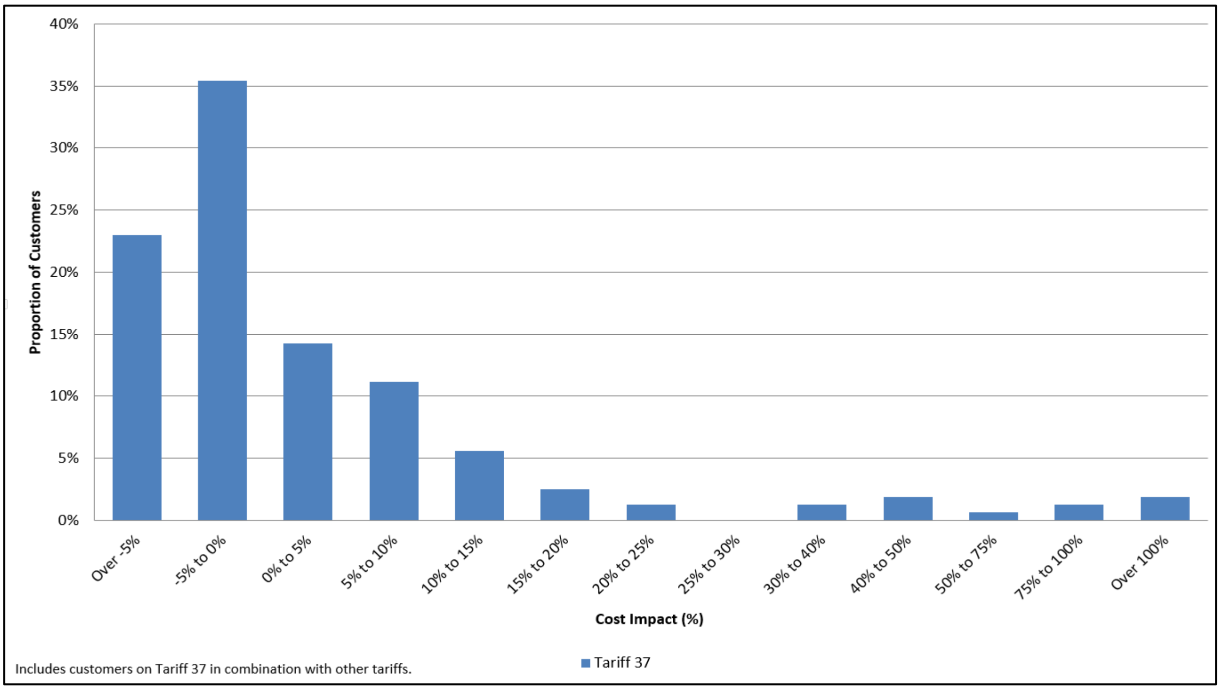


Source: Ergon Retail.

Tariff 37

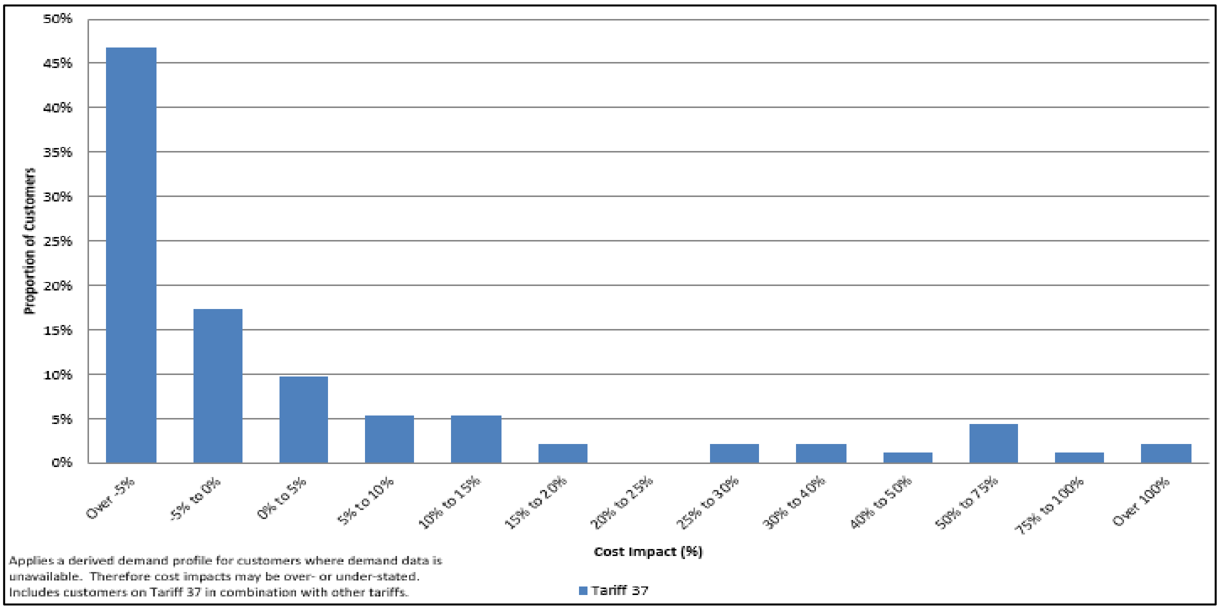
Tariff 37 is a business time-of-use tariff that aligns with tariffs 20 or 22A for small business customers and one of tariffs 44 to 53 for large business customers. Figures 28 and 29 show the distribution of potential impacts for existing customers moving to these standard business tariffs.

Figure 28 Change in electricity bills for small business customers on tariff 37 moving to tariff 20



Source: Ergon Retail.

Figure 29 Change in electricity bills for large business customers on tariff 37 moving to large customer standard business tariffs

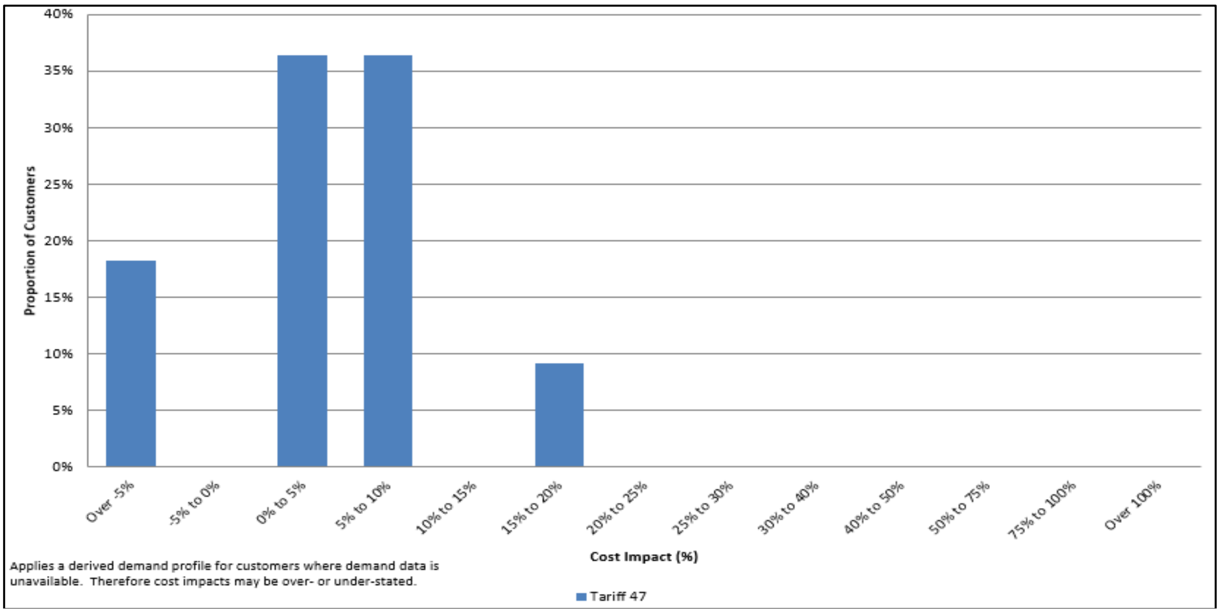


Source: Ergon Retail.

Tariffs 47 and 48

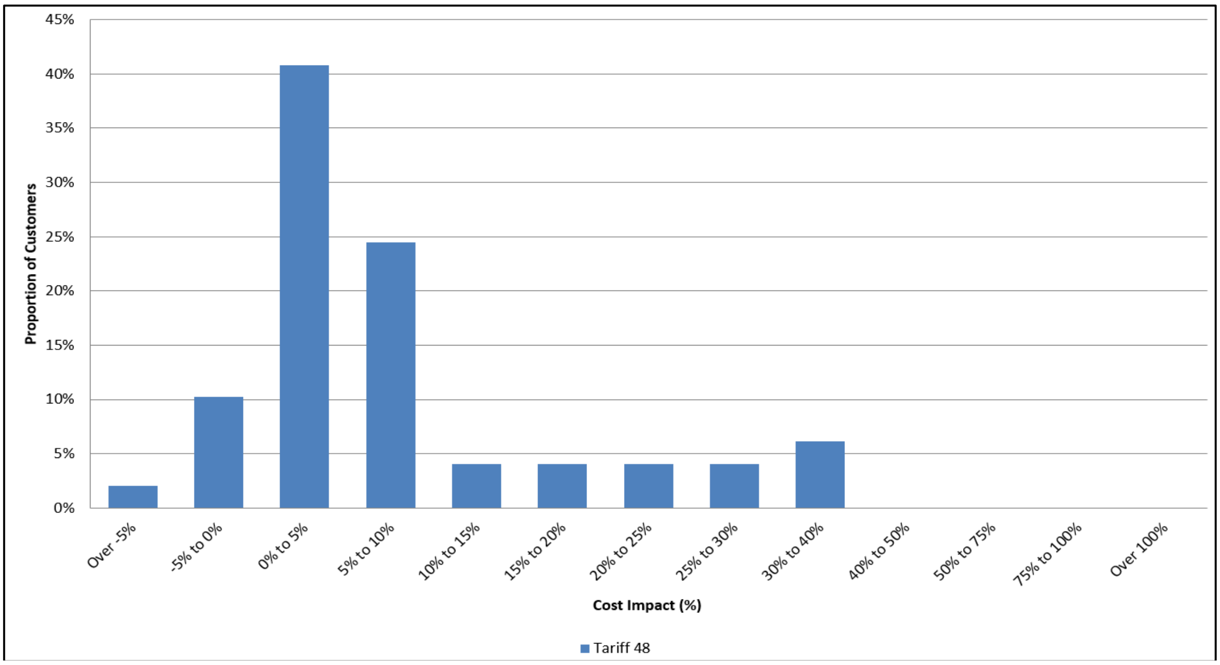
Transitional tariffs 47 and 48 (both very large) align with tariffs 51A–D, 52A–C and 53, which are based on Ergon Energy network tariffs and charges. Figures 30 and 31 show the likely impacts for large business customers moving from transitional tariffs 47 and 48 to the most appropriate standard business tariffs.

Figure 30 Estimated bill impact for customers moving from tariff 47 to standard business tariffs



Source: Ergon Retail

Figure 31 Estimated bill impact for customers moving from tariff 48 to standard business tariffs



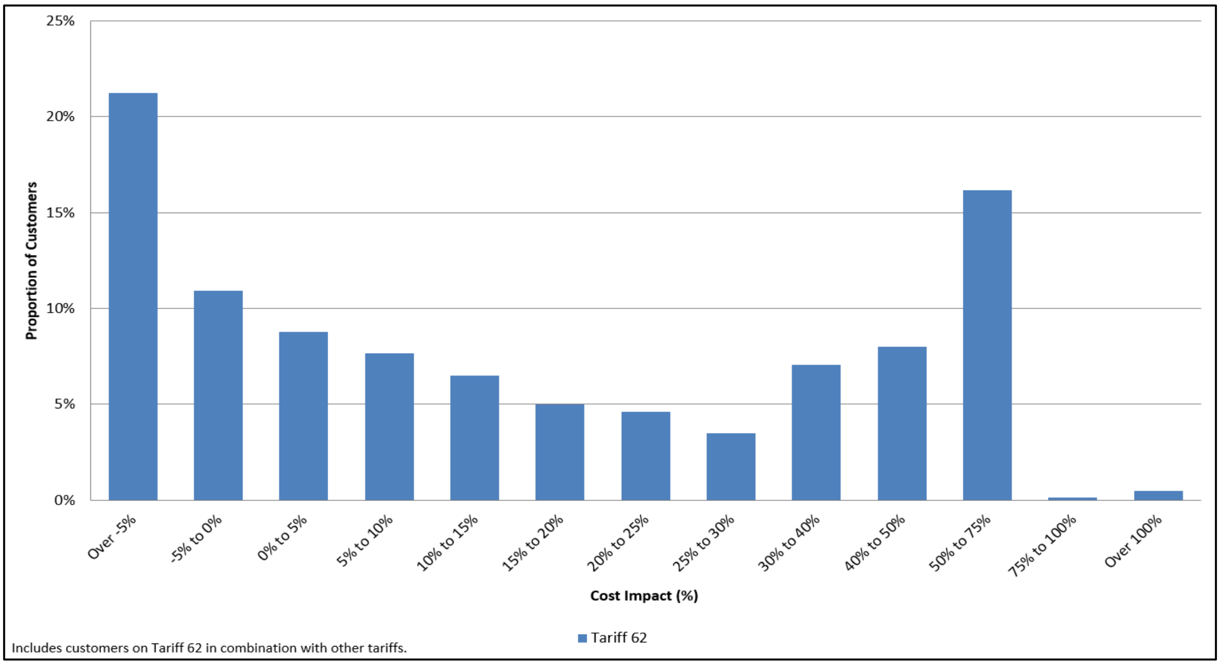
Source: Ergon Retail

Tariffs 62 and 65

Tariffs 62 and 65 are time-of-use tariffs for farming and irrigation customers. These tariffs align with tariffs 20 or 22A for small business customers and tariffs 44 and 45 for large business customers. Figures 32 to

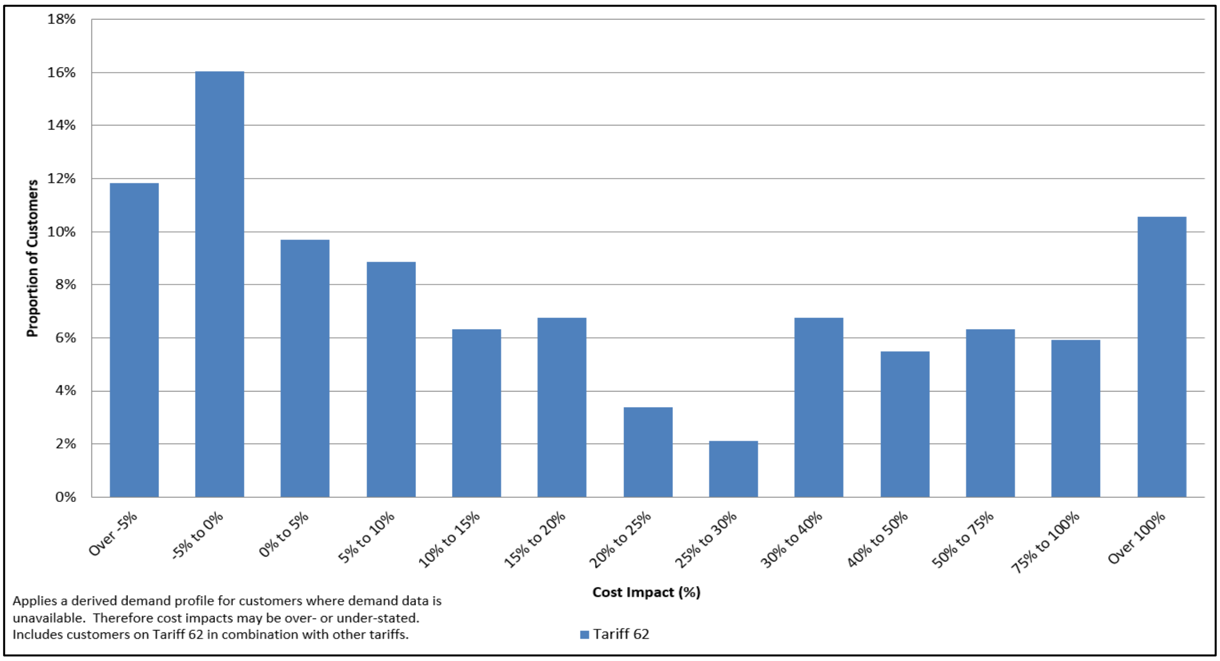
35 show the distribution of potential impacts for existing customers moving to these standard business tariffs.

Figure 32 Change in electricity bills for small business customers on tariff 62 moving to tariff 20



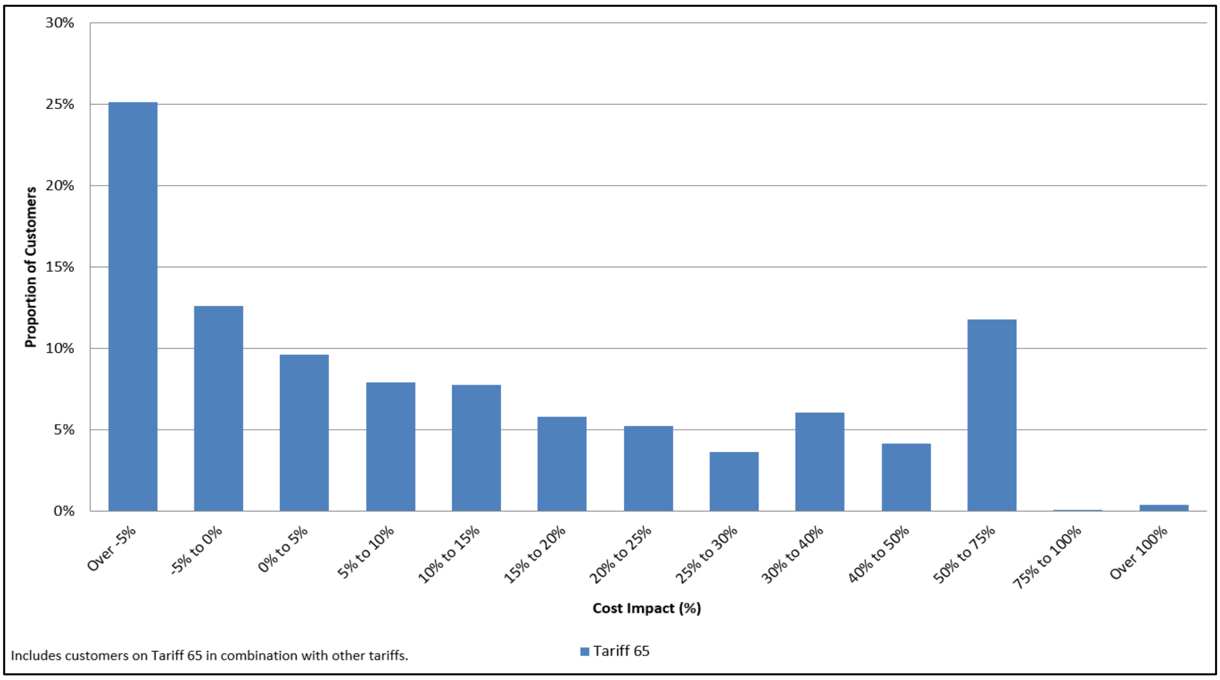
Source: Ergon Retail.

Figure 33 Change in electricity bills for large business customers on tariff 62 moving to large customer standard business tariffs



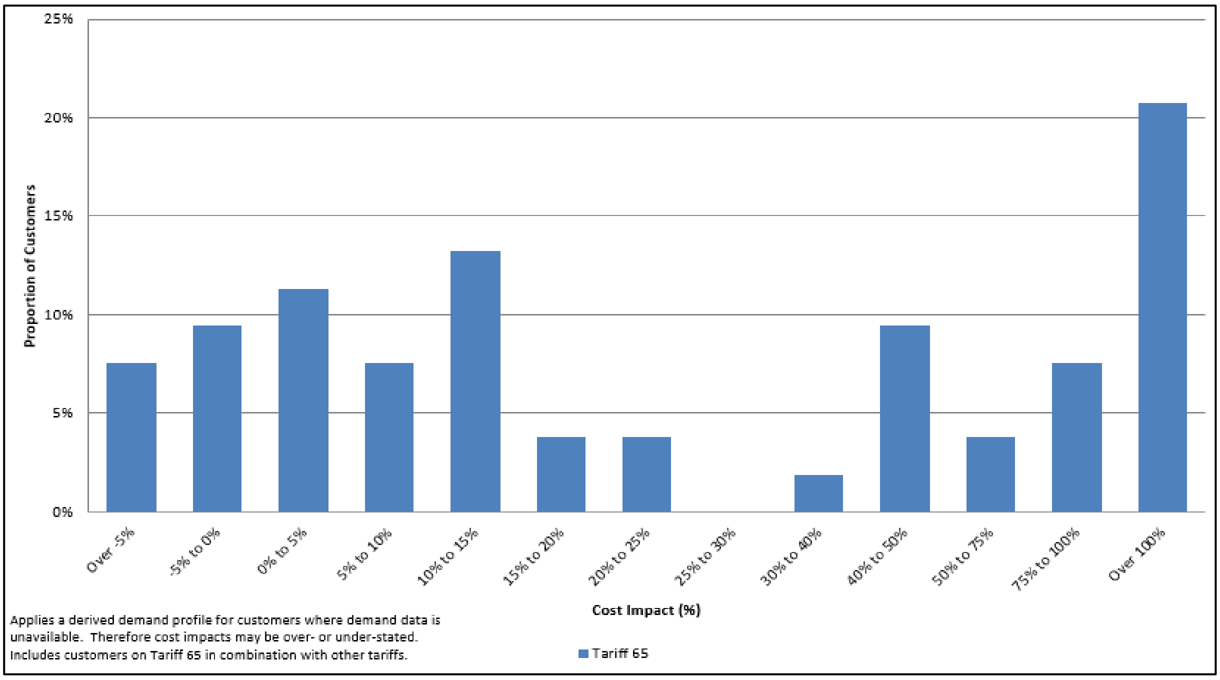
Source: Ergon Retail.

Figure 34 Change in electricity bills for small business customers on tariff 65 moving to tariff 20



Source: Ergon Retail.

Figure 35 Change in electricity bills for large business customers on tariff 65 moving to large customer standard business tariffs

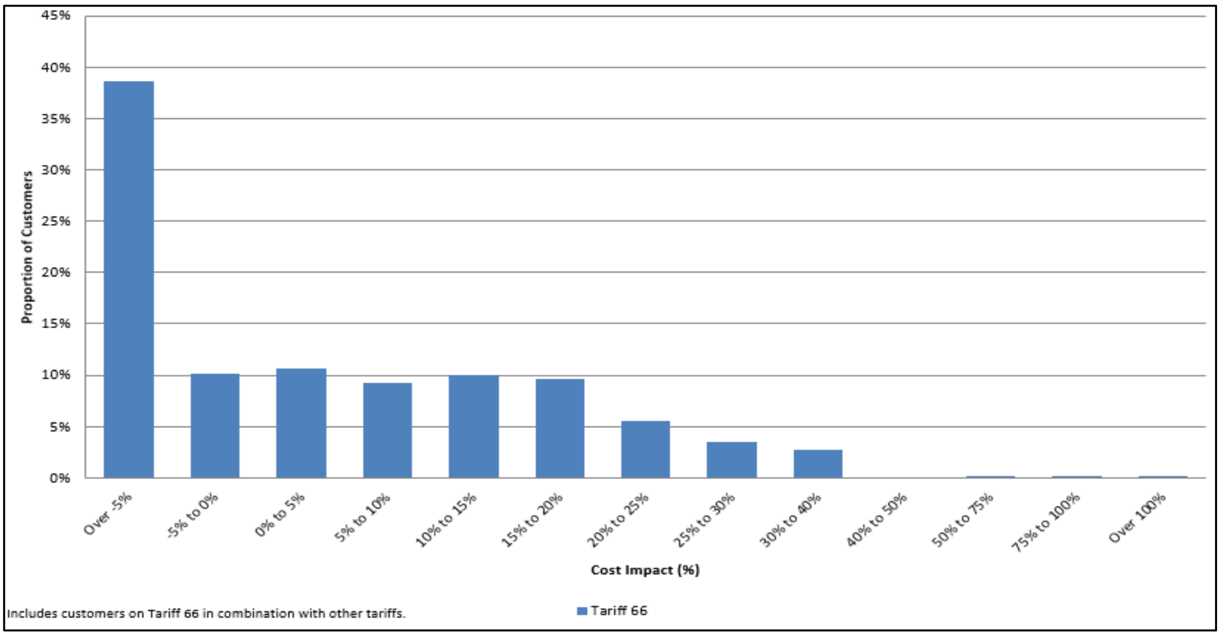


Source: Ergon Retail.

Tariff 66

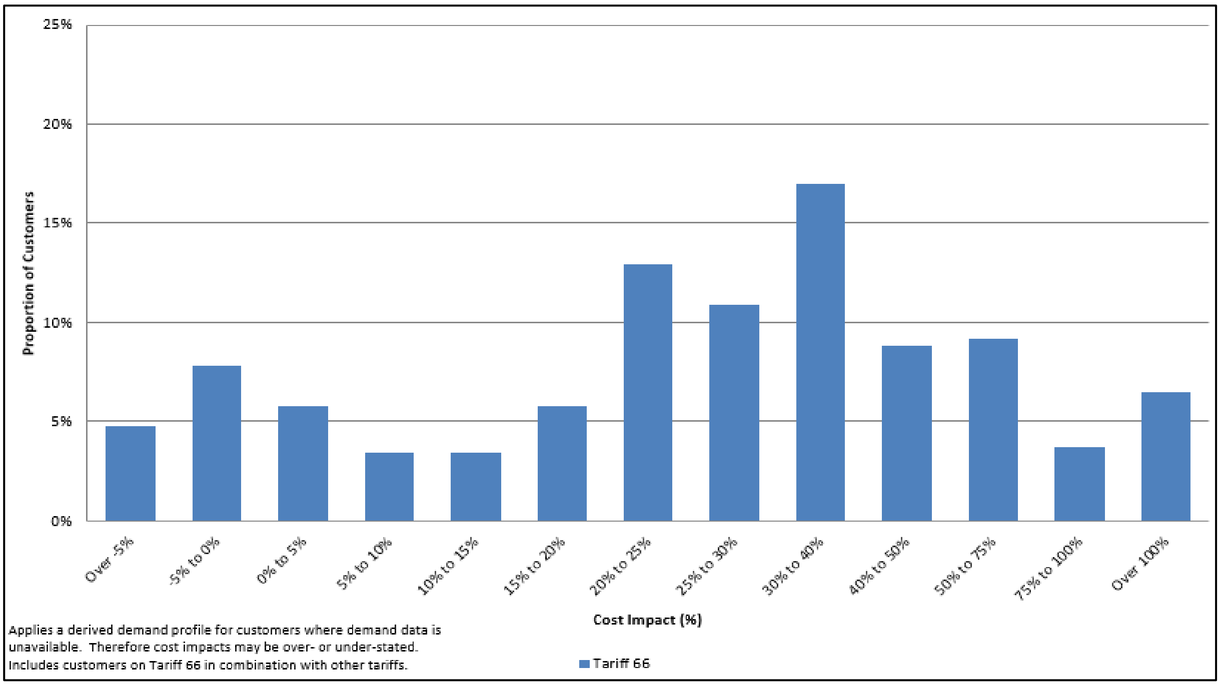
Tariff 66 is a flat-rate tariff for irrigation customers. This tariff aligns with tariffs 20 or 22A for small business customers and tariffs 44 and 45 for large business customers. Figures 36 and 37 show the distribution of potential impacts for existing customers moving to these standard business tariffs.

Figure 36 Change in electricity bills for small business customers on tariff 66 moving to tariff 20



Source: Ergon Retail.

Figure 37 Change in electricity bills for large business customers on tariff 66 moving to large customer standard business tariffs



Source: Ergon Retail.

APPENDIX F: GAZETTE NOTICE

This is the draft gazette notice for 2019–20, which reflects the QCA's draft determination. Matters in part 1 of the gazette notice have been supplied by the Queensland Government, as they reflect government policy decisions.

Queensland Government Gazette

Electricity Act 1994

RETAIL ELECTRICITY PRICES FOR STANDARD CONTRACT CUSTOMERS

This Gazette notice replaces the Retail Electricity Prices for Standard Contact Customers notice dated 26 July 2018, by Anthony Lynham MP, Minister for Natural Resources, Mines and Energy.

The notified prices are the prices decided under section 90(1) of the *Electricity Act 1994* (the Electricity Act).

A retailer must charge its Standard Contract Customers, as defined in the Electricity Act, the notified prices subject to the provisions of sections 91, 91A and 91AA of the Electricity Act and section 22A, Division 12A of Part 2 of the National Energy Retail Law (Queensland) (the NERL (Qld)).

Pursuant to the Certificate of Delegation from the Minister for Natural Resources, Mines and Energy (dated 17 December 2018) and sections 90 and 90AB of the Electricity Act, I hereby state that the Queensland Competition Authority decided that, on and from 1 July 2019, the notified prices are the applicable prices set out in the attached Tariff Schedule.

As required by section 90AB(4) of the Electricity Act, the notified prices are exclusive of the goods and services tax ('GST') payable under the *A New Tax System (Goods and Services Tax) Act 1999* (Cth) (the GST Act).

Dated this TBC day of May 2019.

Flavio Menezes, Chair
Queensland Competition Authority

TARIFF SCHEDULE

Part 1 — Application

A) APPLICATION OF THIS SCHEDULE – GENERAL

This Tariff Schedule applies to all Standard Contract Customers in Queensland other than those in the Energex distribution area.

Definitions of customers and their types are those set out in the Electricity Act and the NERL(Qld). Unless otherwise defined, the terminology used in this Tariff Schedule is intended to be consistent with the energy laws.

Where a notified price has been set for a distribution entity *alternate control service*, a retailer can only charge the customer for that service at the notified price.

B) APPLICATION OF TARIFFS

General

Distribution entities may have specific eligibility criteria in addition to retail tariff eligibility requirements set out in the Tariff Schedule, e.g. the types of loads and how they are connected to interruptible supply tariffs. Retailers will advise customers of any applicable distribution entity requirements upon tariff assignment or customer request.

Additional customer descriptions:

- *Farming* is the undertaking of agricultural or associated business activities for the primary purpose of profit. The primary use of electricity supplied under a farming tariff should be for farming.
- *Irrigation* is the undertaking of pumping water for farming. The primary use of electricity supplied under an irrigation tariff should be for irrigation.
- A *Connection Asset Customer (CAC)* is a large business customer whose required capacity generally exceeds 1500 kVA and annual energy usage generally exceeds 4GWh as classified by the distribution entity.
- An *Individually Calculated Customer (ICC)* is a large business customer whose annual energy usage generally exceeds 40GWh as classified by the distribution entity.

CAC or ICC customers can only access tariffs where specifically stated in the tariff description, or as agreed by the retailer.

MI means the unique identification number applicable to the point at which a premises is connected to a distribution entity's network. For premises connected to the National Electricity Market this is the National Metering Identifier (NMI), and for other premises is the unique identifier allocated by the distribution entity.

An *MI exclusive* tariff cannot be used in conjunction with any other tariff at that MI. All large customer continuous supply tariffs are MI exclusive tariffs unless otherwise stated.

A *primary* tariff is the tariff that reflects the principal purpose of use of electricity at the premises or the majority of the load, and is capable of existing by itself against a MI.

Small business customers can access primary residential tariffs providing the nature of all use on the tariff is consistent with the tariff requirements (refer below for *concessional application* of primary residential tariffs), and is in conjunction with a primary business tariff (Tariff 20, 21, 22, 22A, 24, 41, 62, 65 or 66) at the same MI.

Primary residential tariffs are also applicable to electricity used in separately metered common sections of residential premises consisting of more than one living unit, but cannot be used in conjunction with another primary residential tariff at the same MI.

A *secondary* tariff is any tariff that is not a primary tariff, and can be accessed only when it is in conjunction with a primary tariff at the same MI unless otherwise stated.

A *seasonal* tariff is any tariff for which charges vary depending on the month the charge applies. Seasonal tariffs can also include time-of –use based charges.

A *time-of-use* tariff is any tariff for which charges vary depending on the time of day.

An *obsolete* tariff can only be accessed by customers who:

(a) are on the tariff at the date it becomes obsolete; and

(b) continuously take supply under it.

The *scheduled phase-out date* is the date an obsolete tariff will be discontinued. Customers on obsolete tariffs may opt to transfer at any time to applicable standard tariffs. Customers on an obsolete tariff on its scheduled phase-out date whom have not notified their retailer of their preferred applicable standard tariff, will be transferred to an applicable standard tariff at the discretion of the retailer upon the tariff being discontinued.

Any reference in this Tariff Schedule to a time is a reference to Eastern Standard Time.

Weekdays mean Monday to Friday including public holidays.

Summer is the months of December to February inclusive.

Summer peak window is from 4:00pm to 9:00pm on any day within months November to March.

A *daily supply charge* is a fixed amount charged to cover the costs of maintaining electricity supply to a premises, including the costs associated with the provision of equipment (excluding metering and associated services) and general administration. Retailers may use different terms for this charge, for example: Service Charge, Service Fee, Service to Property Charge etc.

A *minimum daily payment* only applies when usage charges for the billing period are less than the total of the minimum daily payment multiplied by the number of days in the billing period. Where the total minimum daily payment is charged, usage charges will not apply.

A connection charge reflects the value of the customer's dedicated connection assets and whether these assets were paid for upfront by the customer. The number of connection units allocated to an MI is as advised by the distribution entity.

Demand is the average rate of use of electricity over a 30-minute period as recorded in kilowatts (kW) on the associated metering, or as calculated in kilovolt-amperes (kVA) using data recorded on the associated metering. No adjustment to import demand is made for export to the distribution network.

Maximum demand is highest demand during the charging period of the particular tariff as identified by the tariff description. Unless otherwise stated, the maximum demand is the value on which demand charges are based.

A *demand threshold* is the demand value below which demand charges do not apply for billing purposes. Where a demand threshold applies, the chargeable demand is the greater of the maximum demand less the demand threshold, or zero.

Authorised demand is the maximum demand permitted to be imported from, or exported to the network, and is specific to each MI. The value is generally established by agreement between the customer and distribution entity.

Capacity is a demand-based measure of the network supply capability reserved for a customer. Unless otherwise stated, the capacity charge is the greater of the authorised demand, or actual maximum demand.

Reactive demand is the average rate of use of electricity over a 30-minute period as recorded in kilovolt-amperes reactive (kvar) on the associated metering.

Permissible reactive demand for an MI is determined by applying its compliant power factor (as set out by the National Energy Rules) to its authorised demand.

Excess reactive demand (also known as excess reactive power) charges are the greater of the reactive demand occurring at the time of the maximum demand, less the permissible reactive demand, or zero.

Bus customers are those taking supply via direct connection to the distribution entity's zone substation or similar as advised by the distribution entity.

Line customers are those taking supply via direct connection to the distribution entity's high voltage electrical wires, cabling, or similar as advised by the distribution entity.

Standard tariffs
Tariff 15
Customers must nominate the Band to be applied to the customer's account. Customers cannot change to a lower Band less than one year from the application of the nominated Band to the customer's account without the retailer's agreement unless expressly allowed or permitted by energy law. Customers can switch to a higher Band at any time.

Each band sets the amount of electricity that can be used each day during the summer peak window without incurring top-up charges.

Usage charges apply to all metered use in addition to the monthly band charges, including usage in the summer peak window.

If any daily amount of electricity used during the summer peak window exceeds the allowance included in the chosen band, the top-up charge applies. If applicable, the top-up charge applies to the highest daily exceedance in the month it occurs.

Customers must provide explicit informed consent to monthly billing in order to access this tariff.

Interruptible supply tariffs
General:
These tariffs are applicable when electricity supply is:

(a) connected to approved apparatus (e.g. pool pump) via a socket-outlet as approved by the retailer; or

(b) permanently connected to approved apparatus (e.g. electric hot water system) as approved by the retailer (but not applicable if provision has been made to supply the apparatus under a different tariff during the supply interruption period).

The retailer will arrange the provision of load control equipment on a similar basis to provision of the required revenue metering.

Tariff 31
In addition to the general requirements above, this tariff is also applicable when electricity supply is permanently connected to approved specified parts of apparatus (e.g. hot water system booster heating unit), as approved by the retailer, but not applicable if provision has been made to supply the specified part under a different tariff during the supply interruption period except as agreed by the retailer (e.g. for a one-shot booster for a solar hot water system), in which case it must be metered under and charged at the primary tariff of the premises concerned, or if more than one primary tariff exists, the tariff applicable to general power usage at the premises.

Tariff 33
In addition to the general requirements above, this tariff is also applicable as a primary tariff at the absolute discretion of the retailer.

This tariff shall not apply in conjunction with Tariff 24.

Obsolete tariffs
Tariff 20 (large)
This tariff cannot be accessed by small customers.

Tariff 21
This tariff shall not apply in conjunction with Tariff 20, 22, 22A, 24 or 62.

Tariff 37
This tariff is applicable when electricity supply is permanently connected to approved apparatus (e.g. electric storage hot water system, apparatus for the production of steam) as approved by the retailer.

Tariff 47
Supply under this tariff will be at a standard high voltage, the level of which shall be prescribed by the distribution entity. Credits for high voltage supply are not applicable to this tariff.

Tariff 62
This tariff shall not apply in conjunction with Tariff 20, 21, 22, 22A or 24.

Tariff 65
The *daily pricing period* is a fixed 12-hour period as agreed between the retailer and the customer from the range 7.00am to 7.00pm; 7.30am to 7.30pm; or 8.00am to 8.00pm Monday to Sunday inclusive.

No alteration to the agreed daily pricing period is permitted until a period of twelve months has elapsed from the previous selection.

Tariff 66
The annual fixed charge is determined by the larger of the connected motor capacity used for irrigation pumping, or 7.5 kW.

Any customer taking supply under this tariff who requests a temporary disconnection will not be reconnected unless an amount equivalent to the fixed charge that would have otherwise applied corresponding to the period of disconnection, has been paid.

Unmetered supply tariffs

Tariff 71

Street lighting customers as defined in Queensland legislative instruments, are State or local government agencies for street lighting loads.

Street lights are deemed to illuminate the following types of roads:

- *Local government* controlled roads comprising land that is:
  (a) dedicated to public use as a road; or
  (b) developed for (or has as one of its main uses) the driving or riding of motor vehicles and is open to, or used by, the public; or
  (c) a footpath or bicycle path; or
  (d) a bridge, culvert, ford, tunnel or viaduct,

  and excludes State-controlled roads and public thoroughfare easements; and
- *State-controlled roads* declared as such under the *Transport Infrastructure Act 1994* (Qld).

All usage will be determined in accordance with the metrology procedure.

Tariff 91

It is available only to customers with small loads other than street lights as approved by the retailer, and applies where:

(a) the load pattern is predictable;

(b) for the purposes of settlements, the load pattern (including load and on/off time) can be reasonably calculated by a relevant method set out in the metrology procedure; and

(c) it would not be cost effective to meter the connection point taking into account:
  (i) the small magnitude of the load;
  (ii) the connection arrangements; and
  (iii) the geographical and physical location.

Charges are based on usage determined by the retailer.

Charges for installation, maintenance and removal of supply to an unmetered installation may apply in addition to the charge for electricity supplied. These charges are unregulated.

Tariff changes

Customers previously supplied under tariffs which have been discontinued or redesignated (whether by number, letter or name) will be supplied under other tariffs appropriate to their installations.

Customers on seasonal time-of-use tariffs cannot change to another tariff less than one year from the application of the tariff to the customer's account without the retailer's agreement unless expressly allowed or permitted by energy law.

Prorating of charges on bills

Where appropriate, charges on bills will be calculated on a pro rata basis having regard to the number of days in the billing cycle that supply was connected as expressly allowed or permitted by energy law. Retailers can advise customers of which charges on their bills are subject to prorating, and the methodology used.

Supply voltage

Tariffs in this Schedule can only be accessed by customers taking supply at *low voltage* as set out in the *Electricity Regulation 2006* unless it is a designated high voltage tariff, or otherwise agreed with the retailer.

Where supply is given and metered at high voltage and the tariff applied is not a designated high voltage tariff, after billing the energy and demand components of the tariff a credit will be allowed of:

- 5 percent of the calculated tariff charge where supply is given at voltages of 11kV to 33kV; or
- 8 percent of the calculated tariff charge where supply is given at voltages of 66kV and above,

provided that the calculated tariff charge after application of the credit is not less than the Minimum Payment or other minimum charge calculated by applying the provisions of the applied tariff.

Metering

General

Revenue metering is metering used for billing purposes. Appropriate revenue metering must be in place for each tariff at a MI.

A *type 4A* meter is a type 4 advanced digital meter which has the remote communications functions disabled.

The *metrology procedure* is issued by the Australian Energy Market Operator as varied by the Electricity Distribution Network Code.

Charges for large customer metering services regulated by the Australian Energy Regulator and levied by the distribution entity are not included in notified prices. These will be applied to large customers with metering other than types 1 to 4, in addition to the applicable notified prices contained in this Tariff Schedule.

Where the customer refuses telecommunications and a type 4A meter is installed at the customer's explicit voluntary choice, the type 4A surcharge applies.

If a retailer has received an upfront payment for supply and installation of metering at an MI, while the metering remains installed the retailer shall not charge the customer the capital charge set out in Part 5 of this Schedule, unless:

- any replaced metering is type 5 or type 6; and
- replacement is completed on a customer initiated request; and
- the distribution entity as owner of the replaced meter continues to charge the retailer the capital charge for the replaced meter.

Card-operated meter customers

If a customer is an excluded customer (as defined in section 23 of the Electricity Act), the distribution entity may at its absolute discretion agree with the relevant local government authority on behalf of the customer, and the customer's retailer, that the electricity used by the customer is to be measured and charged by means of a card-operated meter.

If, immediately prior to 1 July 2007, electricity being used by a customer at premises is being measured and charged by means of a card-operated meter, the electricity used at the premises may continue to be measured or charged by means of a card-operated meter.

Residential customers with card-operated meters can access Tariff 11 as their primary tariff, and Tariffs 31 and 33 as secondary tariffs.

Small business customers with card-operated meters can access Tariff 20 as their primary tariff.

Charges will be those as set out in Part 2 for the particular tariff.

EasyPay Reward
From 1 December 2017 until 30 September 2020, small customers of Ergon Energy who participate in the EasyPay Reward Scheme will receive annual reward amounts in the form of deferred payments.

The EasyPay Reward Scheme will operate as follows:

1. An eligible customer opts-in to the EasyPay Reward Scheme, and becomes a participating customer, by notifying Ergon Energy that it agrees to comply with all the participation requirements.
2. Subject to paragraph 3, if Ergon Energy receives a notice mentioned in paragraph 1 it must include the relevant annual amount for the participating customer in:
   (a) the first bill it issues to the customer after receiving the notice under paragraph 1, or otherwise, as soon as reasonably practicable thereafter; and
   (b) thereafter until the EasyPay Reward Scheme ends on 30 September 2020—the bill Ergon Energy issues to the customer after each anniversary of the date the customer became a participating customer.

   The following table illustrates how the scheme is intended to operate for participating customers other than small, non-reversionary customers:

	Customers who opt in on or before 30.09.18	Customers who opt in after 30.09.18 but before 01.04.19	Customers who opt in after 01.04.19 but before 01.01.20
No. of relevant annual amounts invoiced	3	2	1

3. Subject to paragraph 4, a participating customer's obligation to pay each relevant annual amount:
   (a) is deferred for the initial period; and
   (b) ceases to exist when the initial period ends.
4. However, the relevant annual amount may become payable to Ergon Energy if, on or before the end of the initial period:
   a) the participating customer opts out of having opted in;
   b) the participating customer does not maintain payment of bills by direct debit or CentrePay (as relevant); or
   c) the participating customer no longer agrees to comply with 1 or more of the participation requirements.

Ergon Energy reserves the right to recover the deferred amount from the customer on their next bill.

Definitions for EasyPay Reward Scheme
Eligible customer means a small customer who has a new or existing account with Ergon Energy under a standard retail contract and who is up to date with their bill payments. A customer with an arrears component or any overdue amount is not eligible for the Scheme.

Ergon Energy means Ergon Energy Queensland Pty Ltd (ABN 11 121 177 802)

Initial period means for a period of six months from the date that Ergon Energy issues the bill that includes the first relevant annual amount.

Participating customer means a small customer under a standard retail contract with Ergon Energy who has opted in to the Scheme.

Participation requirements means each of the following:

a) agreeing to the receive the relevant annual amount in the form of a deferred payment;
b) agreeing to receive, and receiving, only electronic bills;
c) agreeing to pay, and paying, bills by direct debit or CentrePay;
d) agreeing to make, and making, weekly, fortnightly or monthly payments (as agreed) under a *smoothpay* arrangement.

Relevant NERL amendment means an amendment to section 19C(1)(b)(ii) of the *National Energy Retail Law (Queensland)* that inserts the words 'if the customer is a large customer' before the words 'the financially responsible retailer for the premises' in section 19C(1)(b)(ii).

Relevant annual amount, for a participating customer, means:

a) if the participating customer is a residential customer—$75; or
b) if the participating customer is a business customer—$120.

Other retail fees and charges
A retailer may charge its Standard Contract Customers the following:

(a) if, at a customer's request, the retailer provides historical billing data which is more than two years old:
  – a maximum of **$30**

(b) retailer's administration fee for a dishonoured payment:
  – a maximum of **$15**

(c) financial institution fee for a dishonoured payment:
  – a maximum of **the fee incurred by the retailer**

(d) in addition to the applicable tariff, an additional amount in accordance with a program or scheme for the purchase of electricity from renewable or environmentally-friendly sources (whether or not that additional amount is calculated on the basis of the customer's electricity usage), but only if:
  (i) the customer voluntarily participates in such program or scheme;
  (ii) the additional amount is payable under the program or scheme; and
  (iii) the retailer gives the customer prior written notice of any change to the additional amount payable under the program or scheme.

In the absence of a notified price, a retailer may charge a customer for the provision of distribution entity alternate control services at the prices regulated by the Australian Energy Regulator for those services, on a cost pass through basis. These charges may be applied to a customer's bill in addition to the notified prices contained in this Tariff Schedule.

Concessional application

Tariff 11, Tariff 12A, Tariff 14, and Tariff 15 are also available to customers where they satisfy the additional criteria set out in any one of 1, 2 or 3, below:

1. Separately metered installations where all electricity used is in connection with the provision of a Meals-on-Wheels service, or for the preparation and serving of meals to the needy and for no other purpose.

2. Residential institutions:

(a) where the total installation, or that part supplied and separately metered, must be domestic residential (i.e. it must include the electricity usage of the cooking, eating, sleeping and bathing areas which are associated with the residential usage). Medical facilities, e.g. an infirmary, which are part of the complex may be included; and

(b) that are:

(i) a deductible gift recipient under section 30-227(2) of the *Income Tax Assessment Act 1997* to which donations of $2.00 and upwards are tax deductible; and

(ii) a non-profit organisation that:

A. imposes no scheduled charge on the residents for the services or accommodation that is provided (i.e. organisations that provide emergency accommodation facilities for the needy); or

B. if scheduled charges are made for the services or accommodation provided, then all residents must be pensioners or, if not pensioners, persons eligible for subsidised care under the *Aged Care Act 1997* or the *National Health Act 1953*.

3. Organisations providing support and crisis accommodation which:

(a) meet the eligibility criteria of the Specialist Homelessness Services administered by the State Department of Housing and Public Works; and

(b) are a deductible gift recipient under section 30-227(2) of the *Income Tax Assessment Act 1997* to which donations of $2.00 and upwards are tax deductible.

Part 2—Standard tariffs

These tariffs are applicable subject to the matters set out in part 1.

Small customer tariffs

Tariff	Description	Charge type	Rate	Unit
11	Residential flat-rate primary tariff	Usage	23.709	c/kWh
		Daily supply charge	90.812	c
12A	Residential seasonal time-of-use primary tariff	Summer usage – Peak (3pm–9:30pm)	61.866	c/kWh
		Summer usage – All other times	19.473	c/kWh
		Usage – All other times	19.473	c/kWh
		Daily supply charge	83.657	c
14	Residential seasonal time-of-use monthly demand primary tariff.	Chargeable demand – Peak	61.691	$/kW
	Daily demand is the average of the 13 half-hourly demand recordings for each day from 3:00pm to 9:30pm for the Peak period (Summer) and the Off-peak period (all other times).	Chargeable Demand – Off peak	8.859	$/kW
		Usage	15.532	c/kWh
	Peak chargeable demand is the average of the four highest peak daily demands in the month.	Daily supply charge	45.109	c
	Off-peak chargeable demand is the greater of the average of the four highest off-peak daily demands in the month, or 3kW.			
15	Residential primary tariff	Top up charge	9.641	$/kWh/month
	Top up charge applies to any consumption that exceeds the summer peak window consumption cap for the account's nominated band.	Usage	15.415	c/kWh
	-Band 1 has a 0 kWh cap during the summer peak window	Fixed charge - band 1	25.885	$/month
	-Band 2 has a 5 kWh cap during the summer peak window	Fixed charge - band 2	42.296	$/month
	-Band 3 has a 10 kWh cap during the summer peak window	Fixed charge - band 3	58.707	$/month
	-Band 4 has a 15 kWh cap during the summer peak window	Fixed charge - band 4	75.117	$/month
	-Band 5 has a 20 kWh cap during the summer peak window	Fixed charge - band 5	91.528	$/month
20	Small business flat-rate primary tariff.	Usage	23.918	c/kWh
		Daily supply charge	125.589	c

Tariff	Description	Charge type	Rate	Unit
22A	Small business seasonal time-of-use primary tariff.	Summer usage – Peak (10am–8pm weekdays)	59.572	c/kWh
		Summer usage – All other times	22.394	c/kWh
		Usage – All other times	22.394	c/kWh
		Daily supply charge	125.589	c
24	Small business seasonal time-of-use monthly demand primary tariff. Daily demand is the average of the 20 half-hourly demand recordings for each weekday from 10:00am to 8:00pm for the Peak period (Summer) and the Off-peak period (all other times). Peak chargeable demand is the average of the four highest peak daily demands in the month. Off-peak chargeable demand is the greater of the average of the four highest off-peak daily demands in the month, or 3kW.	Chargeable demand – Peak	81.342	$/kW
		Chargeable Demand – Off peak	8.174	$/kW
		Usage	16.379	c/kWh
		Daily supply charge	61.778	c
31	Small customer flat-rate secondary tariff with interruptible supply. Supply will be available for a minimum of 8 hours per day for customers connected to the Ergon Energy network, and 5 hours per day for customers connected to the Essential Energy network, but times when supply is available is subject to variation at the absolute discretion of the distribution entity. In general, this supply will be between the hours of 10.00 pm and 7.00 am.	Usage	17.973	c/kWh
33	Small customer flat-rate secondary tariff with interruptible supply. Supply will be available for a minimum of 18 hours per day for customers connected to the Ergon Energy network, and 10 hours per day for customers connected to the Essential Energy network, but times when supply is available is subject to variation at the absolute discretion of the distribution entity.	Usage	19.284	c/kWh
41	Small business monthly demand primary tariff.	Demand	22.451	$/kW
		Usage	14.600	c/kWh
		Daily supply charge	540.969	c

Large customer tariffs

Tariff	Description	Charge type		Unit
44	Large business monthly demand primary tariff Demand threshold 30 kW.	Chargeable demand	36.300	$/kW
		Usage	12.410	c/kWh
		Daily supply charge	4580.008	c
45	Large business monthly demand primary tariff Demand threshold 120 kW.	Chargeable demand	26.855	$/kW
		Usage	12.410	c/kWh
		Daily supply charge	15330.070	c
46	Large business monthly demand primary tariff Demand threshold 400 kW.	Chargeable demand	22.002	$/kW
		Usage	12.398	c/kWh
		Daily supply charge	40247.824	c
50	Large business seasonal time-of-use monthly demand primary tariff. Peak is Summer, being 10:00am to 8:00pm on Summer weekdays for determining chargeable demand, and all day each day for usage. Off-peak is all times in non-summer months for determining chargeable demand and usage. Peak demand threshold 20 kW. Off peak demand threshold 40 kW.	Peak chargeable demand	66.860	$/kW
		Peak usage	12.054	c/kWh
		Off-peak chargeable demand	11.646	$/kW
		Off-peak usage	14.533	c/kWh
		Daily supply charge	3570.587	c
51A	Large business high-voltage monthly demand primary tariffs only for customers classified as CAC and supplied at 66kV.	Demand	2.739	$/kVA
		Capacity	4.540	$/kVA
		Excess reactive demand	4.454	$/kvar
		Usage	11.953	c/kWh
		Daily connection charge	10.339	$/unit
		Daily supply charge	22977.574	c
51B	Large business high-voltage monthly demand primary tariffs only for customers classified as CAC and supplied at 33kV.	Demand	2.823	$/kVA
		Capacity	5.574	$/kVA
		Excess reactive demand	4.454	$/kvar
		Usage	11.953	c/kWh
		Daily connection charge	10.339	$/unit

		Daily supply charge	16084.324	c
51C	Large business high-voltage monthly demand primary tariffs only for customers classified as CAC and supplied on an 11 or 22kV bus.	Demand	3.424	$/kVA
		Capacity	6.488	$/kVA
		Excess reactive demand	4.454	$/kvar
		Usage	11.957	c/kWh
		Daily connection charge	10.339	$/unit
		Daily supply charge	14599.624	c
51D	Large business high-voltage monthly demand primary tariffs only for customers classified as CAC and supplied on an 11 or 22kV line.	Demand	6.905	$/kVA
		Capacity	12.708	$/kVA
		Excess reactive demand	4.454	$/kvar
		Usage	11.978	c/kWh
		Daily connection charge	10.339	$/unit
		Daily supply charge	13751.224	c
52A	Large business high-voltage seasonal time-of-use monthly demand primary tariffs only for customers classified as CAC and supplied at 33 or 66kV. Chargeable demand is the maximum demand between 10:00am and 8:00pm Summer weekdays. Chargeable capacity excludes all demands occurring during the chargeable demand periods.	Chargeable demand	12.248	$/kVA
		Chargeable capacity	6.945	$/kVA
		Excess reactive demand	4.454	$/kvar
		Usage – Summer	11.473	c/kWh
		Usage – All other times	11.884	c/kWh
		Daily connection charge	10.339	$/unit
		Daily supply charge	10251.574	c

52B	Large business high-voltage seasonal time-of-use monthly demand primary tariffs only for customers classified as CAC and supplied on an 11 or 22kV bus. Chargeable demand is the maximum demand between 10:00am and 8:00pm Summer weekdays. Chargeable capacity excludes all demands occurring during the chargeable demand periods.	Chargeable demand	46.137	$/kVA
		Chargeable capacity	4.890	$/kVA
		Excess reactive demand	4.454	$/kvar
		Usage – Summer	11.477	c/kWh
		Usage – All other times	11.888	c/kWh
		Daily connection charge	10.339	$/unit
		Daily supply charge	10251.574	c
52C	Large business high-voltage seasonal time-of-use monthly demand primary tariffs only for customers classified as CAC and supplied on an 11 or 22kV line. Chargeable demand is the maximum demand between 10:00am and 8:00pm Summer weekdays. Chargeable capacity excludes all demands occurring during the chargeable demand periods.	Chargeable demand	80.540	$/kVA
		Chargeable capacity	8.999	$/kVA
		Excess reactive demand	4.454	$/kvar
		Usage – Summer	11.498	c/kWh
		Usage – All other times	11.909	c/kWh
		Daily connection charge	10.339	$/unit
		Daily supply charge	10251.574	c
53	Large business high-voltage monthly primary tariff only for customers classified as ICC.	Demand	6.905	$/kVA
		Capacity	12.708	$/kVA
		Excess reactive demand	4.454	$/kvar
		Usage	11.978	c/kWh
		Daily supply charge	13560.395	c

Part 3—Obsolete tariffs.

These tariffs are applicable subject to the matters set out in part 1.

Tariff	Description	Charge type	*Rate*	Unit
20 (large)	Obsolete large business flat-rate primary tariff. Scheduled phase-out date: 1 July 2020	Usage	37.595	c/kWh
		Daily supply charge	76.858	c

21	Obsolete business declining-block primary tariff. Scheduled phase-out date: 1 July 2020	Usage – first 100 kWh/month	49.357	c/kWh
		Usage – next 9,900 kWh/month	46.374	c/kWh
		Usage – all remaining usage	35.303	c/kWh
		Minimum daily payment	72.631	c
22 (small and large)	Obsolete business time-of-use primary tariff. Scheduled phase-out date: 1 July 2020	Usage – 7am to 9pm weekdays	49.820	c/kWh
		Usage – all other times	17.543	c/kWh
		Daily supply charge	184.717	c
37	Obsolete business time-of-use primary tariff. Scheduled phase-out date: 1 July 2020	Usage – 4:30pm–10:30pm	54.544	c/kWh
		Usage – all other times	21.807	c/kWh
		Minimum daily payment	30.623	c
47	Obsolete large business high voltage monthly demand primary tariff. Demand threshold 400 kW Scheduled phase-out date: 1 July 2022	Chargeable demand	27.864	$/kW
		Usage	12.446	c/kWh
		Daily supply charge	44689.726	c
48	Obsolete large business high voltage monthly demand primary tariff only for customers classified as CAC or ICC. Demand threshold 400 kW Scheduled phase-out date: 1 July 2022	Chargeable demand	28.822	$/kW
		Usage	12.874	c/kWh
		Daily supply charge	46712.140	c
62	Obsolete farming business time-of-use declining-block primary tariff. Scheduled phase-out date: 1 July 2020	Usage – 7am to 9pm weekdays first 10,000kWh per month	46.516	c/kWh
		Usage – 7am to 9pm weekdays all remaining usage	39.336	c/kWh
		Usage – all other times	16.448	c/kWh
		Daily supply charge	78.451	c
65	Obsolete irrigation business time-of-use primary tariff. Scheduled phase-out date: 1 July 2020	Usage – Peak (daily pricing period)	36.894	c/kWh
		Usage – all other times	20.321	c/kWh
		Daily supply charge	78.003	c

66	Obsolete irrigation business fixed annual dual-rate demand primary tariff. Scheduled phase-out date: 1 July 2020	Fixed charge (annual) – first 7.5kW	37.503	$/kW
		Fixed charge (annual) – remaining kW	112.759	$/kW
		Usage	19.338	c/kWh
		Daily supply charge	171.915	c

Part 4—Unmetered supply tariffs

These tariffs are applicable subject to the matters set out in part 1.

Tariff	Description	Charge type	Rate	Unit
71	Business flat-rate primary tariff for street lighting.	Usage	28.416	c/kWh
		Daily supply charge	0.420	c/lamp
91	Business flat-rate primary tariff.	Usage	21.510	c/kWh

Part 5—Metering charges

Large customer—type 1, 2, 3, 4 (advanced digital) meters

Description	Charge type	Rate	Unit
Standard asset customer	Daily metering charge	160.761	c
Standard asset customer (annual consumption greater than 750GWh)	Daily metering charge	202.308	c
Connection asset customer	Daily metering charge	430.801	c
Individually calculated customer	Daily metering charge	434.813	c

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End of Tariff Schedule

APPENDIX G: ASSUMPTIONS AND DATA USED TO DETERMINE CUSTOMER IMPACTS

Typical customer figures are based on the annual consumption of the median customer on each tariff in regional Queensland. Consistent with previous price determinations, Ergon Distribution provided the forecast usage for tariffs 12A and 22A[143], while Ergon Retail provided actual usage data for the remaining tariffs.

The median customer is the middle customer in terms of consumption out of all customers on each tariff. As such, approximately half of all customers will use less electricity than the typical figure, and half will use more. Stakeholders requested the QCA provide a range of bill impacts for residential customers. One quarter of customers will use less electricity than the 25th percentile customer, while three-quarters of customers will use less electricity than the 75th percentile customer.

In submissions for previous determinations, stakeholders noted that the typical customer figures provided by Ergon Retail appear lower than those on the AER's Energy Made Easy website. The reason for the discrepancy is that the Energy Made Easy website uses average consumption figures based on a survey of 4,000 customers across Australia in 2014, while Ergon Retail uses actual consumption figures from their customer base of over 700,000 electricity customers in regional Queensland.

Table 36 Usage data used to determine customer impacts

Retail tariff	*Usage (kWh per year)*	*Peak usage (%)*	*Off-peak usage (%)*	*Demand (kW per month)*	*Demand threshold (kW per month)*
T11 (only)—25th percentile	2,274				
T11 (only)—median	3,738				
T11 (only)—75th percentile	5,855				
T11 (with T31)—median	5,734				
T31—median	1,441				
T11 (with T33)—median	5,464				
T33—median	1,063				
T20—median	6,866				
T12A—median	4,644	16.9%	83.1%		
T22A—median	7,457	16.7%	83.3%		
T44—median	2,546,844			58	30
T45–median	9,884,448			204	120
T46–median	26,802,432			526	400

[143] Forecast data were provided, as actual usage data were considered unreliable due to the very small number of customers on these tariffs.

APPENDIX H: SUMMARY OF CONCESSIONAL ARRANGEMENTS FOR ELECTRICITY IN QUEENSLAND

Concession	*Eligibility criteria*	*Annual amount (including GST)*
Electricity Rebate	Rebates are available to people who have any of the below: • Pensioner Concession Card • Department of Veterans' Affairs Gold Card (and receive the War Widow/er Pension or special rate TPI Pension) • Queensland Seniors Card. • Commonwealth Health Care Card (Electricity Rebate only) • Asylum seeker status (residents will need to provide their ImmiCard details) (Electricity Rebate only) To be eligible, you must be the electricity account holder and also live alone or share your principal place of residence with (only) any of the below: • their spouse • other people who hold a Pensioner Concession Card or Queensland Seniors Card • other people wholly dependent on them • other people who receive an income support payment from Centrelink, the Family Assistance Office, or the Department of Veterans' Affairs and who do not pay rent • other people who live with the card holder to provide care and assistance, and who do not pay rent. If you live in a caravan park or multi-unit residential building (e.g. apartment), you must also show that your electricity or reticulated natural gas is paid on the basis of metered consumption.	$340.85
Electricity rebate (for residential home parks and multi-unit residential premises)	The rebate is available for premises where the proprietor/owner: • is the consumer of the energy retailer • supplies electricity and/or reticulated natural gas to each of the separately identifiable vans, flats or home units • charges for electricity and/or reticulated natural gas used by residents based on metered consumption. To be eligible, residents must have one of the following: • a current Pensioner Concession Card issued by Centrelink • a current Department of Veterans' Affairs (DVA) Gold Card (Totally and Permanently Incapacitated (TPI) and widow/er only) • a current Queensland Seniors Card • a current Commonwealth Health Care Card (issued by Centrelink) (Electricity Rebate only) • asylum seeker status (residents will need to provide their ImmiCard details) (Electricity Rebate only). Eligible residents must live alone or share the premises with:	$0.9338 per day

Concession	***Eligibility criteria***	***Annual amount (including GST)***
	• their spouse or other eligible card holders • other people wholly dependent on them • other people who are social security recipients, and who do not pay rent • other people who live with the resident to provide care and assistance, and who do not pay rent.	
Electricity asset ownership dividend	To provide continued electricity bill relief for all Queensland households, $200 million from the dividends of government owned corporations will be delivered as a $50 per year ($100 over 2 years) rebate for households over the next 2 years. Households will automatically receive their first $50 rebate from the second quarter of 2018. Customers don't need to apply for the rebate—it will be automatically applied to each residential electricity account.	$50.00
No interest loans and rebates for rooftop solar and battery systems	To drive continued uptake of solar, and support customers to adopt battery storage technology, $21 million is being committed to provide no interest loans for these technologies. The no interest loans enable households and small businesses to access the necessary upfront capital required to purchase systems.	
Home Energy Emergency Assistance Scheme	The Home Energy Emergency Assistance Scheme: • is for Queensland households experiencing problems paying their electricity or reticulated natural gas bills as a result of an unforeseen emergency or a short-term financial crisis • is one-off emergency assistance to help with paying your home energy bills • pays up to $720 once every 2 years. To be eligible, customers must be responsible for paying the outstanding bill (the bill does not need to be in your name) and meet one of the following: • hold a current concession card • have an income equal to or less than the Australian Government's maximum income rate for part-age pensioners. Contact Centrelink for details of the maximum income rate • be part of your energy retailer's hardship program or payment plan.	Up to $720 once every two years.
Electricity Life Support Concession Scheme	Customers must be medically assessed in accordance with the eligibility criteria determined by Queensland Health. In addition, oxygen concentrators must be provided rent-free by Queensland Health to persons who hold an eligible concession card and meet the eligibility criteria of the Medical Aids Subsidy Scheme. Kidney dialysis machines must be provided rent-free by Queensland Health to persons based on clinical needs and supplied through Queensland hospitals.	$694.18 per year for each oxygen concentrator. $464.88 for each kidney dialysis machine.

Concession	***Eligibility criteria***	***Annual amount (including GST)***
Medical Cooling and Heating Electricity Concession Scheme	The Medical Cooling and Heating Electricity Concession Scheme helps with electricity costs for people who have a chronic medical condition, such as multiple sclerosis, autonomic system dysfunction, significant burns or a severe inflammatory skin condition, which is aggravated by changes in temperature.	$340.85
Drought relief from Electricity Charges Scheme	The Drought Relief from Electricity Charges Scheme (DRECS) provides relief from supply charges on electricity accounts that are used to pump water for farm or irrigation purposes. Financial assistance is available in drought-declared areas or if your property has been drought-declared. You can apply for a waiver or reimbursement of supply charges on all relevant electricity accounts.	

Note: For more information, see https://www.qld.gov.au/community/cost-of-living-support/energy-concessions.

APPENDIX I: BUILD-UP OF NOTIFIED PRICES

Table 37 Regulated retail tariffs and prices for residential customers (GST exclusive)

Retail tariff	*Tariff component*	*Fixed[a] (c/day)*	*Peak usage (c/kWh)*	*Off-peak/Flat usage (c/kWh)*	*Peak demand ($/kW/mth)*	*Off-peak/Flat demand ($/kW/mth)*
Tariff 11—Residential (flat-rate)	Network	49.000		8.762		
	Energy			11.531		
	Fixed retail	37.488				
	Variable retail			2.287		
	Standing offer adjustment	4.324		1.129		
	SRES cost pass-through					
	Total	**90.812**		**23.709**		
Tariff 12A—Residential (seasonal time-of-use)	Network	42.185	41.421	5.136		
	Energy		11.531	11.531		
	Fixed retail	37.488				
	Variable retail		5.968	1.878		
	Standing offer adjustment	3.984	2.946	0.927		
	SRES cost pass-through					
	Total	**83.657**	**61.866**	**19.473**		
Tariff 14—Residential (seasonal time-of-use demand)	Network	5.473		1.763	52.802	7.583
	Energy			11.531		
	Fixed retail	37.488				
	Variable retail			1.498	5.951	0.855
	Standing offer adjustment	2.148		0.740	2.938	0.422
	SRES cost pass-through					
	Total	**45.109**		**15.532**	**61.691**	**8.859**
Tariff 31—Night rate super economy	Network			6.421		
	Energy			8.962		
	Fixed retail					
	Variable retail			1.734		
	Standing offer adjustment			0.856		

Retail tariff	*Tariff component*	*Fixed[a] (c/day)*	*Peak usage (c/kWh)*	*Off-peak/Flat usage*	*Peak demand ($/kW/mth)*	*Off-peak/Flat demand*
	SRES cost pass-through					
	Total			**17.973**		
Tariff 33—Controlled supply economy	Network			6.736		
	Energy			9.769		
	Fixed retail					
	Variable retail			1.860		
	Standing offer adjustment			0.918		
	SRES cost pass-through					
	Total			**19.284**		

a *Charged per metering point.*

Note: Totals may not add due to rounding.

Table 38 Regulated retail tariffs and prices for residential customers (GST exclusive)

Retail Tariff	*Tariff Component*	*Fixed Band 1 ($/mth)*	*Fixed Band 2 ($/mth)*	*Fixed Band 3 ($/mth)*	*Fixed Band 4 ($/mth)*	*Fixed Band 5 ($/mth)*	*Usage (c/kWh)*	*Top up Charge ($/kWh/mth)*
Tariff 15—Residential	Network	13.242	28.872	44.501	60.130	75.759	1.663	8.252
	Energy						11.531	
	Fixed retail	11.410	11.410	11.410	11.410	11.410		
	Variable retail						1.487	0.930
	Standing offer adjustment	1.233	2.014	2.796	3.577	4.358	0.734	0.459
	SRES cost pass-through							
	Total	**25.885**	**42.296**	**58.707**	**75.117**	**91.528**	**15.415**	**9.641**

Note: Totals may not add due to rounding.

Table 39 Regulated retail tariffs and prices for small business and unmetered supply customers (GST exclusive)

Retail tariff	*Tariff component*	*Fixed[a] (c/day)*	*Peak usage (c/kWh)*	*Off-peak/Flat usage (c/kWh)*	*Peak demand ($/kW/mth)*	*Off-peak/Flat demand ($/kW/mth)*
Tariff 20—Business (flat-rate)	Network	66.500		8.663		
	Energy			11.531		
	Fixed retail	53.108				
	Variable retail			2.585		
	Standing offer adjustment	5.980		1.139		
	SRES cost pass-through					
	Total	**125.589**		**23.918**		
Tariff 22A—Business (seasonal time-of-use)	Network	66.500	38.766	7.376		
	Energy		11.531	11.531		
	Fixed retail	53.108				
	Variable retail		6.438	2.420		
	Standing offer adjustment	5.980	2.837	1.066		
	SRES cost pass-through					
	Total	**125.589**	**59.572**	**22.394**		
Tariff 24—Business (seasonal time-of-use demand)	Network	5.728		2.298	68.678	6.901
	Energy			11.531		
	Fixed retail	53.108				
	Variable retail			1.770	8.791	0.883
	Standing offer adjustment	2.942		0.780	3.873	0.389
	SRES cost pass-through					
	Total	**61.778**		**16.379**	**81.342**	**8.174**
Tariff 41—Business low voltage (demand)	Network	462.100		0.796		18.956
	Energy			11.531		
	Fixed retail	53.108				
	Variable retail			1.578		2.426
	Standing offer adjustment	25.760		0.695		1.069
	SRES cost pass-through					

Retail tariff	***Tariff component***	***Fixed[a] (c/day)***	***Peak usage (c/kWh)***	***Off-peak/Flat***	***Peak demand ($/kW/mth)***	***Off-peak/Flat demand***
	Total	**540.969**		**14.600**		**22.451**
Tariff 91—Unmetered supply	Network			6.630		
	Energy			11.531		
	Fixed retail					
	Variable retail			2.325		
	Standing offer adjustment			1.024		
	SRES cost pass-through					
	Total			**21.510**		

a *Charged per metering point.*

Note: Totals may not add due to rounding

Table 40 Regulated retail tariffs and prices for large business and street lighting customers (GST exclusive)

Retail tariff	*Tariff component*	*Fixed[a] (c/day)*	*Peak usage (c/kWh)*	*Off-peak/Flat usage (c/kWh)*	*Peak demand ($/kW/mth)*	*Off-peak/Flat demand ($/kW/mth)*
Tariff 44—Business over 100 MWh/yr—Small (demand)	Network	3982.100		1.298		32.601
	Energy			9.847		
	Fixed retail	379.813				
	Variable retail			0.674		1.971
	Headroom	218.096		0.591		1.729
	SRES cost pass-through					
	Total	**4580.008**		**12.410**		**36.300**
Tariff 45—Business over 100 MWh/yr—Medium (demand)	Network	13555.600		1.298		24.118
	Energy			9.847		
	Fixed retail	1044.466				
	Variable retail			0.674		1.458
	Headroom	730.003		0.591		1.279
	SRES cost pass-through					
	Total	**15330.070**		**12.410**		**26.855**
Tariff 46—Business over 100 MWh/yr—Large (demand)	Network	35674.400		1.288		19.760
	Energy			9.847		
	Fixed retail	2656.861				
	Variable retail			0.673		1.194
	Headroom	1916.563		0.590		1.048
	SRES cost pass-through					
	Total	**40247.824**		**12.398**		**22.002**
Tariff 50—Business over 100 MWh/yr (seasonal time-of-use demand)	Network	3058.500	0.978	3.205	60.047	10.459
	Energy		9.847	9.847		
	Fixed retail	342.059				
	Variable retail		0.654	0.789	3.630	0.632
	Headroom	170.028	0.574	0.692	3.184	0.555
	SRES cost pass-through					
	Total	**3570.587**	**12.054**	**14.533**	**66.860**	**11.646**
Tariff 71—	Network	0.400		15.673		

Retail tariff	***Tariff component***	***Fixed[a] (c/day)***	***Peak usage***	***Off-peak/Flat***	***Peak demand ($/kW/mth)***	***Off-peak/Flat demand***
Street lighting	Energy			9.847		
	Fixed retail					
	Variable retail			1.543		
	Headroom	0.020		1.353		
	SRES cost pass-through					
	Total	**0.420**		**28.416**		

a *Charged per metering point.*

Note: Totals may not add due to rounding.

Table 41 Regulated retail tariffs and prices for very large business customers (GST exclusive)

Retail tariff	*Tariff component*	*Fixed[a] (c/day)*	*Peak usage (c/kWh)*	*Off-peak/flat usage (c/kWh)*	*Connection unit ($/day/unit)*	*Capacity Flat/Off-peak ($/kVA of AD/mth)*	*Demand flat/peak ($/kVA/mth)*	*Excess reactive power ($/excess kVAr/mth)*
Tariff 51A—Business over 4 GWh/yr—High voltage 66kV	Network	19253.400		1.350	9.285	4.077	2.460	4.000
	Energy			9.385				
	Fixed retail	2630.004						
	Variable retail			0.649	0.561	0.246	0.149	0.242
	Headroom	1094.170		0.569	0.492	0.216	0.130	0.212
	SRES cost pass-through							
	Total	**22977.574**		**11.953**	**10.339**	**4.540**	**2.739**	**4.454**
Tariff 51B—Business over 4 GWh/yr—High voltage 33kV	Network	12688.400		1.350	9.285	5.006	2.535	4.000
	Energy			9.385				
	Fixed retail	2630.004						
	Variable retail			0.649	0.561	0.303	0.153	0.242
	Headroom	765.920		0.569	0.492	0.265	0.134	0.212
	SRES cost pass-through							
	Total	**16084.324**		**11.953**	**10.339**	**5.574**	**2.823**	**4.454**
Tariff 51C—Business over 4 GWh/yr—High voltage 22/11kV Bus	Network	11274.400		1.354	9.285	5.827	3.075	4.000
	Energy			9.385				
	Fixed retail	2630.004						
	Variable retail			0.649	0.561	0.352	0.186	0.242
	Headroom	695.220		0.569	0.492	0.309	0.163	0.212

Retail tariff	***Tariff component***	***Fixed[a] (c/day)***	***Peak usage***	***Off-peak/flat***	***Connection unit***	***Capacity***	***Demand***	***Excess reactive***
	SRES cost pass-through							
	Total	**14599.624**		**11.957**	**10.339**	**6.488**	**3.424**	**4.454**
Tariff 51D—Business over 4 GWh/yr—High voltage 22/11kV Line	Network	10466.400		1.372	9.285	11.413	6.201	4.000
	Energy			9.385				
	Fixed retail	2630.004						
	Variable retail			0.650	0.561	0.690	0.375	0.242
	Headroom	654.820		0.570	0.492	0.605	0.329	0.212
	SRES cost pass-through							
	Total	**13751.224**		**11.978**	**10.339**	**12.708**	**6.905**	**4.454**
Tariff 52A—Business over 4 GWh/yr—High voltage 66/33kV (STOUD)	Network	7133.400	0.919	1.288	9.285	6.237	11.000	4.000
	Energy		9.385	9.385				
	Fixed retail	2630.004						
	Variable retail		0.623	0.645	0.561	0.377	0.665	0.242
	Headroom	488.170	0.546	0.566	0.492	0.331	0.583	0.212
	SRES cost pass-through							
	Total	**10251.574**	**11.473**	**11.884**	**10.339**	**6.945**	**12.248**	**4.454**
Tariff 52B—Business over 4 GWh/yr—High voltage 22/11kV Bus (STOUD)	Network	7133.400	0.923	1.292	9.285	4.392	41.435	4.000
	Energy		9.385	9.385				
	Fixed retail	2630.004						
	Variable retail		0.623	0.645	0.561	0.265	2.505	0.242
	Headroom	488.170	0.547	0.566	0.492	0.233	2.197	0.212
	SRES cost pass-through							

Retail tariff	***Tariff component***	***Fixed[a] (c/day)***	***Peak usage***	***Off-peak/flat***	***Connection unit***	***Capacity***	***Demand***	***Excess reactive***
	Total	**10251.574**	**11.477**	**11.888**	**10.339**	**4.890**	**46.137**	**4.454**
Tariff 52C—Business over 4 GWh/yr—High voltage 22/11kV Line (STOUD)	Network	7133.400	0.941	1.310	9.285	8.082	72.333	4.000
	Energy		9.385	9.385				
	Fixed retail	2630.004						
	Variable retail		0.624	0.646	0.561	0.489	4.372	0.242
	Headroom	488.170	0.548	0.567	0.492	0.429	3.835	0.212
	SRES cost pass-through							
	Total	**10251.574**	**11.498**	**11.909**	**10.339**	**8.999**	**80.540**	**4.454**
Tariff 53—Business over 40 GWh/yr	Network	10466.400		1.372		11.413	6.201	4.000
	Energy			9.385				
	Fixed retail	2448.262						
	Variable retail			0.650		0.690	0.375	0.242
	Headroom	645.733		0.570		0.605	0.329	0.212
	SRES cost pass-through							
	Total	**13560.395**		**11.978**		**12.708**	**6.905**	**4.454**

a *Charged per metering point.*

Note: Totals may not add due to rounding