Queensland Competition Authority

Final determination

Regulated retail electricity prices for 2019–20

May 2019

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EXECUTIVE SUMMARY

The Queensland Competition Authority (QCA) has made its final 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 those prices 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).

Notified prices have fallen for most typical customers, largely due to decreases in energy costs, compared to 2018–19.

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

How has the QCA set 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 have calculated notified prices using a network cost plus energy and retail costs (N+R) approach, and have 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 (as illustrated in Figure 1). 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.

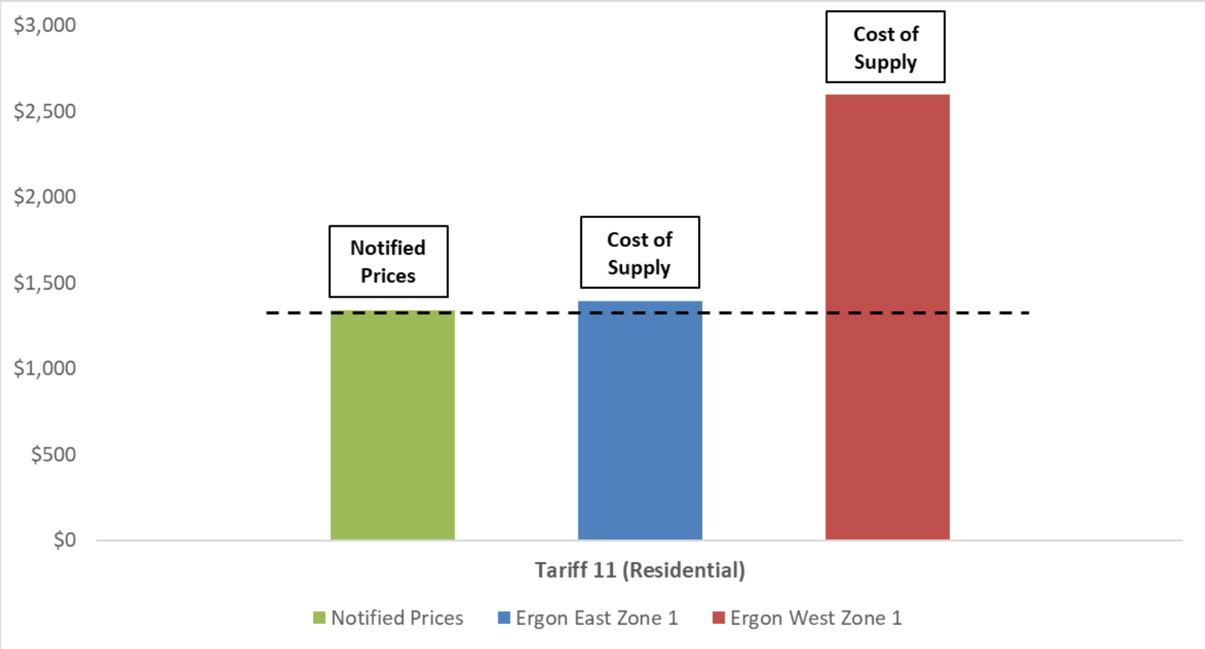
[1] According to the delegation, the government's Uniform Tariff Policy provides that, 'wherever possible, customers of the same class should pay no more for their electricity, regardless of their geographic location.'

[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, p. 162, https://budget.qld.gov.au/files/BP2-2018-19.pdf.

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 concurs with the Minister that it is appropriate to make an adjustment (referred to as the standing offer adjustment) of 5 percent for 2019–20 (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 the market 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 have included a 5 per cent headroom allowance in 2019–20 (discussed further in Chapter 6).

[5] See Appendix A.

What is the impact on customer bills?

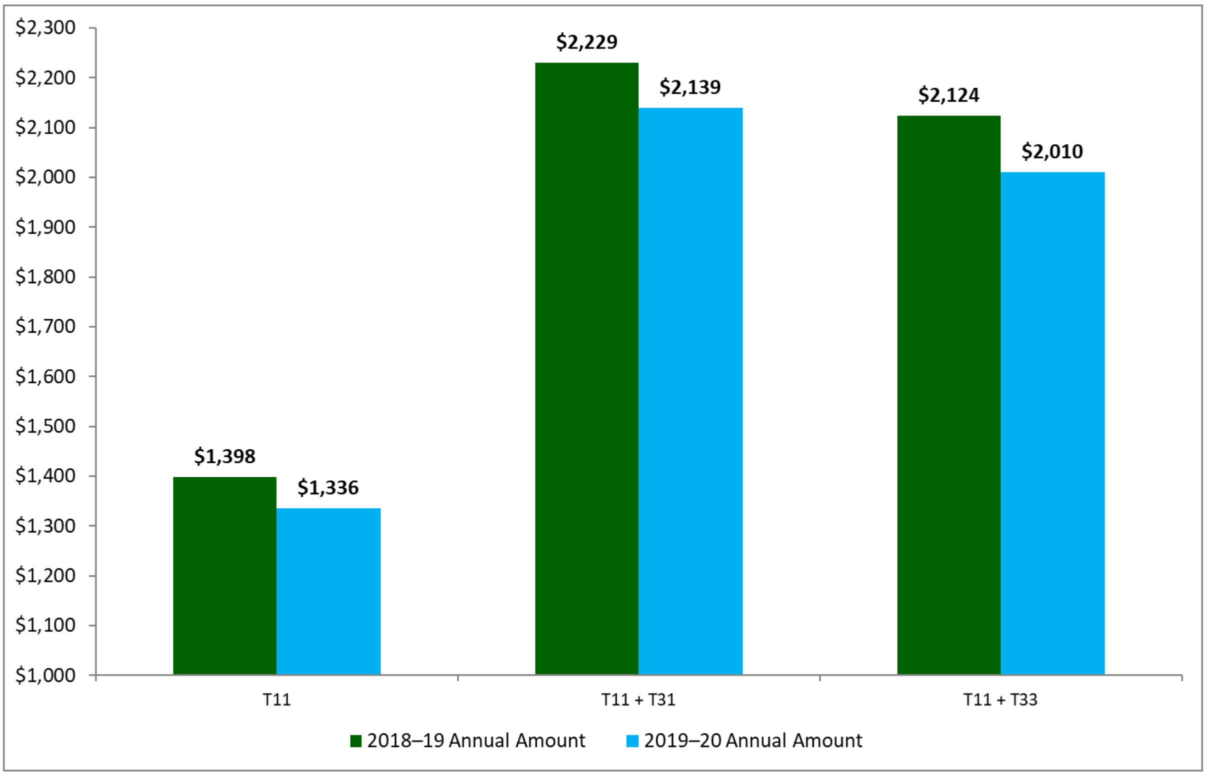
Residential customers

The typical residential customer on the main retail tariff (tariff 11) would pay around $62 (or 4.4 per cent) less per year for their electricity usage and service fee in 2019–20 (Figure 2).[6]

The typical residential customer on a combination of tariff 11 and controlled load[7] tariff 31 would pay around $90 (or 4 per cent) less per year, while the typical customer on a combination of tariff 11 and tariff 33 would pay around $114 (or 5.3 per cent) less per year.

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

Figure 2 Impact of 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 $144 (or 5.8 per cent) less per year for their electricity usage and service fee in 2019–20[8], while the typical small business customer on

[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.

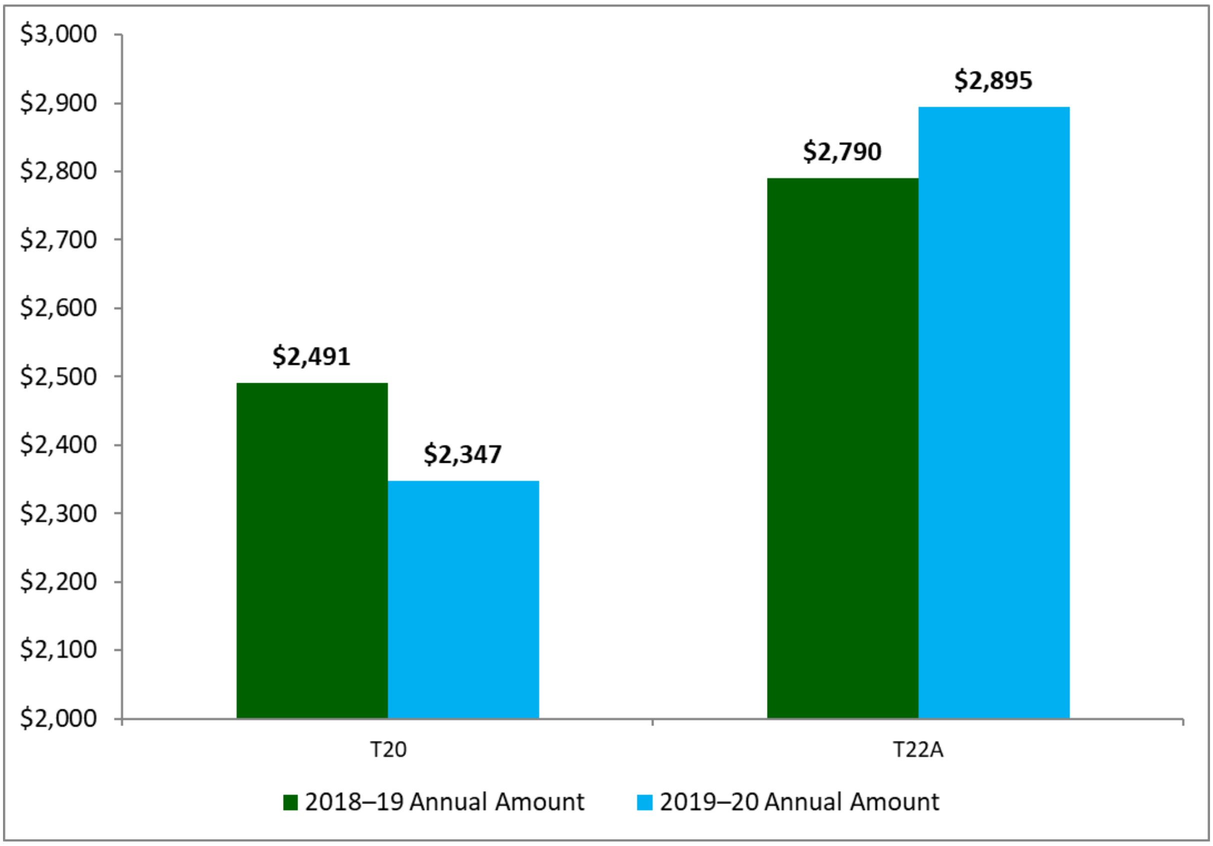
[7] Controlled load tariffs may be used for appliances such as water heaters and pool pumps. These tariffs are cheaper than tariff 11, as customers are only guaranteed supply for a set number of hours (tariff 31 guarantees supply for eight hours per day and tariff 33 guarantees supply for 18 hours per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

time-of-use tariff 22A would pay $105 (or 3.8 per cent) more per year for their electricity usage and service fee in 2019–20 (Figure 3).[9]

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

Figure 3 Impact of notified prices on typical small business customers (incl. GST), 2019–20



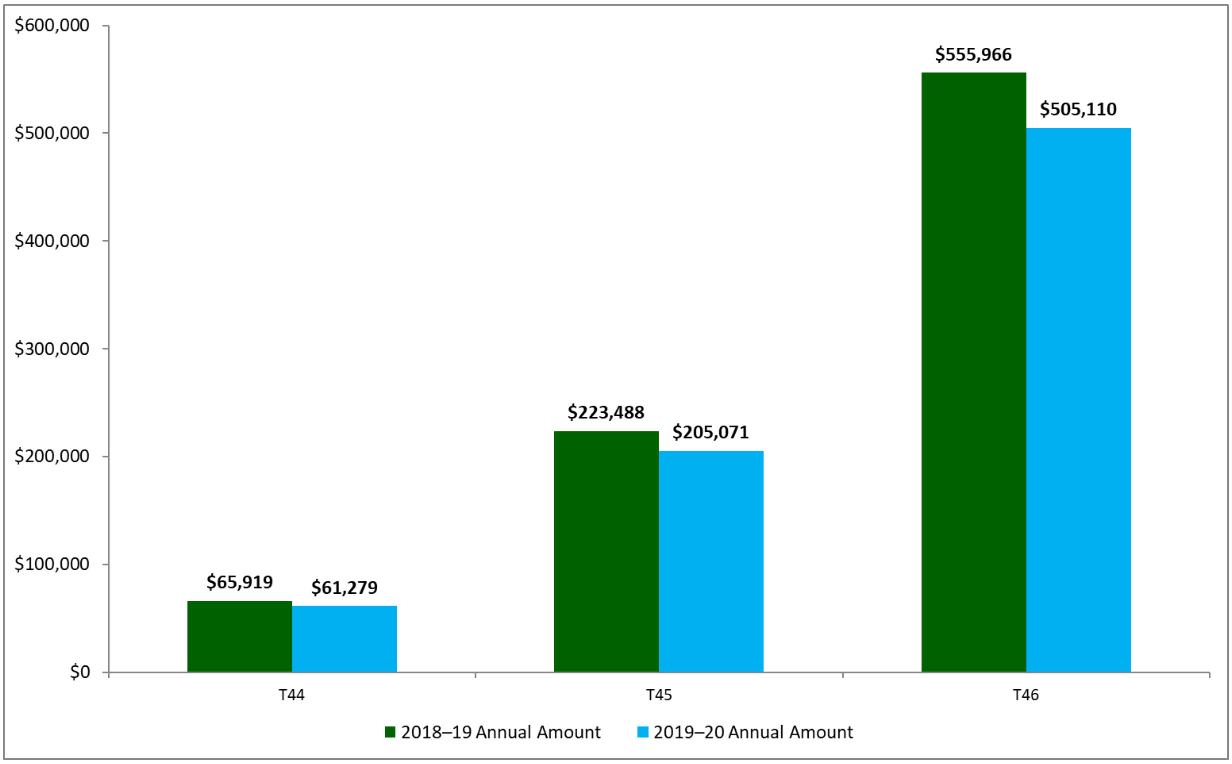
Note: Annual amounts are rounded to the closest dollar, and exclude metering charges.

Large business customers

A typical large business customer on tariff 44, 45 or 46 would pay between 7 per cent and 9.1 per cent less per year for their electricity usage and service fee in 2019–20 (Figure 4). 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 Impact of notified prices on typical large business customers (incl. GST), 2019–20



Note: Annual amounts are rounded to the closest dollar, and exclude metering charges. Changes in the annual bill calculations for typical customers since the draft determination are primarily due to the adjustment of consumption data for the typical customers, while retail prices have remained largely unchanged. Consumption data for typical customers have been adjusted since the draft determination, following further analysis of the data by QCA staff.

Obsolete tariffs

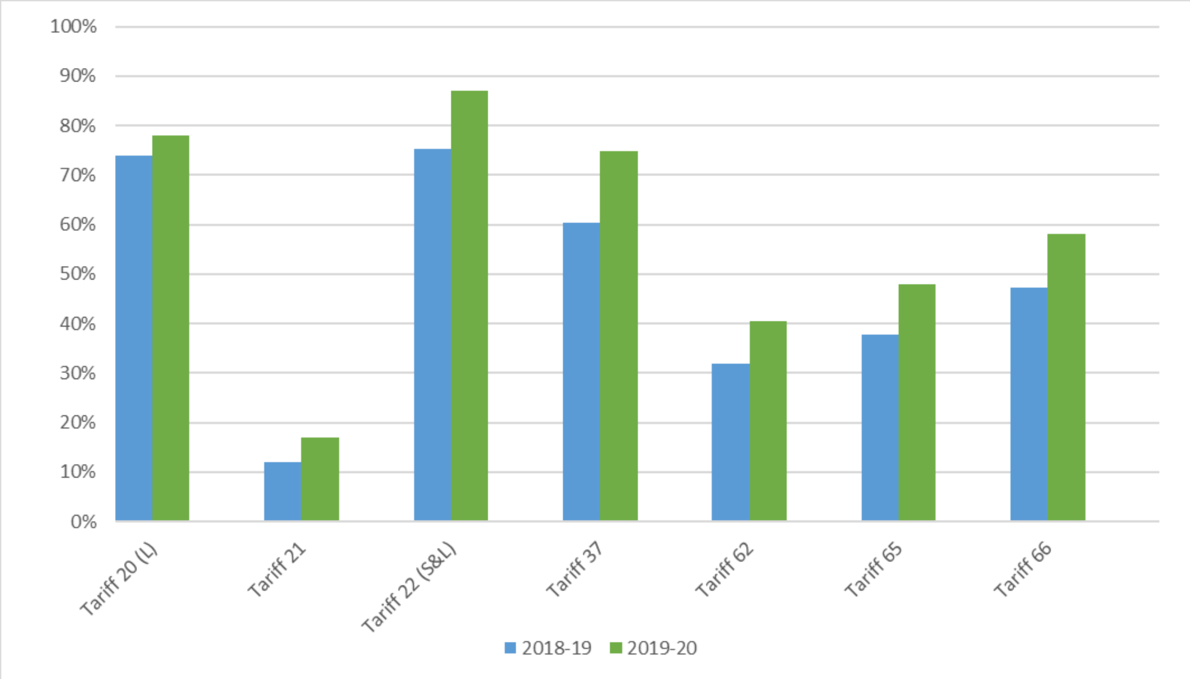
Around 35,000 connections, including some used by farmers and irrigators, are supplied under legacy retail tariffs. These tariffs were made available for several years to allow customers to transition their businesses to standard business tariffs. With the exception of tariffs 47 and 48[10], all of these tariffs will expire on 30 June 2020. In accordance with the delegation, the QCA has allowed existing customers to remain on these tariffs until they expire, but has closed 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 in 2018–19. Based on the 2019–20 notified 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

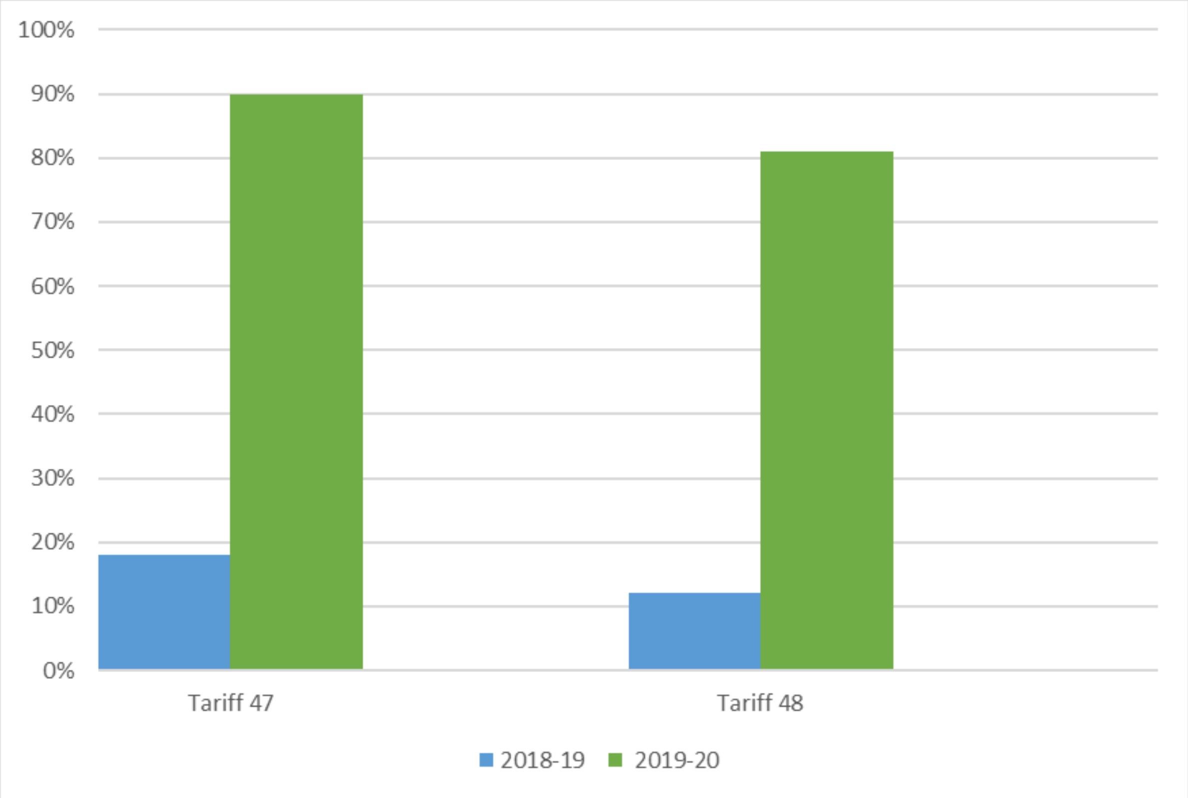


Given these tariffs will shortly expire, and significant potential exists for customers to pay less for electricity on standard business tariffs, we strongly encourage customers on expiring tariffs to contact their retailer for advice on the most appropriate tariffs for their business.

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 Approximate proportion of connections on tariffs 47 and 48 that could transition to standard business tariffs without any negative impact



Energy Analysis

Given that most obsolete tariffs are expiring in the near future, it is vital for customers on these tariffs to contact their retailer to find out what tariffs would be most suitable for their business.

Ergon Retail has established a service called Energy Analysis, which is part of the MyAccount portal. This service, available to all customers, analyses each individual's electricity bills and compares them with the equivalent bills under different electricity tariffs. This allows customers to get individually tailored information on their tariff options.

Energy Analysis can be accessed by Ergon Retail customers at

https://www.ergon.com.au/retail/business/account-options/energy-analysis-for-consolidated-accounts/register-for-energy-analysis or on 1300 554 029.

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

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1 INTRODUCTION

In December 2018, The Queensland Competition Authority (QCA) received a delegation from the Minister for Natural Resources, Mines and Energy (the Minister) to determine regulated retail electricity prices (notified prices). The delegation specified 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, at the start of our review. We received 13 submissions in response (Appendix B). The interim consultation paper and all non-confidential submissions are available on the QCA's website.[12]

Draft determination

On 28 February 2019, we released our draft determination on 2019–20 notified prices, as well as ACIL Allen's draft report on estimated energy costs. In March 2019, we held workshops in seven locations (Bundaberg, Mackay, Charleville, Ayr, Townsville, Cairns and Brisbane). We received 34 submissions on the draft determination (listed in Appendix B).

Final determination

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

We appreciate the contribution stakeholders have made to this 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 the review, are discussed in Appendix C. Non confidential documents relating to this review are available on our website.[13]

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 (Figure 7). Notified prices are not available to customers located in the Energex distribution area.[14]

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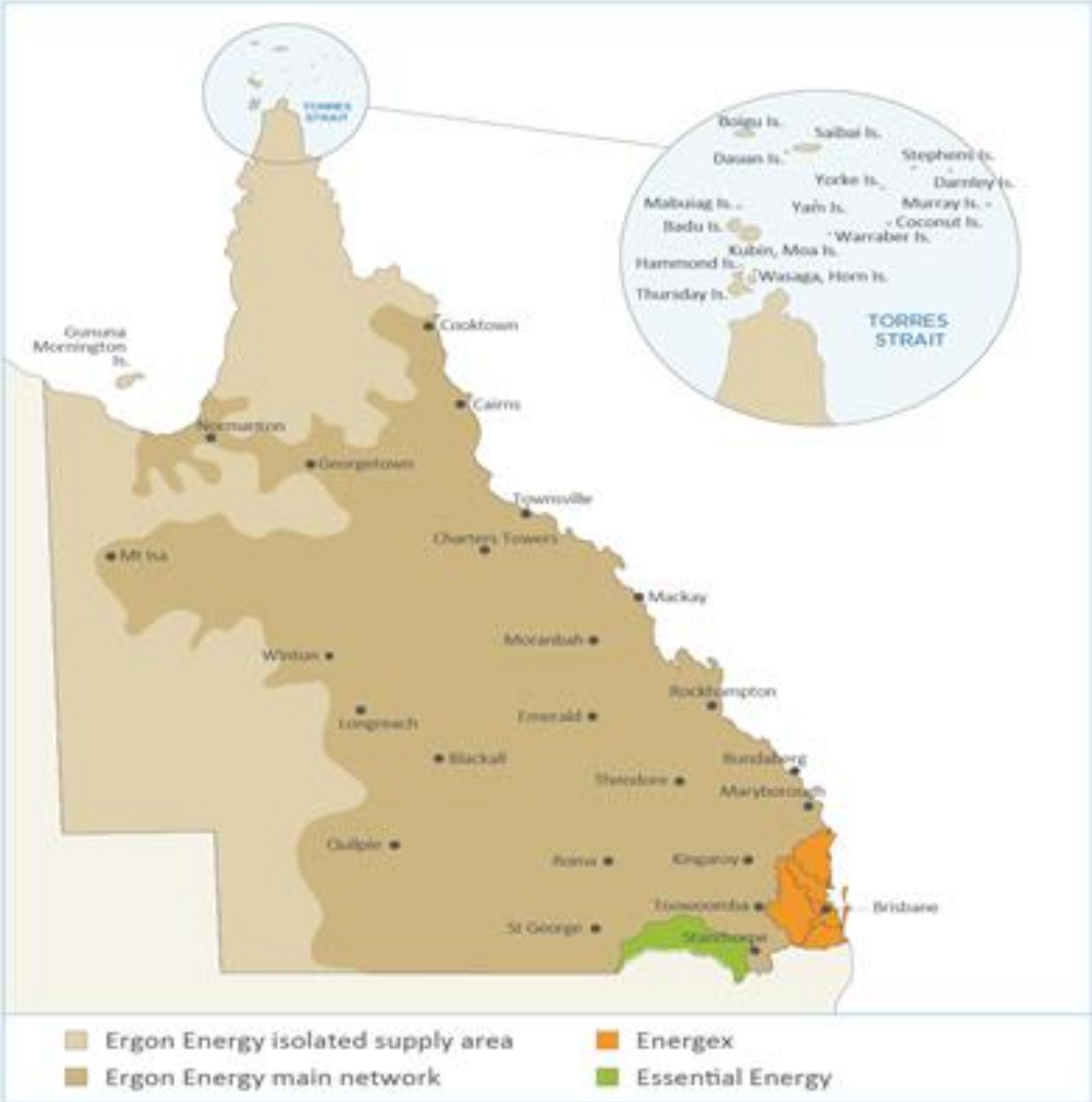
[11] See Appendix A for a copy of the delegation.

[12] http://www.qca.org.au/Electricity/Regional-consumers/Reg-Electricity-Prices/In-Progress/2019-20-Regulated-electricity-prices-for-regional

[13] http://www.qca.org.au/Electricity/Regional-consumers/Reg-Electricity-Prices

[14] 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 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.

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

(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.[15]

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:

[15] Section 90(5)(a) of the Electricity Act.

(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.[16]

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.[17]

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.[18]

The UTP provides that customers of the same class should generally pay no more for their electricity. However, the government considers that, in order to reflect the intent of the UTP, the QCA should give consideration to including an adjustment in notified prices for small customers 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.

As the actual costs of supplying residential, small business and some large business customers in regional Queensland are generally higher than notified prices, 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.

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

'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[19] for residential and small business customers (tariffs 11, 20, 31, 33, 41 and 91[20]).

When we determine time-of-use[21] and time-of-use demand retail tariffs[22] 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:

(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 (Appendix A to this report) and discussed in Chapter 6.

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:

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

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

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

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

(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.

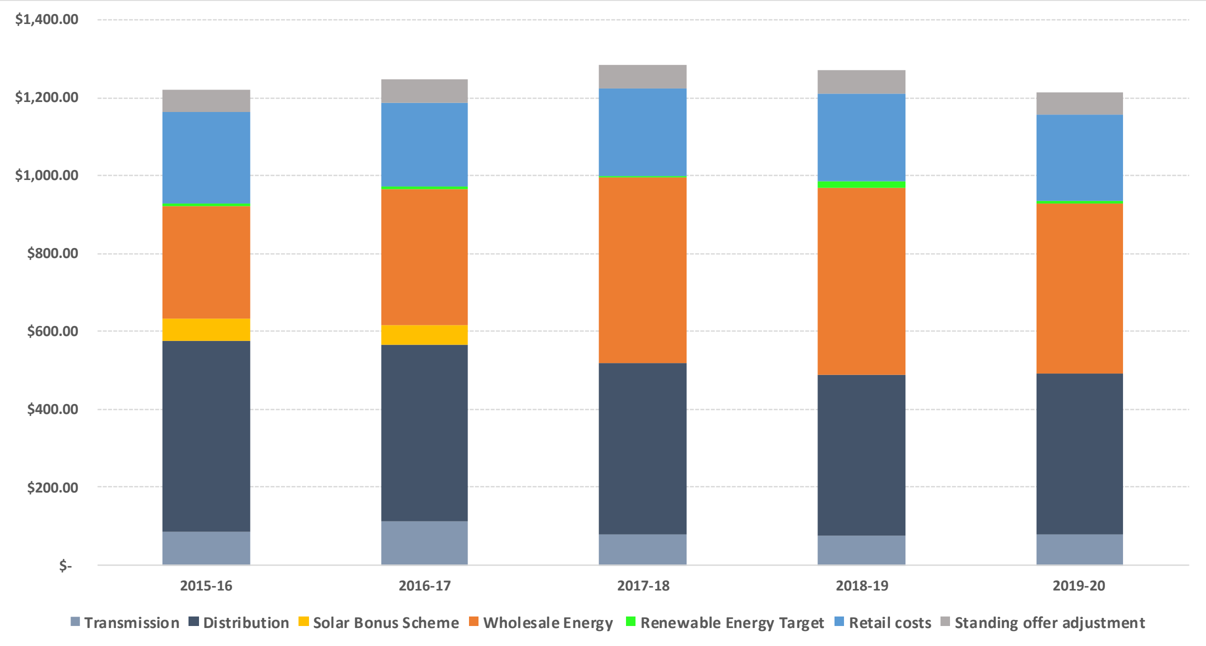
Electricity bill trends

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

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 2019–20.

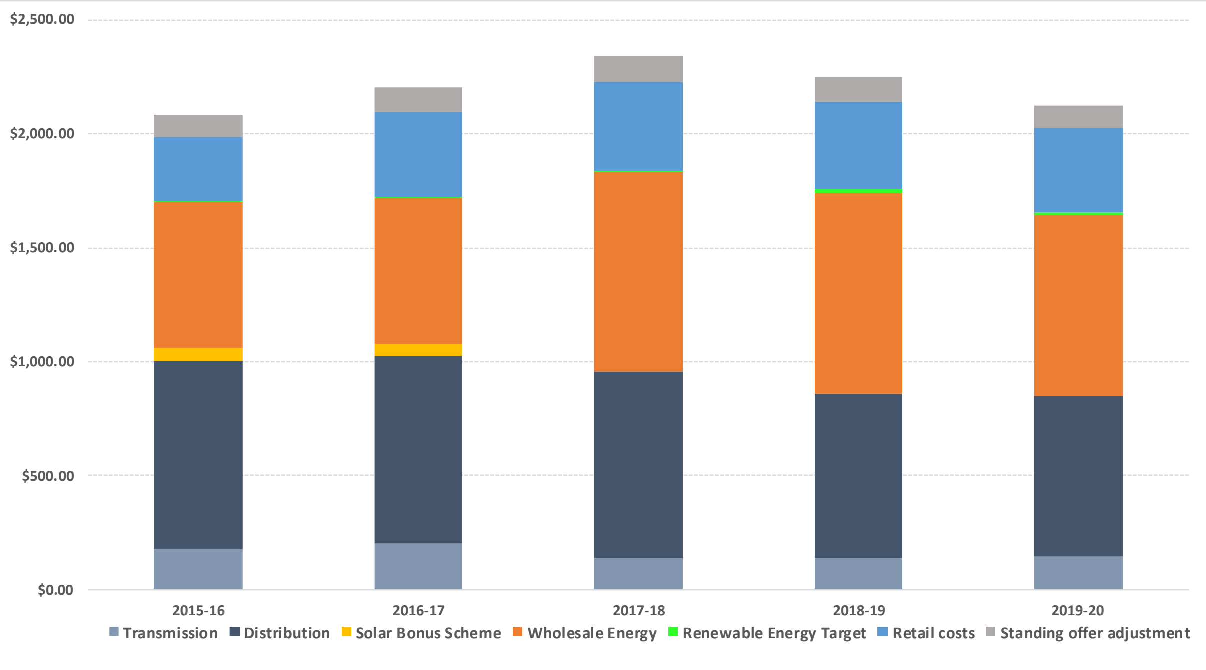
Figure 8 Typical residential customer—annual bill breakdown, 2015–2020



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

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 final 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 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 because of various 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 (NSLP)[23], 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.

[23] Energy usage measured by basic (accumulation) meters cannot be used in its raw format for wholesale settlement purposes in the NEM. This is because the NEM is settled on 30-minute trading intervals, whereas a basic meter reading is a single reading spanning a period of time, from a single day up to several months. Use of the NSLP for settlement purposes allows for conversion of readings from a basic meter reading into estimated energy consumption for each 30-minute trading interval. This process is described in detail in: AEMO, *Understanding Load Profiles Published from MSATS*, August 2013.

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 that 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 final 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 decision

Our final 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 were investigated.

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 its 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 customers on standard retail contracts who are 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.

In response to the QCA's draft determination, the Queensland Council of Social Service (QCOSS) offered support for the approach employed by the QCA in its draft determination, stating:

> We agree that the QCA's draft decision to continue to base notified prices for residential and small business customers on the costs of supply in south east Queensland is appropriate, because it is consistent with the Queensland Government's UTP, and it avoids the potentially large price increases associated with the other approaches.[24]

QCA decision

Our final 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 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

[24] QCOSS, sub. 35, attachment 1, p. 2.

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, the terms and conditions of such contracts often mean they offer fewer protections to customers.

In response to the draft decision, QCOSS noted it could not 'reproduce the QCA's calculation that the highest fees contained in a retail market offer that could be incurred by a customer are around $116.'[25]

QEUN recommended the permanent removal of the standing offer adjustment and headroom, stating:

> For many years households and businesses in regional Queensland have paid a 5% 'standing offer adjustment' or 'head room' charge to promote retail competition that does not exist in regional Queensland.[26]

QCA decision

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. While we agree quantifying these non-price terms is difficult, given the nature of the information available, we consider 5 per cent to be an appropriate value to apply for the standing offer adjustment. As a result, our final 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 discuss 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

[25] QCOSS, sub. 35, attachment 1, p. 7.
[26] QEUN, sub. 39, p. 5.

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.

In response to the QCA's draft decision on large business customer notified prices, Cotton Australia rejected the inclusion of a headroom charge, stating that:

> (1) The provision of a 'headroom' charge is to allow retailers to offer discounts, to help develop an atmosphere of competition. In the Ergon Network area there is no effective competition for the vast majority of users. Therefore, making the 'headroom' charge redundant.
>
> (2) Competition should be funded by innovation and efficiency, not by artificial inflation of the price. The application of a 5% headroom charge is no different to a retailer increasing prices by 5% one day, so it can offer a 5% discount the next.[27]

QEUN also called for the headroom charge to be removed (see section 6.3).

QCA decision

Our final 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 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.

[27] Cotton Australia, sub. 21, p. 5.

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.[28] *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 final determination on network service charges.

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. The network cost components for the final determination are based on the network pricing approved by the AER on 15 May 2019.

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

The process for determining network costs has three key stages:

Decide level of network costs

- the overall level (magnitude) of network service charges to apply

Decide tariff structures to apply

- the basis on which network costs are recovered from customers

Calculate tariff component

- using cost and tariff structures decided, calculate network service tariffs to apply

The QCA's consideration of network costs is set out 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 final 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[29] 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.[30]

QCA decision

The QCA's 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

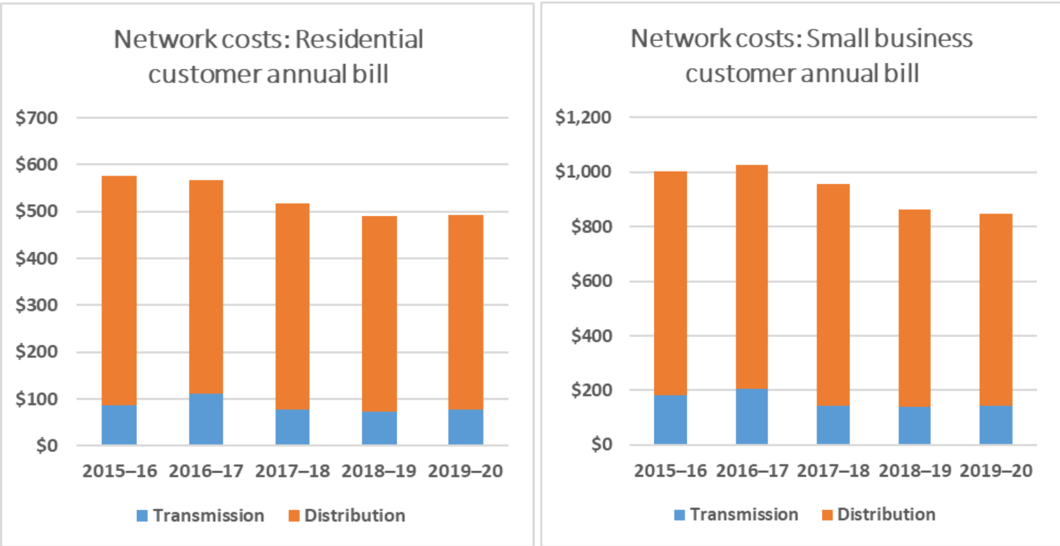
[29] Unmetered supply retail tariff referred to in this chapter excludes street lighting–related services.
[30] Origin Energy, sub. 8, p. 1; Energy Queensland, sub. 5, section 2.1; Queensland Consumers' Association, sub. 11, p. 1; Kalamia, sub. 6, p. 2; Canegrowers Isis, sub. 3, p. 1; QCOSS, sub. 10,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

regional customers. This would produce an outcome inconsistent with the government's UTP, including the ongoing arrangements for subsidising electricity costs for regional customers.

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 Energex network costs have not changed significantly from 2018–19. Based on the network pricing approved by the AER, overall network costs are around 1 per cent higher in 2019–20 for a typical residential customer[31] (around $3 more over the year), and 2 per cent lower for a typical small business customer[32] (around $17 less over the year) (see charts below).

Figure 10 Network costs—Residential and small business customers



Energy Queensland advised that:

- the slight increase in Energex network charges for the residential flat-rate tariff is primarily due to higher transmission charges
- the small reduction in Energex network charges for the small business flat-rate tariff can be mainly attributed to a reduced allocation of distribution costs to the small business customer group.

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[33], 41[34])

[31] A typical residential customer on tariff 11.
[32] A typical small business customer on tariff 20.
[33] Excluding street lighting (tariff 71).

- 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[35], stakeholders broadly supported using the approach outlined in the 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.[36]

Two matters that stakeholders raised require additional consideration. The first matter is about network 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.[37]
- QCOSS expressed broader concerns around the complexity of the tariff structure and potential impacts (e.g. bill shock) on customers that could result. It said the trial should be extended and improvements made to ensure customers are no worse off, or are compensated for any detriments.[38]

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.[39]

Origin Energy suggested 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.[40]

[34] 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.
[35] Energy Queensland, sub. 5, section 2.1; Canegrowers Isis, sub. 3, p. 2; Kalamia, sub. 6, p. 2.
[36] Origin Energy, sub. 8, p. 2; Energy Queensland, sub. 5, section 2.1; Canegrowers Isis, sub. 3, p. 2.
[37] Energy Queensland, sub. 5, section 2.1; Energy Queensland, sub. 23.
[38] QCOSS, sub. 10, p. 3.
[39] Origin Energy, sub. 8, p. 4.
[40] Origin Energy, sub. 8, p. 4.

QCA decision

The QCA's 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. This approach 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 customers to reduce usage during peak periods. This approach 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 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[41]
- 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.

[41] 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 .

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.

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.[42]

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).

On this basis, the QCA's final 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 4 (section 3.4).

3.3 Large business, very large business and street lighting customers

For the 2019–20 price determination, the delegation directs us to consider, for large business customers[43], 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 HV 66 kV (High Voltage—66 kV).

Most stakeholders supported maintaining this approach.[44]

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.[45]

[42] Energy Queensland, sub. 5, supplemented by additional information provided on a confidential basis (including financial calculations related to the tariff adjustment).
[43] 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.
[44] Energy Queensland, sub. 5, section 2.1.
[45] Canegrowers Isis, sub. 3, p. 2.

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.[46]

In addition, based on its latest analysis, Energy Queensland advised that among the non-site-specific network tariffs, the CAC standard network tariff HV 66 kV is the closest to cost reflectivity for ICCs on a network level. Therefore, we have decided to base the ICC retail tariff on the CAC standard network tariff HV 66 kV.

QCA decision

The QCA's 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.

[46] Canegrowers Isis, sub. 3, p. 2.

3.4 Summary of final 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)
  - tariff 15 (the lifestyle tariff) (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	48.800	8.424	
Tariff 20—Business (flat rate)	8500	66.200	8.801	
Tariff 31—Night rate (super economy)	9000		6.087	
Tariff 33—Controlled supply (economy)	9100		6.401	
Tariff 41—Low voltage (demand)[b]	8300	459.900	0.804	18.943
Tariff 91—Unmetered	9600		6.605	

a *Charged per metering point.*

b *The kVA equivalent demand charge for tariff 41 is $17.232/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)	37.258	41.467	5.182		
Tariff 22A—Business (seasonal time-of-use)	66.200	39.252	7.499		
Tariff 14—Residential (seasonal time-of-use demand)	6.350		1.726	50.852	7.303
Tariff 24—Business (seasonal time-of-use demand)	6.949		2.345	69.154	6.949

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	13.760	29.389	45.018	60.647	76.276	1.708	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—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	4029.100		1.343		32.590
Tariff 45—Over 100 MWh medium (demand)	EDMTT1	13534.300		1.343		24.274
Tariff 46—Over 100 MWh large (demand)	EDLTT1	35485.100		1.319		19.873
Tariff 50—Seasonal time-of-use (demand)	ESTOUDCT1	3114.000	1.024	3.251	59.972	10.384
Tariff 71—Street lighting[b]	EVUT1	0.500		15.646		

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	21965.900		1.305	9.209	3.929	2.388	4.000
Tariff 51B—Over 4 GWh high voltage (CAC 33kV)	EC33T1	15400.900		1.305	9.209	4.846	2.474	4.000
Tariff 51C—Over 4 GWh high voltage (CAC 22/11kV Bus)	EC22BT1	13986.900		1.309	9.209	5.621	2.999	4.000
Tariff 51D—Over 4 GWh high voltage (CAC 22/11kV Line)	EC22LT1	13178.900		1.326	9.209	11.096	6.050	4.000
Tariff 52A—Over 4 GWh high voltage (CAC STOUD 33/66kV)	EC66TOUT1	9845.900	0.884	1.254	9.209	6.181	11.000	4.000
Tariff 52B—Over 4 GWh high voltage (CAC STOUD 22/11kV Bus)	EC22BTOUT1	9845.900	0.888	1.258	9.209	4.336	41.435	4.000
Tariff 52C—Over 4 GWh high voltage (CAC STOUD 22/11kV Line)	EC22LTOUT1	9845.900	0.905	1.275	9.209	8.026	72.333	4.000
Tariff 53—Over 40 GWh high voltage (ICC)[a]	EC66T1	21965.900		1.305		3.929	2.388	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 have 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 most 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 final report, which also responds to issues around energy costs raised in stakeholder submissions.[47]

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 –$1,000 to $14,500 per megawatt hour (MWh).[48]

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

- pursuing a hedging strategy by purchasing financial derivatives[49]—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[50] to estimate energy costs and has been endorsed by the Australian Energy Market Commission (AEMC) in its 2013 advice on best practice retail regulation.[51]

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[47] ACIL Allen, *Estimated Energy Costs 2019–20 Retail Tariffs*, final report prepared for the QCA, May 2019, chapter 3.

[48] 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.

[49] 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.

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

[51] AEMC, *Advice on Best Practice Retail Price Regulation Methodology*, final report, September 2013.

For the 2019–20 price determination, we engaged ACIL Allen to estimate wholesale energy costs of customers for whom prices are 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[52] 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—that capture the consumption profiles of customers on retail tariffs 31 and 33 respectively.

4.1.1 Submissions

In its submission to the QCA, Origin Energy[53] 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.[54]

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.[55]

QCOSS[56] supported using a market hedging approach to estimate wholesale energy costs.

In its submission on the draft determination, Energy Queensland noted:

> Energy Queensland considers that ACIL Allen's spot price forecast requires further consideration on the impact of roof top solar photovoltaics (PV) and increasing generation from new utility-scale solar PV on prices in the middle of the day. Energy Queensland agrees with the trade

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[52] 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.

[53] Origin Energy, sub. 8.

[54] Energy Queensland, sub. 5.

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

[56] QCOSS, sub. 35.

> weighted contract pricing methodology used by ACIL Allen in its modelling and we have been able to replicate the results. However, we suggest consideration be given to the following differences which were identified when Energy Queensland attempted to replicate the net hedged price outcome.
>
> During the middle of the day, as spot prices depress due to solar PV generation, retailers may be subject to negative contract-for-difference payments as a consequence of the contract strike price being greater than the spot price. Energy Queensland requests further information on the wholesale energy costs used in the Draft Determination to adequately account for this scenario.
>
> We also note that while there is adequate information provided at the top of the price duration curve (i.e. price volatility), more information is required at the bottom of the curve (i.e. lower prices). Given the increasing incidence and changing timing of low pool prices in the Queensland market, Energy Queensland requests more detail to demonstrate how this development has been captured in determining pricing outcomes.[57]

As Energy Queensland indicated, the development of utility-scale solar photovoltaic in Queensland during 2019–20 will suppress wholesale spot prices during daylight hours. ACIL Allen's analysis demonstrated that, relative to actual spot prices from 2016–17 to 2018–19, the simulated spot prices during daylight hours for 2019–20 are lower in value and in terms of volatility. The simulated prices during daylight hours tend to be lower than the trade-weighted base and peak contract prices and therefore a retailer will be subject to negative contract for difference payments during these periods. These negative payments are accounted for by ACIL Allen's hedge model as a cost incurred by retailers while pursuing a hedging strategy using financial derivatives.

However, this phenomenon is not something new. In our earlier price determinations, there were occasions when the simulated spot prices were below their corresponding trade-weighted contract prices, but that was typically during the 1 am to 4 am period (when demand was at its lowest) instead of during daylight hours. What has changed, is the propensity for low spot price outcomes to occur and their timing, as periods with low spot prices are no longer constrained predominantly to periods between 1 am and 4 am. These issues are addressed in greater detail in chapter 3 of ACIL Allen's final report.

4.1.2 Overview

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[58] market data. A detailed explanation of how wholesale energy costs were estimated is in chapter 4 of ACIL Allen's final report.

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

[57] Energy Queensland, sub. 23.

[58] 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/.

committed to enter the Queensland market. ACIL Allen attributed the projected decrease in price volatility to the expected entry of renewable generation and the Queensland Government's directive to establish CleanCo[59], which will operate from 1 July 2019. The key impact of CleanCo on wholesale energy costs is expected to arise from 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[60] (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[61] 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 10.03 per cent to $89.16/MWh for the Energex NSLP
- decrease by 14.29 per cent to $75.58/MWh for the Ergon NSLP
- increase by 5.96 per cent to $64.91/MWh for the Energex CLP 9000 (retail tariff 31)
- decrease by 7.39 per cent to $72.85/MWh for the Energex CLP 9100 (retail tariff 33).

[59] The Queensland Government 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.

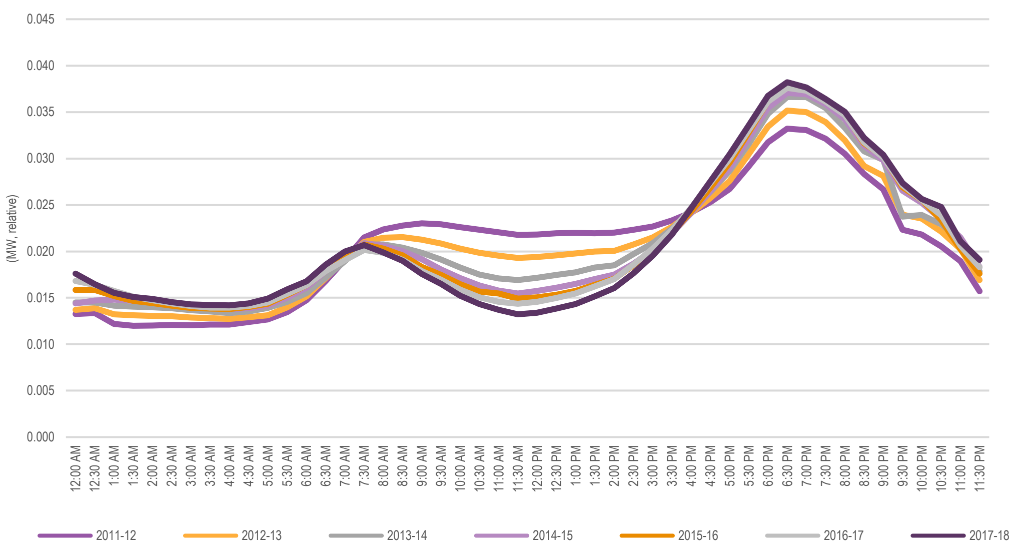
[60] The CleanCo generation portfolio consists of the Wivenhoe pumped storage facility, Barron Gorge, Kareeya and Koombooloomba hydro generators, and the Swanbank E gas-fired power plant.

[61] 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.

4.1.3 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 11 and 12). More electricity from the grid is consumed during peak periods on the Energex NSLP 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.

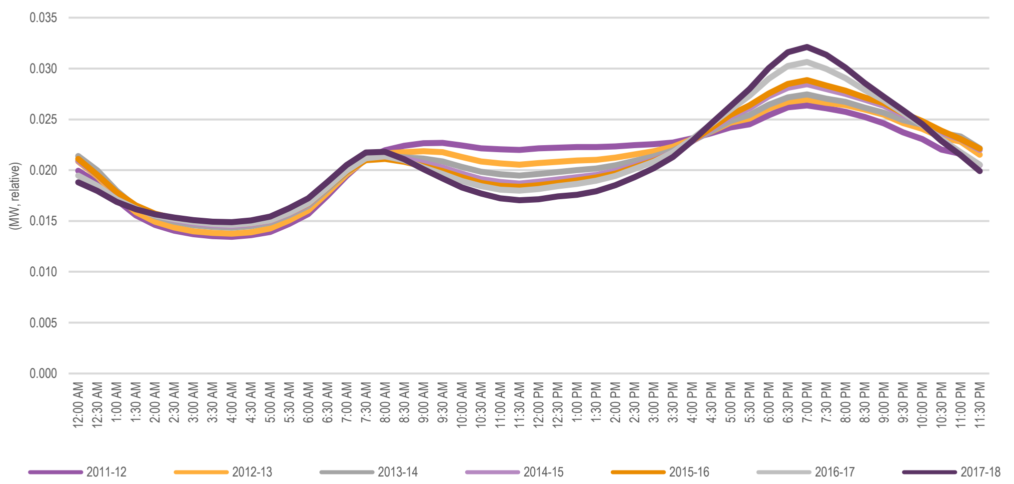
Figure 11 Energex NSLP



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, May 2019.

Figure 12 Ergon NSLP

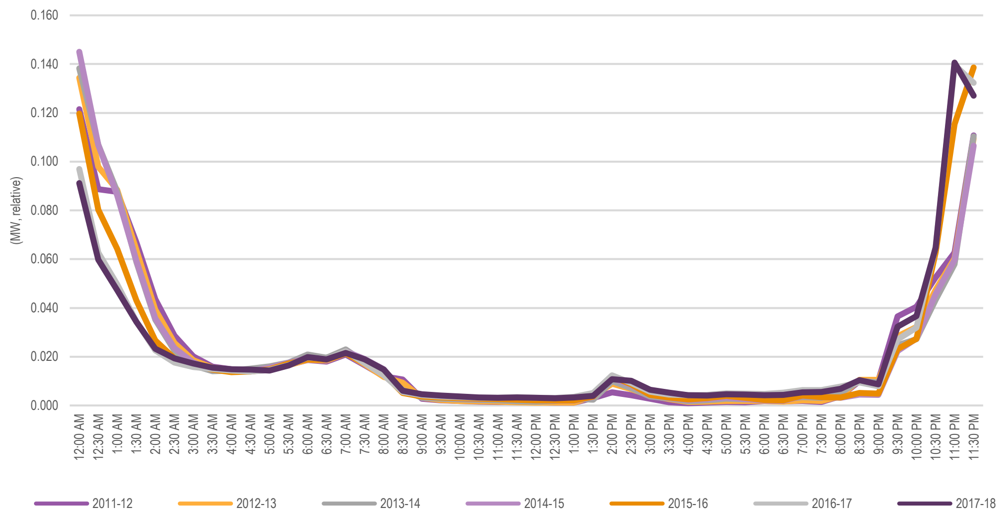


Note: 'Relative MW' means the annual loads for each profile have been scaled so they add up to one. This removes differences in absolute scale between the different profiles and changes in absolute size over time.

Source: ACIL Allen, May 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 13 and 14 show the Energex CLPs.

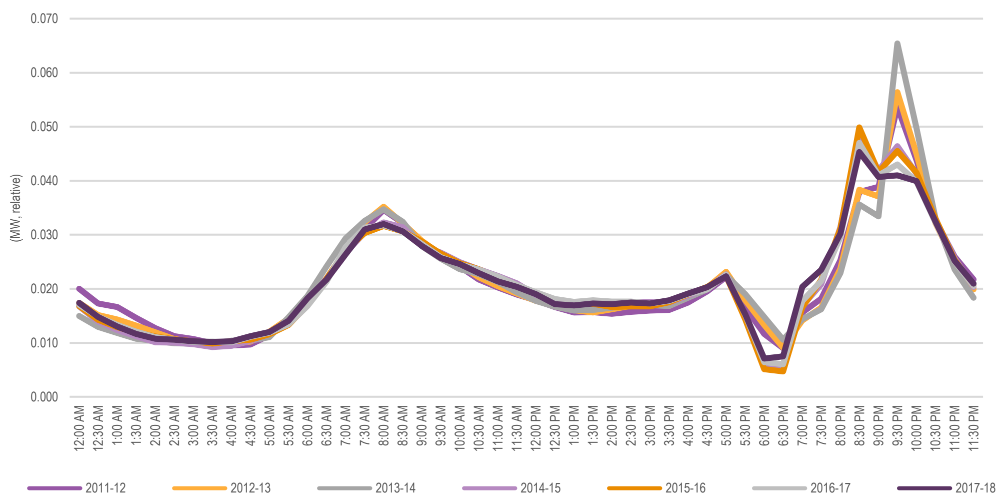
Figure 13 Energex CLP for retail tariff 31



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, May 2019.

Figure 14 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, May 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.

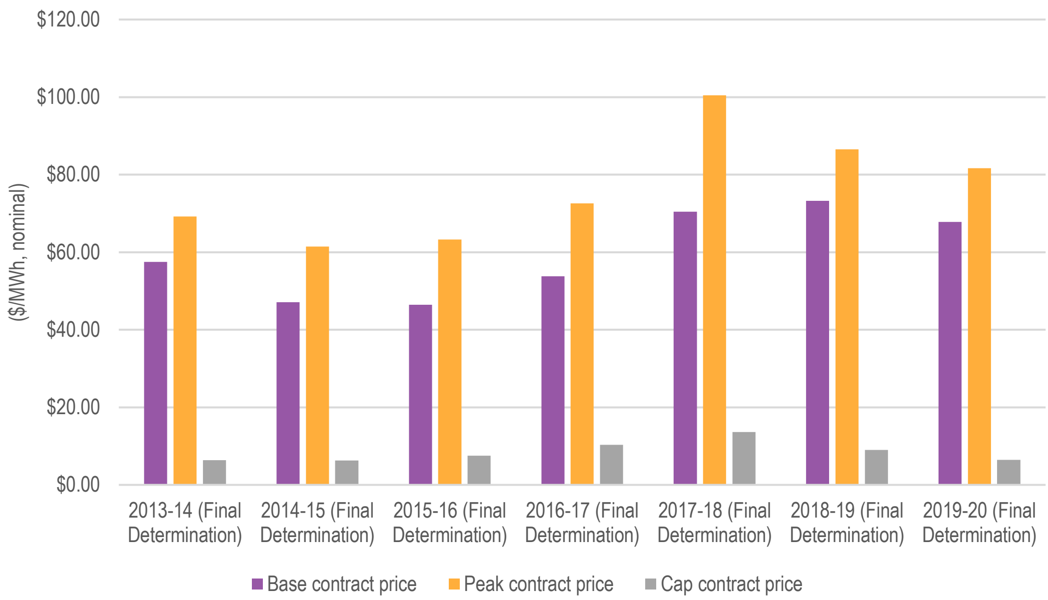
4.1.4 Estimating contract prices

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 10 April 2019. More details on ACIL Allen's approach are available in chapter 4 of its final 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 $5.40/MWh for base contracts
- decreased by about $4.75/MWh for peak contracts
- decreased by about $2.58/MWh for cap contracts.

Figure 15 Annualised quarterly electricity futures contract prices ($/MWh), 2019–20 final determination and previous final determinations



Source: ACIL Allen, May 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.

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.

4.1.5 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.

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[62] of around 1 per cent.

However, as part of a smaller generation portfolio of CleanCo, 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 determination.

4.1.6 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.[63] 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[64] will decrease by 25.6 per cent in south east Queensland.[65] 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

[62] 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.
[63] AEMC, *2018 Residential Electricity Price Trends Review*, final report, December 2018.
[64] 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.
[65] 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 ACIL Allen arrived at by using a market-hedging approach.

  - 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. This approach, in effect, incorporates the timing 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.

4.1.7 QCA decision

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 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 have decided 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 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	$89.16	–10.03	–$9.94
Energex CLP 9000	31	$64.91	5.96	$3.65
Energex CLP 9100	33	$72.85	–7.39	–$5.81
Ergon Energy NSLP—SAC demand and street lighting	44, 45, 46, 50, 71	$75.58	–14.29	–$12.60
Ergon Energy NSLP—high voltage—CAC and ICC	51A, 51B, 51C, 51D, 52A, 52B, 52C, 53	$75.58	–14.29	–$12.60

Source: ACIL Allen, May 2019.

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[66] and ancillary services charges
- prudential capital costs.

4.2.1 Renewable energy target costs

The RET scheme, consisting 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.[67]

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.

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 …

[66] The NEM management fees were formerly referred to as the NEM participation fees.
[67] 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.[68]

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.[69]

ACIL Allen maintains 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 final report, ACIL Allen estimated LRET costs using an approach broadly consistent with the previous determination. It estimated the implied RPP for 2020 using the mandated LRET target for 2020 and its estimate of electricity consumption in 2020. This is a departure from ACIL Allen's previous methodology of estimating the implied electricity consumption using the latest non-binding SRES data published by the CER. ACIL Allen advised that this change in approach is necessary in order to ensure consistency between the electricity consumption used to derive the implied RPP and the electricity demand growth used in the spot market modelling.

ACIL Allen has provided a detailed explanation of its calculations in chapter 4 of its final 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 projects, 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 \$9.38/MWh for all retail tariffs—a reduction of \$4.34/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.[70] 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.

[68] Origin Energy, sub. 8.
[69] Energy Queensland, sub. 5.
[70] AEMC, *2018 Residential Electricity Price Trends Review*, December 2018.

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 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 consisting of several brokers and trading platforms, and as such, it 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 decision

The QCA considers that ACIL Allen's market-based approach, using LGC forward price information provided by TFS, 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 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.[71] 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.[72]

To address the issues raised by Origin Energy, ACIL Allen updated the CER's non-binding STPs for the draft determination, by using data up to 30 November 2018 to incorporate the recently observed strong uptake in small-scale energy systems. This approach reduced the variation in the SRES cost estimates between the draft and final determinations, when the CER updated the STPs in March 2019.

In its final report, ACIL Allen estimated SRES costs using a similar approach as in 2018–19. ACIL Allen estimated that the SRES cost for 2019–20 would be $7.26/MWh for all retail tariffs—an increase of $1.42/MWh compared to the 2018–19 final determination.

SRES costs have increased substantially since the 2018–19 final determination, by 24.3 per cent. This substantial increase is due to the CER increasing the STPs for 2019 and 2020. The higher STPs mean that retailers must now purchase a greater number of STCs to fulfil their obligations under the SRES. The CER advised that the increase in the STPs reflects a significant spike in the volume of STCs created—driven primarily by a higher than expected uptake of rooftop solar photovoltaic.

For the 2018–19 price determination, we used the non-binding STP for 2019 to determine the SRES costs for the second half of that financial year. As the CER has updated and increased the STP for 2019, we need to apply a cost pass-through to allow retailers to be compensated for the under-recovered SRES costs for 2018–19 (see Chapter 6).

QCA decision

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 notes that maintaining a consistent approach for 2019–20 will also provide certainty to stakeholders.

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

[71] 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).
[72] Origin Energy, sub. 8.

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.

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[73] observed over the preceding 52 weeks.

In its final 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.[74]

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.[75] ACIL Allen estimated that ancillary services costs would be $0.37/MWh for 2019–20.

QCA decision

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 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

[73] AEMO provides data on weekly settlements for ancillary service payments in each interconnected region within the NEM.
[74] ACIL Allen, May 2019, chapter 4.
[75] 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.

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[76] 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[77], 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.

In its final report, ACIL Allen estimated prudential costs using an approach that is consistent with its 2018–19 approach.[78]

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 $1.51/MWh respectively.

QCA decision

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 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 2019–20

Tables 8 and 9 set out the final 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	*2018–19*	*2019–20*	*Change from 2018–19*	
	$/MWh		*%*	*$/MWh*
LRET	$13.72	$9.38	–31.6%	–$4.34
SRES	$5.84	$7.26	24.3%	$1.42
NEM fees	$0.53	$0.63	18.9%	$0.10
Ancillary services	$0.43	$0.37	–14.0%	–$0.06
Prudential capital	$2.95	$2.18	–26.1%	–$0.77
Total	**$23.47**	**$19.82**	**–15.6%**	**–$3.65**

Note: Totals may not add due to rounding.

Source: ACIL Allen, May 2019.

[76] Energy Queensland, sub. 5.
[77] See Chapters 1 and 2.
[78] ACIL Allen, February 2019, chapter 4.

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

Cost component	*2018–19*	*2019–20*	*Change from 2018–19*	
	$/MWh		*%*	*$/MWh*
LRET	$13.72	$9.38	–31.6%	–$4.34
SRES	$5.84	$7.26	24.3%	$1.42
NEM fees	$0.53	$0.63	18.9%	$0.10
Ancillary services	$0.43	$0.37	–14.0%	–$0.06
Prudential capital	$2.09	$1.51	–27.8%	–$0.58
Total	**$22.61**	**$19.15**	**–15.3%**	**–$3.46**

Note: Totals may not add due to rounding.

Source: ACIL Allen, May 2019.

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 2019–20 transmission and distribution loss factors published by AEMO in a manner that aligns with AEMO's settlement process. These loss factors are:

- the average energy-weighted transmission loss factor—estimated by ACIL Allen, using the loss factors and energy consumed at each of the Transmission Node Identities (TNI) provided by AEMO
- the distribution loss factor published by AEMO.

QCA decision

The QCA's decision is to accept ACIL Allen's advice on this matter and its loss factor calculations (Table 10).

4.4 Total energy cost allowances for 2019–20

Table 10 summarises the QCA's decision on energy cost allowances for each retail tariff for 2019–20. To be consistent with the UTP[79], we have decided 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

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	$89.16	$19.82	1.065	$116.06	11.606	–10.84%
Energex CLP 9000	31	$64.91	$19.82	1.065	$90.24	9.024	0.29%
Energex CLP 9100	33	$72.85	$19.82	1.065	$98.69	9.869	–9.01%
Ergon Energy NSLP—SAC demand and street lighting	44, 45, 46, 50, 71	$75.58	$19.15	1.024	$97.00	9.700	–16.69%
Ergon Energy NSLP, high voltage—CAC and ICC	51A, 51B, 51C, 51D, 52A, 52B, 52C, 53	$75.58	$19.15	0.987	$93.50	9.350	–15.77%

Note: Totals may not add due to rounding.

Source: ACIL Allen, May 2019.

[79] 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 service 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 (the 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.[80] 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.

QCOSS supported indexing retail costs downward to 'reflect increased efficiencies'.[81] QCOSS considered that evidence from publicly available retailer information provided in previous years' submissions proved that efficient costs were falling. QCOSS also submitted 'that up-to-date calculation of efficient retail costs based on current efficient costs, and not indexation of previous costs, must be carried out as a matter of urgency for the setting of notified prices for 2019-20, and for future years'.[82]

The QEUN argued that, as there is limited competition in regional Queensland, customer acquisition and retention costs (CARC) should be removed from retail cost allowances.

[80] 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.
[81] QCOSS, sub. 35, attachment 1, p. 5.
[82] QCOSS, sub. 35, attachment 1, p. 6.

Based on advice from Sapere Research Group (Sapere), Canegrowers argued that the QCA should revise the retail cost allowance downwards:

> The market benchmark used by QCA incorporates non-existent costs reflected in NEM retail prices in markets that are no longer subject to price regulation, and where there is no effective market monitoring. There is evidence from a number of careful studies that retail prices significantly exceed efficient costs.[83]

Sapere went on to say that a final decision by QCA to set notified prices 'well in excess of efficient costs would be inconsistent with Section 3 of the Act'.[84] Sapere recommended that the QCA use the benchmark estimate used under the previous methodology, rolled forward by CPI.

QCA decision

Given the uncertain policy environment at present, and noting the views expressed by Energy Queensland, Origin Energy and the Queensland Consumers' Association, the QCA considers that the retail cost allowances established in 2018–19 are an appropriate starting point for establishing the 2019–20 retail cost allowances.

The QCA considered the information previously provided by QCOSS, which showed public statements by AGL and Origin Energy that indicated slightly lower cost to serve per customer account figures across Australia but also showed increases in the cost of acquiring customers. As retailers serve a varying mixture of new and existing customers, it is not clear this data establishes that overall retail costs are likely to fall in Queensland in 2019–20.

The QCA considers there may be merit in revisiting retail cost benchmarks in the near future. However, for the 2019–20 pricing process, we considered the policy uncertainty to be too great to produce reliable retail cost estimates. In addition, in order to provide natural justice for stakeholders, a change of methodology for 2019–20 of that magnitude would require further consultation, which would not be possible under the tight timelines for this pricing determination.

The AER also recently assessed retail costs in the wider energy market in its final determination on default market offer (DMO) prices for 2019–20. The AER concluded:

> [W]e expect retail costs will remain constant. We have adjusted this cost component by changes in CPI.[85]

The QCA has considered the comments by QEUN regarding CARC. While it is highly unlikely that Ergon Retail will incur the same level of CARC for residential and small business customers as a retailer in south east Queensland, the actual CARC incurred by Ergon Retail are irrelevant to setting prices that reflect the government's chosen UTP benchmark. This is because this benchmark references retail costs in the competitive south east Queensland market, which include CARC. Removing competition costs from retail costs would result in notified prices that are inconsistent with the UTP.

The QCA has also considered Canegrowers' position, and the advice provided by Sapere, that retail cost allowances should be reduced and the QCA should consider using the previous benchmarks established by IPART in 2013, escalated by inflation, rather than the more up-to-date benchmarks established by the QCA in 2016. The reasoning behind this suggestion is that Canegrowers and Sapere consider that the market benchmarks used by the QCA contain excess

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[83] Canegrowers, sub. 18, p. 1.
[84] Canegrowers, sub. 18, attachment 1, p. 9.
[85] AER, *Final Determination—Default Market Offer Prices 2019–20*, April 2019, p. 59.

margins associated with deregulated markets, and therefore do not reflect the actual cost of supply as contemplated by section 90(5) of the Electricity Act. However, the QCA is setting small customer retail tariffs based on the UTP, rather than actual costs.

As discussed in Chapter 2, the QCA must weigh up the requirements of section 90(5)(a)(i) of the Electricity Act, which requires the QCA to have regard to the actual costs of supply, against matters in the Minister's delegation, which the QCA must have regard to under section 90(5)(a)(iii) of the Electricity Act. In short, the QCA must choose between setting prices based on the actual cost of supply or according to the Queensland Government's UTP, which provides that, 'wherever possible, customers of the same class should pay no more for their electricity, regardless of their geographic location'.[86] Setting notified prices based on the UTP results in electricity prices below the costs of supply for most regional customers.

In order to reflect the government's UTP in notified prices, the QCA must estimate the retail costs of retailers in south east Queensland. The QCA considers the market-based estimates established in 2016 are a more accurate reflection of retail costs than the benchmarks established by IPART in 2013. The benchmarks established by IPART were based on the costs of recently privatised standard retailers in 2013, and the QCA considers the benchmarks established based on competitive retail markets in 2016 will be more reflective of the likely costs for retailers in 2019–20.

For 2019–20, the QCA will adjust fixed retail cost allowances by forecast CPI, and 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.

The QCA will consider revising retail cost benchmarks in the 2020–21 determination, if again delegated the task of setting notified prices.

Residential and small business customers

For residential and small business customers, we have maintained retail cost allowances in real terms by:

- adjusting the fixed retail cost allowances (that were estimated for 2018–19) 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 retail cost allowances, including regulatory fees, for regulated small customer tariffs in 2019–20.

[86] Part 5(b) of the terms of reference. See Appendix A.

[87] We adopted a CPI of 1.625 per cent, equal to the average of forecast inflation at June 2019 and June 2020. See Reserve Bank of Australia, *Statement on Monetary Policy*, February 2018, table 5.1, p. 66.

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	37.243		2.257		
T12A	37.243	5.981	1.892		
T14	37.243		1.503	5.731	0.823
T31			1.703		
T33			1.834		

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	52.787		2.612		
T22A	52.787	6.510	2.445		
T24	52.787		1.786	8.852	0.889
T41	52.787		1.589		2.425
T91			2.331		

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	11.336	11.336	11.336	11.336	11.336	1.501	0.930

Large business customers

Tables 14 and 15 show 2019–20 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], maintained variable retail cost allocators at 6.0445 per cent, and updated regulatory fees.

[88] We adopted a CPI of 1.625 per cent, equal to the average of forecast inflation at June 2019 and June 2020. See Reserve Bank of Australia, *Statement on Monetary Policy*, February 2018, table 5.1, p. 66.

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	377.785		0.667		1.970
T45	1039.185		0.667		1.467
T46	2643.685		0.666		1.201
T50	340.217	0.648	0.783	3.625	0.628
T71			1.532		

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	2616.960		0.644	0.557	0.237	0.144	0.242
T51B	2616.960		0.644	0.557	0.293	0.150	0.242
T51C	2616.960		0.644	0.557	0.340	0.181	0.242
T51D	2616.960		0.645	0.557	0.671	0.366	0.242
T52A	2616.960	0.619	0.641	0.557	0.374	0.665	0.242
T52B	2616.960	0.619	0.641	0.557	0.262	2.505	0.242
T52C	2616.960	0.620	0.642	0.557	0.485	4.372	0.242
T53	2436.108		0.644		0.237	0.144	0.242

5.2 Large customer metering charges

Submissions

Energy Queensland was concerned that, while consistent with the treatment of customers in south east Queensland, establishing a separate metering charge for large customers consuming under 750 MWh per annum may cause confusion, as the classification would differ from their network classification.

QCA decision

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. The data was averaged to produce cost estimates for each large customer type.

The QCA notes Energy Queensland's point about customer confusion. However, in contrast to 2018–19, the latest data provided by retailers reported that their metering 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 final decision has focused on consistency and certainty in treatment of matters where this is appropriate. In addition, the QCA's final 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.

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

6.1 Standing offer adjustment—residential and small business customer tariffs

6.1.1 Considerations for this review

Key considerations for the QCA in determining the notified prices are described in Chapter 1, 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 undertook. 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] Paragraph 5(b) of the Terms of Reference, Minister's Delegation (Appendix A).

  - 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.

Structure of the QCA's review

The standing offer adjustment is discussed as follows:

Rationale for an adjustment → The basis for the adjustment → The level and impact of the adjustment

Stakeholders have commented on issues about the AER's review on the default market offer (DMO). We have addressed these matters in a separate section (see section 6.2).

6.1.2 Rationale for an adjustment

The QCA has been delegated the task of determining notified prices for customers in regional Queensland.[90]

Under the Electricity Act, notified prices need to reflect the price a retailer may charge its 'standard contract customers'[91] and, consistent with the government's UTP, this means the expected level of standing offer contract prices should reflect prices a retailer may charge in south east Queensland.

For 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.[92]

Stakeholder comments

Stakeholders' comments on various elements of the standing offer adjustment were mixed. Some stakeholders considered an adjustment should not be made[93], whereas others said incorporating an adjustment would be consistent with previous determinations and should be maintained.[94]

In response to the QCA's draft decision to maintain a standing offer adjustment:

- QCOSS said it did not agree that a standing offer adjustment should be included in notified prices. It recognised the requirement to set notified prices in accordance with legislation and the Minister's delegation, but expressed disappointment that the standing offer adjustment

[90] Customers in Queensland other than those in the Energex distribution area—e.g. outside of the south east Queensland region.

[91] 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.

[92] Delegation and cover letter (Appendix A), the executive summary and Chapter 2.

[93] Canegrowers Isis, sub. 3, p. 2.

[94] Origin Energy, sub. 8, p. 3.

is still included in regulated prices. QCOSS also urged the government to consult with stakeholders on the terms of the delegation for notified prices in 2020–21.[95]

- QEUN recommended that the Queensland Government reject the QCA's draft notified prices and instead reduce power bills by 10 per cent for households, including by permanently removing the 5 per cent standing offer adjustment and providing more transparency around the UTP arrangements and calculations.[96]
- Other stakeholders urged the QCA to remove the standing offer adjustment in order to reduce electricity prices, among other reasons because high electricity costs are severely impacting the living conditions of people in regional Queensland.[97]

QCA analysis and final determination

The QCA acknowledges stakeholder concerns—noting that many stakeholders are members of regional communities and, as a means of reducing their electricity bills, have a strong preference for removing the standing offer adjustment.

Other stakeholders also consider the adjustment to notified prices, currently in the form of the standing offer adjustment, should not be made. For the most part, these stakeholders consider there is no value attached to the terms contained in standard contracts; and they have no choice but to contract in this manner and, as a result, are opposed to notified prices being subject to increases (on dollar terms) on this basis.

The QCA accepts these concerns are genuine and are expressed in order to assist the QCA's review. A number of individuals, as well as industry groups, have chosen to participate in this process and provide comments and views to the QCA as part of this review, and are keen to see a reduction in electricity prices.

The concerns raised by stakeholders go to the heart of matters beyond those the QCA is able to consider in its review. The framework in which the QCA operates sets boundaries for considering how notified prices should be set. It does not unlock the QCA's investigative and decision-making powers to assess broad industry-related concerns (electricity costs and affordability in regional Queensland) and implement measures proposed by stakeholders aimed at addressing these concerns (e.g. reducing regional electricity prices). As such, while the QCA acknowledges these concerns, they arise in connection with the overarching framework development and operation (legislation and policy), rather than how a particular task is performed within this framework (the QCA's role in setting notified prices).

For these reasons, the QCA maintains the view that an adjustment, currently in the form of the standing offer adjustment, is necessary to incorporate into notified prices. This component is the means by which it is possible for the QCA to ensure notified prices are set in a manner that is consistent with:

- prices a retailer may charge its 'standard contract customers' in south east Queensland (as required by legislation[98])
- the government's UTP (as set out in the delegation and designed to ensure regional customers pay broadly the same prices as customers in south east Queensland).

[95] QCOSS, sub. 35, p. 2.
[96] QEUN, sub. 36, p. 3.
[97] P. Pollard, sub. 33, p. 1; E. Waters, sub. 43, p. 1.
[98] See section 90(1) of the Electricity Act.

Taken as a whole, the QCA considers incorporating the adjustment, along with each component used to build up the notified prices, reflects these requirements.

The QCA encourages stakeholders to consider alternative options and remains committed to considering these options if they are raised in future reviews. The QCA will consider any genuine alternatives that meet the needs of stakeholders in a better way, while ensuring consistency with the legislative and policy requirements within which the QCA operates.

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

The QCA has considered the basis on which the standing offer adjustment should be made. This section deals with the factors relevant to determining the value of the adjustment to include in notified prices as part of this review.

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).

Stakeholder comments

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.[99]
- 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 that 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.[100]
- 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 not having late payment fees).[101]
- A number of stakeholders mentioned the AER's review of the DMO and questioned whether this review could have implications for the QCA's process, retail prices and the operation of retail markets.[102] 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.[103] Other

[99] Energy Queensland, sub. 5, p. 10.
[100] Queensland Consumers' Association, sub. 11, p. 2.
[101] QCOSS, sub. 10, p. 2.
[102] Origin Energy, sub. 8, p. 1; Queensland Consumers' Association, sub. 11, p. 2; QCOSS, sub. 10, p. 3.
[103] Energy Queensland, sub. 5, pp. 12–13.

stakeholders said there were risks, and the AER's process creates uncertainties that may have implications for the QCA's process.[104]

In response to the draft determination, stakeholders provided some further comments about the basis of the adjustment:

- QCOSS said it was pleased the standing offer adjustment is no longer based on standing offer prices in the south east Queensland market. It said the basis for determining the factor should be more comprehensive and robust.[105]
- QEUN said there is no basis for the standing offer adjustment, given the lack of competition in the retail energy market—it is effectively a hidden tax paid to the government, allowing Ergon to increase its profits.[106]

QCA analysis and final determination

The QCA accepts it is necessary to incorporate an adjustment into notified prices and has considered all information available to determine an appropriate basis on which the adjustment should be made.

A number of different options are available. At the same time, it is also evident that, over time, new information or considerations may arise and may suggest an alternative method is more appropriate.

The revised approach considered in this review (based on the delegation directions) involves an assessment of the value of non-price factors. This differs from last year, when the approach involved an assessment of the standing offer contract prices and market contract prices. To the extent there was a difference, this reflected both price and non-price factors.

The revised approach appears to address some of the key concerns raised by the Queensland Consumers' Association and QCOSS, as it no longer focuses on price factors alone. 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 that may be considered as part of estimating the value, the data and other information used in the assessments remain the same. This means assessments do not allow for the level of transparency and reconciliation of the adjustment value that stakeholders may desire. For instance, QCOSS suggested the QCA should undertake a comprehensive and representative survey and/or some statistical analysis to ensure the basis for the adjustment was robust.

While the time required to undertake such analysis precludes such work being done for this review, we consider it may be possible to refine the approach further if we are delegated the task of determining notified prices for 2020–21. That said, there may also be considerable practical difficulties with implementing and interpreting the outputs of such work. Furthermore, the practical difficulties may extend further if input variables are unable to be agreed, and the

[104] Origin Energy, sub. 8, p. 1; Queensland Consumers' Association, sub. 11, p. 2; QCOSS, sub. 10, p. 3.
[105] QCOSS, sub. 35, p. 2.
[106] QEUN, sub. 36, p. 5.

outcome of these fluctuates over time and produces results difficult to reconcile (as was the case when linking the adjustment to standing offer prices in previous years).

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 clear from the stakeholder comments received on this matter.

While the standard contract 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).[107]

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.

6.1.4 An appropriate value

The QCA has considered the value to apply to the standing offer adjustment included in notified prices in 2019–20.

We have been directed to consider a value similar to the level of the adjustment made by the QCA in previous determinations (5 per cent), among other reasons because that value appropriately reflects the additional value afforded via protections contained in standard contract terms and conditions.

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

Stakeholder submissions

In the original submissions, stakeholders generally agreed that the level of the adjustment should be either the same as, 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.[108]
- 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.[109]

[107] ACCC, *Restoring electricity affordability and Australia's competitive advantage*, June 2018, p. 248.
[108] Canegrowers Isis, sub. 3, p. 2.
[109] Queensland Consumers' Association, sub. 11, p. 3.

- Origin Energy supported maintaining the standing offer adjustment at 5 per cent.[110]
- Energy Queensland supported retaining the standing offer adjustment at 5 per cent and considered this was consistent with the UTP.[111]

In response to the QCA's draft determination, QCOSS said the value of the adjustment should be low and less than the 'seemingly arbitrary' 5 per cent adjustment suggested by the Minister's letter to the QCA. It added that the QCA should undertake a comprehensive and representative survey and/or some statistical analysis to work out a robust value.[112]

QCOSS also attached a report to its submission from its consultant (Etrog Consulting), who said:

- It had not been able to reproduce the QCA's calculation that the highest fees contained in a retail market offer that could be incurred by a customer were around $116, and considered that some fees included in the QCA's calculations would be mutually exclusive.[113]
- It doubted that any customer would ever incur the maximum set of charges, and suggested the QCA should reconsider the upper bound value—based on a more realistic set of circumstances.[114]
- Using only non-zero values to determine the average dollar charges skews the average.[115]
- QCA should document its calculations in the interests of transparency, so as to enable stakeholders to reproduce the calculations more easily. QCA could also illustrate its considerations better by showing a form of scatter plot (possibly weighted by size of retailer).[116]

QCA analysis and final decision

Difficulties may arise in determining an appropriate value for the adjustment—given the nature of the information available, the extent to which both quantitative and qualitative aspects can be measured, and the relatively short timeframe in which the assessment must be made.

As such, the QCA has assessed this matter based on all relevant information available, including market data and observations; the 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 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.

[110] Origin Energy, sub. 8, p. 2.
[111] Energy Queensland, sub. 5, p. 10.
[112] QCOSS, sub. 35, p. 2.
[113] QCOSS, sub. 35, attachment 1, pp. 7–8.
[114] QCOSS, sub. 35, attachment 1, p. 8.
[115] QCOSS, sub. 35, attachment 1, p. 8.
[116] QCOSS, sub. 35, attachment 1, p. 8.

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, 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 reflected 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 that this information informs the assessment and supports a value of 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 (Figures 15 and 16), in which the dollar values represent the average charge for a particular fee type, where that fee is applied by retailers.[117]

In presenting the data on fees and charges, the QCA 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 (Figures 16 and 17) on the basis of a quarterly bill charge and on the basis of the annual bill (cumulative) charges.[118] 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.

[117] 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. Etrog's view was that using only non-zero values to determine the average dollar charges skews the average. However, as the purpose of the review is to assess what value retailers attach to standard terms and conditions (explicitly), the sample used must necessarily contain fees that retailers have explicitly valued separately to the cost of electricity supply.

[118] QCA, *SEQ retail market monitoring: July to September 2018*, October 2018, Table 50 and 51.

Figure 16 Summary of market offer fees and charges, residential customer

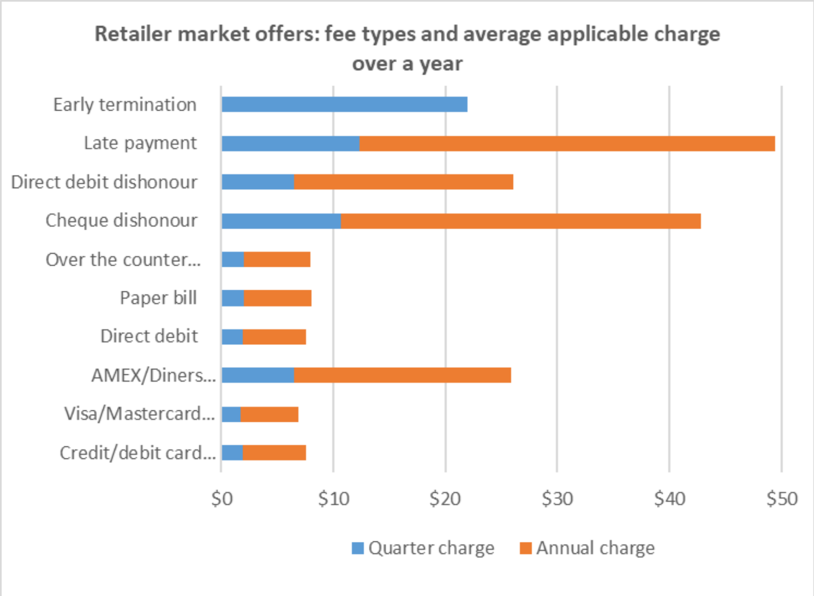
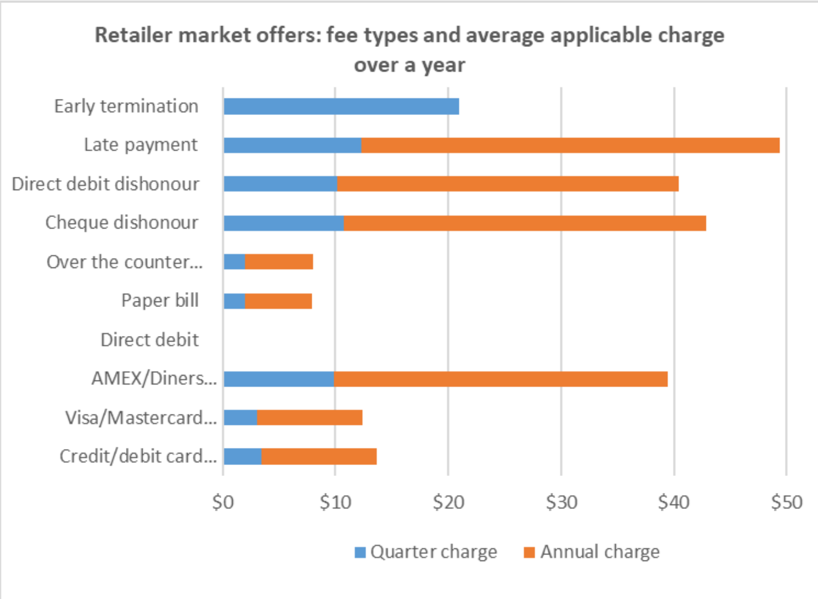


Figure 17 Summary of market offer fees and charges, small business customer



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, which represented 9.5 per cent of a median annual bill.
- For small business customers—market offers showed the highest charges that could be incurred by a customer were around $164, which represented 7.4 per cent of a median annual bill.[119]

[119] 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

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 to 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
- 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 that would vary based on individual customer circumstances)
- some fees included in the QCA's calculations are mutually exclusive, and it is unlikely that any individual customer would incur all of the charges, as noted by Etrog.

As a result, it is not possible to empirically determine a precise value—and while we do not propose to rely on such an approach at this time to empirically determine an appropriate value, we still consider it provides some guidance for developing the range of potentially acceptable values for the standing offer adjustment (given the data available and limitations identified).

As such, this information informs the range of potentially acceptable values and supports a value of less than 9.5 per cent as being appropriate to reflect the value of terms and conditions contained in standard contracts (accounting for the factors mentioned above).

Other information

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

The QCA is also satisfied that the value is 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, as 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

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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.

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.[120]

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.

While the timing for the 2019–20 final determination precludes further work being done at this time, it is possible to further develop the approach if the QCA is delegated the task of determining notified prices for 2020–21 (noting the practical difficulties with implementing and interpreting the outputs of such work discussed above).

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).

Final determination

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.

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.

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. As indicated above, the QCA acknowledges the shortcomings associated with the empirical data, but has used its regulatory judgement in considering all available information and determining that a standing offer adjustment of 5 per cent is reasonable.

[120] 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 for meeting all conditions was $75 for residential customers and $120 for small business customers.

The QCA acknowledges that this matter remains a contentious issue, and expects to investigate it further (including additional consideration of potential methodologies for ascertaining a robust value for a standing offer adjustment) if delegated the task of determining notified prices for 2020–21.

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 was directed to set a maximum DMO price for relevant network regions by 30 April 2019 (with prices to take effect from 1 July 2019).[121]

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 proposed a 'top-down' approach based on current market and standing offer prices to determine DMO prices.[122]
- 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.[123] 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.[124]
- QCOSS said the AER process is different to the QCA's process and may produce different outcomes, but it will consult government and regulators and raise any concerns that become apparent.[125]
- 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

[121] J Frydenberg (Treasurer, Australian Government) and A Taylor (Minister for Energy, Australian Government), letter to the AER, 22 October 2018, p. 1.
[122] Energy Queensland, sub. 5, p. 11.
[123] Queensland Consumers' Association, sub. 11, p. 2.
[124] Queensland Consumers' Association, sub. 11, p. 2.
[125] QCOSS, sub. 10, p. 2.

results that reflect the objective for a regulated tariff to support the development and maintenance of competition.[126]

Following the draft determination, QCOSS' consultant (Etrog Consulting) concurred with the QCA's draft position that the AER's DMO process should not have implications for this price determination. Etrog said this is particularly the case since:

- the DMO is only applicable in non-price regulated jurisdictions, whereas the QCA is determining notified prices for a price-regulated jurisdiction for which the DMO is not relevant
- DMO prices are not set on the basis of a cost build-up (as notified prices are), and may be set at levels that do not reflect underlying costs.[127]

AER final determination

On 30 April 2019, the AER released its final determination of DMO prices for 2019–20. In its final determination, the AER:

- used a 'top-down' approach (as distinct from a 'bottom-up' analysis) for determining DMO prices[128]
- set DMO prices at the mid-point of the range between the median market offer and median standing offer (based on generally available offers in October 2018)[129]
- stressed that, in recommending establishment of the DMO, the ACCC was clear to differentiate the purpose of a DMO price from retail price regulation in areas where there is limited retail competition—the ACCC said that '[t]he default offer should not exist to be a price accessed by most, if not all, consumers in the market.'[130]
- noted that many stakeholders considered that a 'bottom-up' cost stack approach (similar to the QCA's methodology) would more accurately capture retailers' various costs, and there was broad support for moving to this approach in future years[131]
- said it did have regard to publicly available cost stack information, such as the QCA's estimate (for the draft determination) of efficient retail costs in south east Queensland[132]
- incorporated the QCA's wholesale energy cost forecasts (for the draft determination, based on ACIL Allen's advice) when assessing cost changes in the Energex distribution zone—and noted that, as the QCA's forecasts assess each tariff type separately, they provide a more granular and detailed assessment of expected changes in wholesale costs than the AEMC's price trends report[133]
- noted that it liaised with the QCA throughout the respective processes, and took account of relevant information from the QCA's process in making the DMO determination.[134]

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[126] Origin Energy, sub. 8, p. 1.
[127] QCOSS, sub. 35, attachment 1, p. 10.
[128] AER, April 2019, p. 7.
[129] AER, April 2019, pp. 10–11.
[130] AER, April 2019, p. 15.
[131] AER, April 2019, p. 23.
[132] AER, April 2019, p. 29.
[133] AER, April 2019, p. 51.
[134] AER, April 2019, p. 34.

QCA decision

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

- the AER has determined DMO prices for application in south east Queensland (not regional Queensland)
- the AER has determined 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 has determined the notified prices that will be paid by most customers in regional Queensland in a market where competition is limited.
- as indicated by stakeholders, the QCA's methodology and approach differ significantly from the AER's methodology[135] for determining DMO prices.

For these reasons, the QCA has not had regard to the AER's DMO process in this price determination. However, the QCA will monitor how development of the DMO progresses over time and may reconsider any potential implications in the determination of 2020–21 notified prices (if this task is delegated to the QCA).

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.

Considerations for this review

Key considerations for the QCA in determining the notified prices are discussed in Chapter 1, 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.[136] The delegation does not direct us to consider specific factors related to incorporating a headroom adjustment into notified prices.

6.3.1 Stakeholder comments

In the original submissions, some stakeholders supported the continued application of the headroom component in notified prices on the basis of the competition benefits:

[135] See AER, April 2019, for a full description of the AER's methodology for determining DMO prices.
[136] Section 90(5) of the Electricity Act.

- 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.[137]
- 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.[138]

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.[139]
- 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. [140]

In response to the QCA's draft determination position to incorporate a headroom adjustment of 5 per cent into notified prices for 2019–20:

- Cotton Australia reiterated its call for removal of the headroom component, specifically noting that:
  - there is no effective competition for most users in the Ergon distribution area
  - competition should be funded by innovation and efficiency, not by artificial inflation of the price.[141]
- QEUN said that as for the standing offer adjustment, the QCA should permanently remove the 'nonsensical' 5 per cent headroom charge.[142]
- Some other stakeholders also indicated that the headroom charge should be removed.[143]

6.3.2 QCA analysis and position

The QCA's final determination position is to incorporate a headroom adjustment of 5 per cent into notified prices in 2019–20. This approach:

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

[137] Origin Energy, sub. 8, p. 3.
[138] Energy Queensland, sub. 5, section 6.2.
[139] Cotton Australia, sub. 2, p. 3.
[140] Canegrowers Isis, sub. 3, p. 3.
[141] Cotton Australia, sub. 21, p. 5.
[142] QEUN, sub. 36, p. 3.
[143] P. Pollard, sub. 33, p. 1; E. Waters, sub. 43, p. 1.

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.

As before, barriers to the development of widespread competition include:

- 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.[144]

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.[145]

The QCA has considered the points raised in response to the draft determination by Cotton Australia, QEUN and other stakeholders suggesting the headroom charge should be removed, but does not consider that a persuasive case for changing the draft determination position on this matter has been made.

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.

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

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-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 has decided that SRES costs will be subject to a cost pass-through mechanism. While SRES costs are incurred by retailers, the level of costs is determined using the non-binding and final small-scale technology percentages (STPs) set by the Australian Clean Energy Regulator (CER), as discussed in detail in section 4.2.

This approach ensures notified prices:

- are updated to account for the final STP applicable in 2019, which was 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.

In the original submissions, stakeholders broadly supported this approach, provided any cost pass-throughs can be accurately identified.[146] 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.[147]

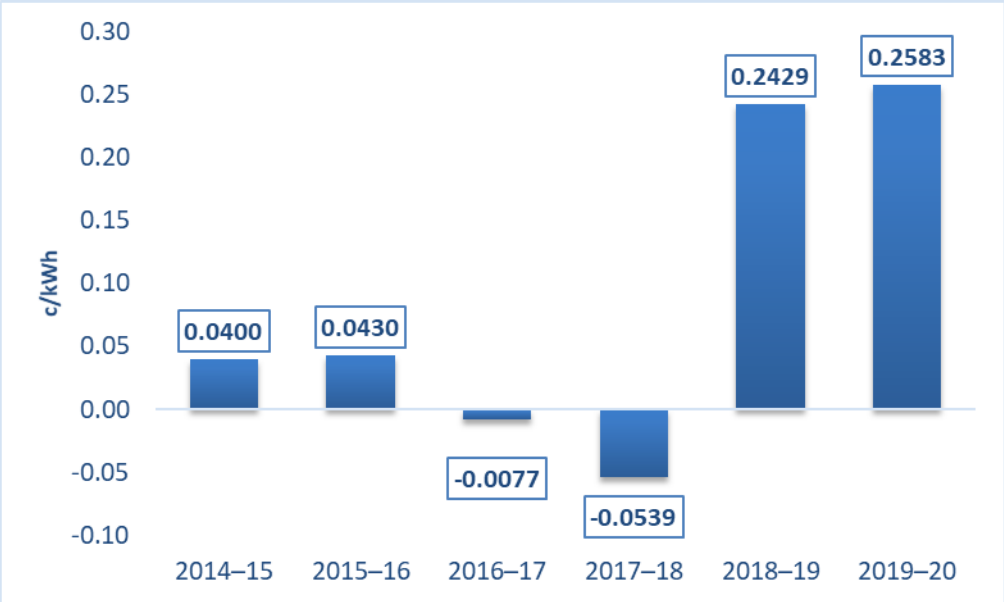
Origin Energy suggested that the QCA obtain updated estimates for inclusion in the draft determination, and consider revising (upward) the estimation provided by the CER's current non-binding STP for 2020.[148]

Based on the final STP for 2019 determined by the CER, retailers have under-recovered the costs of complying with the SRES in 2018–19. This is because the final STP for the second half of 2018–19 is 21.73 per cent, which is substantially higher than the non-binding STP of 12.13 per cent used for setting the SRES component of notified prices in 2018–19. As explained in section 4.2.1, the substantial difference between the two rates is largely due to a significant spike in the volume of STCs created—driven primarily by a higher than expected uptake of rooftop solar photovoltaic systems.

Accounting for these under-recovered SRES costs to retailers increases the usage charge by approximately 0.2583 c/kWh for residential tariffs and by 0.2619 c/kWh for small business tariffs. The comparatively large SRES cost pass-through relative to previous years (as seen in Figure 18) can be attributed to the considerable difference between the non-binding and final STP for 2019.

[146] Canegrowers Isis, sub. 3, p. 3; Origin Energy, sub. 8, p. 2; Energy Queensland, sub. 5, section 6.3.
[147] Origin Energy, sub. 8, p. 2.
[148] Origin Energy, sub. 8, p. 2.

Figure 18 SRES cost pass-through, residential customers



More detail on the SRES cost pass-through calculation is available in Appendix J. The table below presents our assessment of the 2018–19 under-recovered amounts.

Table 17 SRES under-recoveries in 2018–19

Settlement class	***Retail tariff***	***SRES under-recovery***
		c/kWh
Energex NSLP—residential and controlled loads	11, 12A, 14, 15, 31, 33	0.2583
Energex NSLP—small business and unmetered supply	20, 22A, 24, 41, 91	0.2619
Ergon Energy NSLP—small, medium, large (SAC) demand and streetlights	44, 45, 46, 50, 71	0.2437
Ergon Energy NSLP—high voltage—CAC & ICC	51A , 51B, 51C, 51D, 52A, 52B, 52C, 53	0.2323

Note: SRES under-recovery includes allowances for energy losses, variable retail costs, standing offer adjustment/ headroom and the time value of money.

QCA decision

Our final decision is to require a positive pass-through of an under-recovery of 2018–19 SRES costs into 2019–20 notified prices, as set out in the table above.

We consider this pass-through appropriate, given the QCA's intent for the pass-through mechanism has always been for it to operate symmetrically. Stakeholders generally supported this approach, which 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).

Depending on the regulatory framework that will apply to future price determinations and on whether any changes are made to the UTP or the subsidy arrangements underpinning it, the pass-through provisions discussed here may, or may not, remain appropriate in the future. Therefore, we cannot commit to the continued availability of a cost pass-through mechanism beyond this price determination.

The matters raised by Origin Energy are addressed 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:

- purchase of electricity from renewable or environmentally friendly sources[149]
- EasyPay Reward scheme, which entitles customers to rewards (payment credits) if they meet certain conditions (up until 30 June 2020).

We received minimal stakeholder feedback about the additional customer retail service activities (and charges). However, QEUN recommended that the EasyPay Reward scheme be modified to match conditions offered by the Alinta Energy / CS Energy joint venture in south east Queensland (a 28 per cent discount on usage/consumption charges if payment is received in full and on time).[150]

The QCA considers that the design and structure of these schemes, including the EasyPay Reward scheme, are government policy matters. Where stakeholders have additional 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.

Given this, there is no reason for the QCA to refuse to enable the additional services relating to renewable or environmentally friendly retailer services, or the EasyPay Reward scheme. The programs do not affect customers' rights to standard contract terms and conditions or notified prices.

The available schemes have been incorporated into the gazette notice (see Appendix F). 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

Prior to the draft determination, 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 18 shows the differences in timing between the two networks.

Table 18 Essential Energy controlled load intervals

Essential Energy tariff	*Current notified price retail tariff*

[149] Whether or not those additional amounts are calculated on the basis of the customer's electricity usage.
[150] QEUN, sub. 36, p. 10. The QCA notes that QEUN estimated the discount to represent an annual saving of $328. In the context of the earlier discussion of the standing offer adjustment, this could be viewed as further evidence to suggest a positive and significant value is associated with the terms and conditions of standard contracts.

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.

In the draft determination, the QCA proposed 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.

No stakeholders commented on this proposal in responses to the draft determination. As a consequence, the QCA has maintained the draft determination position in this final determination.

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 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 paragraph 5(d)(i) of the delegation.

The amended wording of the terms and conditions of the controlled load tariffs is contained in the 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 final 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

Background

In 2012, the government made a policy decision to move to electricity tariffs that support cost-reflective tariffs and encourage more efficient use of electricity. In general, tariff structures that provide correct signals when electricity costs more to supply (for example, during periods of peak network capacity) can encourage customers to make decisions that reduce the need for network capacity increases. While there are a number of factors feeding into network cost increases, one contributing factor was that the price signals being passed through in retail tariffs determined under the previous Benchmark Retail Cost Index price setting methodology did not send the correct price signals through to customers to inform them of the impact their usage decisions have on the network.

For example, under some previous retail tariffs, the price of electricity fell as the customer used more electricity. As a result, the retail tariff encouraged customers to use more electricity, place a greater strain on the network, and increase overall network costs. While not all tariffs had quite such perverse price signals, it was clear that a number of tariffs encouraged electricity use that would either result in higher costs, or result in customers receiving greater subsidies through the UTP, or both.

However, the decision to move towards more cost-reflective tariffs meant that most pre-existing tariffs did not reflect the levels, or structures, of underlying costs, and had to be either replaced or significantly changed. Changes in electricity tariff structures would benefit some customers, and others would see significant increases unless they altered their consumption patterns in response to the more cost-reflective price signals now being passed through.

Initially, the QCA recommended a 12-month period for customers to move from their existing tariffs to cost-reflective tariffs (commonly referred to as standard business tariffs), and alter their consumption patterns to match the new price signals they faced. Upon further analysis, it became clear that some customers had made investment and business decisions based on non-cost-reflective price structures and subsidy levels. The QCA subsequently decided to retain some of these non-cost-reflective tariffs for a transitional period to allow customers up to seven years to recoup some value from their existing investments and adjust their business practices to suit the tariff structures, and subsidy levels, of standard business tariffs.

The QCA was conscious of the fact that the decision to introduce a transition period would necessarily result in customers on these tariffs receiving an additional level of subsidy on top of that already prescribed by the UTP, and result in electricity usage that could increase overall electricity costs. On balance, the QCA considered that the small number of the worst affected customers should be given time to adjust their business practices to suit the standard business tariffs all other businesses must pay.

7.1.1 Existing transitional and obsolete tariffs

Some business customers, including farmers and irrigators, continue to be supplied under transitional or obsolete tariffs. As discussed above, these legacy retail tariffs do not reflect the underlying costs of supply and cannot be determined under an N+R approach.

In previous price determinations, the QCA decided that most of these existing transitional and obsolete tariffs[151] 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 decision

The QCA has maintained transitional arrangements for existing transitional and obsolete tariffs.

Data from Ergon Retail[152] 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.

7.1.2 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 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

In workshops and submissions, stakeholders expressed great concern regarding the expiry of transitional tariffs.

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

Irrigation groups supported extending transitional periods for transitional tariffs. Canegrowers, Canegrowers Isis and Kalamia Cane Growers Organisation[153] (Kalamia) supported extending transitional periods for tariffs 62, 65 and 66 beyond 2020. Mackay Canegrowers considered that all transitional tariffs should be extended until 2022, in line with tariffs 47 and 48. The Bundaberg Regional Irrigators Group (BRIG) supported transitional and obsolete tariffs remaining available for existing customers until 2025.[154] Cotton Australia supported allowing existing customers to remain on transitional tariffs indefinitely, or to ensure that existing customers on these tariffs could continue to access volumetric based tariffs so that they did not have to face demand charges.[155]

Many irrigation groups considered that there were no standard business tariffs that delivered a suitable price level or price structure for irrigators. Pioneer Valley Water submitted that customers should be allowed to stay on transitional tariffs indefinitely in the absence of what irrigators considered to be suitable alternative tariffs. Invicta Cane Growers Organisation stated that replacement irrigation tariffs were required to ensure a cost-effective transition.[156] Canegrowers Mackay stated that 'transitional tariffs should be maintained until a decision is made on an irrigation tariff or the price of existing business tariffs make it economically viable to transition'.[157]

Stakeholders also highlighted the impact of electricity price rises on their businesses and their international competitiveness. Canegrowers Mackay and Pioneer Valley Water stated that previous price increases had significantly impacted the profitability of their operations and feared any further increases from the move to standard business tariffs could render their businesses unviable. Pioneer Valley Water considered that it would take more time for businesses to adapt to standard business tariffs, due to the magnitude of price increases in recent years.

Stakeholders also highlighted the impacts of electricity price rises on customer behaviour. Mackay Canegrowers stated that electricity price increases had led to irrigators using less efficient irrigation practices, such as furrow irrigating, which lowered productivity and contributed to environmental problems. Invicta Cane Growers Organisation highlighted that a change in electricity tariffs may result in changes in customer behaviour, which may impact on grid stability.

Bundaberg Walkers stated that the move from energy-based tariffs to demand-based tariffs would have a significant impact on its business due to its highly peaky demand profile, with its demand being 15 times its base level consumption. While operational changes would reduce its forecast bill increase from 72 per cent to 15 per cent, the impacts of the operational changes would increase labour costs and potentially impact residential areas. Cotton Australia also highlighted the potential impact of demand tariffs on its members, and argued that if existing consumers were not allowed to remain on transitional tariffs indefinitely, they should be able to remain on volumetric-based tariffs instead of moving to demand-based tariffs.

[153] While Kalamia's comment was directed specifically at the Queensland Government, we consider its support for extending transitional periods to be a relevant factor for the QCA to consider when making our determination on these tariffs.
[154] BRIG, sub. 1, p. 4.
[155] Cotton Australia, sub. 21, p. 3.
[156] Invicta Cane Growers, sub. 26, pp. 1–2.
[157] Mackay Canegrowers, sub. 29, p. 3.

Stakeholders such as Invicta Cane Growers Organisation and Pioneer Valley Water highlighted that the increasing cost of electricity had many customers considering off-grid solutions, such as solar or diesel generation, and disconnecting from the grid. Cotton Australia and QFF also stated that the end of transitional arrangements would likely result in their members leaving the grid. Stakeholders stressed that customers leaving the grid would result in stranded assets, which may lead to higher costs for other users.

Stakeholders in Mackay, such as Pioneer Valley Water and the Kinchant Dam Water Users Association (Kinchant Dam), argued that their irrigation system was originally established with significant subsidies in place, and that the removal of these subsidies from the move towards cost-reflectivity in tariffs would make their irrigation system unviable. Stakeholders argued that moving to standard business tariffs would hinder regional development, and that while customers on these tariffs may receive a higher level of subsidy, this higher level of subsidy was warranted and should continue in the name of regional development.

Pioneer Valley Water considered the data provided by Ergon Retail to significantly understate the impact of moving to transitional tariffs as it fails to take practical considerations into account, and assumes the lowest cost tariff for comparison. QFF highlighted that, as some customers are supplied under multiple tariffs, the impacts may be greater than those presented in the data from Ergon Retail.

In its advice to Canegrowers, Sapere argued that there was no evidence that transitional tariffs did not cover the costs of supplying electricity under those tariffs, and claimed that 'the best available evidence strongly suggests the claim is false'.[158] This claim was based on a report written by Sapere, which claimed that 'irrigation demands in Queensland and elsewhere have a materially lower cost to supply compared with typical small business demand profiles of the same total volume of consumption'.[159] Sapere claimed that the wholesale energy cost for irrigators was lower than that of the NSLP. Sapere went on to claim that 'phasing out of legacy tariffs would be in breach of Section 90(5) of the Electricity Act 1994'.[160] Canegrowers Mackay considered that network congestion had been over-estimated, and pricing of tariffs should be reviewed.

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

QCA decision

The QCA has considered the views put forward by stakeholders, both in submissions and workshops. The QCA has maintained 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 that better reflect the costs of supply, which other regional businesses already face.

The QCA has considered Canegrowers' claim (and Sapere's supporting advice) that transitional tariffs 'more than cover the cost of delivering electricity to agricultural producers'.[161] Sapere considered that, based on interval data obtained from Energy Queensland, the volume weighted average wholesale electricity costs for irrigators are lower than the NSLP.[162] However,

[158] Canegrowers, sub. 18, attachment 1, p. 10.
[159] Canegrowers, sub. 18, attachment 1, p. 11.
[160] Canegrowers, sub. 18, attachment 1, p. 10.
[161] Canegrowers, sub.18, p. 1.
[162] Canegrowers, sub. 18, attachment 1, p. 11.

the cost to retailers of providing electricity for small business customers is based on the aggregated NSLP, regardless of an individual customer's load profile.

Sapere also contended that irrigator network costs are too high, due to the pricing structures employed by networks, or due to irrigators having to bear the costs of augmentation resulting from new connections.[163] However, the QCA must set prices based on the network tariffs levied by distributors.[164] Sapere's concerns regarding network prices should be directed to the AER as part of the AER's distribution pricing determination process.

The data provided by Ergon Retail clearly indicates that for some customers, including some irrigators, the electricity bills they currently pay are less than they would pay under standard business tariffs determined in accordance with the UTP—even where standard business tariffs are reflective of the lower costs in south east Queensland. This is confirmed by views expressed in multiple submissions from other customer groups, many of which state that moving to standard business tariffs would result in an increase in electricity bills. Some went as far as to say that the increase would be large enough to potentially affect the viability of their operations.

In addition, transitional tariffs do not reflect the tariff structures present in cost-reflective, or UTP-reflective, tariffs. These tariff structures determine customer pricing signals which are of vital importance in promoting efficient electricity supply and use. Bill impact data from Ergon Retail shows a range of bill impacts for customers on transitional tariffs, which highlights the mismatch between the cost-reflective, or UTP-reflective, price signals in standard business tariffs and those in transitional and obsolete tariffs.

The general economic principle of cost-reflective pricing leading to more efficient investment decisions and customer choices is well established. In examining farming and irrigation tariffs as part of its inquiry into electricity pricing, the Queensland Productivity Commission concluded:

> Notwithstanding farmers’ and irrigators’ concerns about impacts of tariff changes on electricity bills, prices should be set to reflect costs (taking into account the UTP). Otherwise, customers make inefficient choices about electricity use that can drive greater network investment.[165]

In response to the QPC's findings, the Queensland Government stated:

> The Government considers it is important that all customers move towards cost-reflective prices and considers that the current transition period (i.e. to 2020) is appropriate.[166]

The principle of cost reflectivity is also embedded in the network pricing objective in the National Electricity Law, which states:

> The network pricing objective is that the tariffs that a Distribution Network Service Provider charges in respect of its provision of direct control services to a retail customer should reflect the Distribution Network Service Provider's efficient costs of providing those services to the retail customer.[167]

In its recent electricity pricing inquiry, the ACCC recommended that 'steps should be taken to accelerate the take up of cost-reflective network pricing'.[168] The reasons for this were to reduce

[163] Canegrowers, sub. 18, attachment 1, pp. 14–15.
[164] Delegation terms of reference part 5. See Appendix A.
[165] Queensland Productivity Commission, *Electricity Pricing Inquiry Final Report,* 31 May 2016, p. 253.
[166] Queensland Government, *Queensland Government response to the Queensland Productivity Commission Electricity Pricing Inquiry,* November 2016, p. 11.
[167] Clause 6.18.5(a).
[168] Australian Competition and Consumer Commission, June 2018, recommendation 14, pp. 187.

costs and to 'more fairly distribute costs between customers'.[169] The ACCC also considered that demand tariffs were an appropriate pricing structure, balancing the objectives of 'cost reflectivity, simplicity and price certainty'.[170]

Ultimately, the QCA considers cost-reflective pricing, albeit after consideration of the UTP, best promotes the objective of the Electricity Act to promote efficient electricity supply and use. As such, the transition to standard business tariffs is necessary in order to promote the objective of the Electricity Act.

A number of stakeholders considered that even where customers receive additional subsidy due to transitional tariffs, the tariffs should be retained as a form of industry assistance and to help regional development. The question of whether a particular industry, or region, should be given taxpayer-funded assistance is beyond the scope of this report[171] and ultimately a policy decision for the Queensland Government.

However, the QCA does not consider transitional tariffs to be the most efficient way of providing industry, or regional, assistance, as they can lead to inefficient investment decisions by both customers and networks, and lead to higher overall costs of supplying electricity to customers.

The QCA does not support allowing existing customers to remain on transitional tariffs indefinitely, as suggested by Cotton Australia, even where it may be more cost-effective for these customers to leave the grid. In addition to the considerations above, 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.

Given 2019–20 is the final year of the transitional period for most transitional and obsolete tariffs[172], 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. We particularly encourage Ergon Retail customers to take advantage of their free service called Energy Analysis.[173] This service helps customers compare tariffs, understand what factors impact electricity bills, and recommends the best tariff based on recent electricity bills.

7.1.3 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.[174] 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.

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.

[169] Australian Competition and Consumer Commission, June 2018, p. 179.
[170] Australian Competition and Consumer Commission, June 2018, recommendation 14, p. 188.
[171] In 2015, the QCA conducted a separate investigation into industry assistance. This can be found on our website (http://www.qca.org.au/Productivity/Productivity-Projects/Industry-Assistance).
[172] Tariffs 47 and 48 will be available for existing customers until 30 June 2022.
[173] https://www.ergon.com.au/retail/business/account-options/energy-analysis-for-consolidated-accounts/register-for-energy-analysis or 1300 554 029.
[174] Tariff 37 cannot be accessed by new customers, as it was classified as obsolete on 1 July 2007.

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. Canegrowers stated they are working with the AER network tariff process, seeking tariffs specifically for food and fibre production. The QFF also argued for existing transitional and obsolete tariffs to be continued until the current AER process is finalised.

The QFF argued that access to transitional tariffs should remain unchanged, as tariff 66 is the 'drought tariff', and this decision would prevent drought-declared farmers from accessing the drought relief from electricity charges (DREC) scheme.

QCA decision

The QCA has reclassified transitional tariffs[175] 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 do not consider 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, 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.

According to the Queensland Government's website[176], the DREC scheme is not dependent on being supplied under tariff 66. It is available to any farmer who is drought declared, or within a drought-declared area, regardless of the electricity tariff they are on. As such, making transitional tariffs obsolete would not prevent drought-declared customers from accessing the scheme.

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

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

[176] https://www.business.qld.gov.au/industries/farms-fishing-forestry/agriculture/rural-disaster-recovery/drought/assistance/drecs—website viewed on 20 May 2019.

7.1.4 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[177] 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.[178] 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; 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

Irrigator groups highlighted the significant price increases that have occurred in the past, which have impacted both on-farm costs and water prices. Pioneer Valley Water submitted that the QCA should give serious consideration to the 'damage already being borne by regional economies as a result of current electricity prices'[179], highlighting the need for a reduction in transitional tariff prices. The QFF was disappointed that the QCA did not propose to pass on price savings in its draft determination, and said the decision would do nothing to help farmers.

QCA decision

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, when standard business tariffs also decreased.

7.2 Final determination on transitional arrangements

Table 19 outlines our final determination on transitional arrangements for 2019–20.

[177] 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.

[178] 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.

[179] Pioneer Valley Water, sub. 32, p. 2.

Table 19 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 FINAL DETERMINATION

This chapter sets out our final determination of regulated retail electricity prices (notified prices) to apply from 1 July 2019 to 30 June 2020, as well as 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 retail tariffs are discussed in Chapter 3.

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

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

The tariff schedule for 2019–20 is provided in Appendix F. The 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 regulated retail tariffs and prices for 2019–20. All tariffs in section 8.1 exclude goods and services tax (GST).

8.1 Notified prices

Table 20 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)	90.345		23.661		
Tariff 12A—residential (time-of-use)[b]	78.226	62.265	19.872		
Tariff 14—residential (time-of-use demand)[c]	45.773		15.835	59.412	8.532
Tariff 31—night rate (super economy)			17.913		
Tariff 33—controlled supply (economy)			19.268		

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 21 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	26.351	42.761	59.172	75.582	91.993	15.814	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—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 22 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)	124.936		24.432		
Tariff 22A—business (time-of-use)[b]	124.936	60.498	22.890		
Tariff 24—business (time-of-use demand)[c]	62.723		16.786	81.906	8.230
Tariff 41—low voltage (demand)	538.321		14.961		22.436
Tariff 91—unmetered			21.831		

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 23 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)	4627.229		12.540		36.288
Tariff 45—over 100 MWh medium (demand)	15302.159		12.540		27.028
Tariff 46—over 100 MWh large (demand)	40035.224		12.514		22.128
Tariff 50—over 100 MWh seasonal time-of-use (demand)[a]	3626.927	12.184	14.664	66.777	11.562
Tariff 71—street lighting[b]	0.525		28.465		

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 24 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)	25812.003		12.097	10.254	4.375	2.659	4.454
Tariff 51B—over 4 GWh high voltage (CAC 33kV)	18918.753		12.097	10.254	5.396	2.755	4.454
Tariff 51C—over 4 GWh high voltage (CAC 22/11kV Bus)	17434.053		12.101	10.254	6.259	3.339	4.454
Tariff 51D—over 4 GWh high voltage (CAC 22/11kV Line)	16585.653		12.120	10.254	12.355	6.736	4.454
Tariff 52A—over 4 GWh high voltage (CAC STOUD 33/66kV)a	13086.003	11.628	12.040	10.254	6.882	12.248	4.454
Tariff 52B—over 4 GWh high voltage (CAC STOUD 22/11kV Bus)[a]	13086.003	11.632	12.044	10.254	4.828	46.137	4.454
Tariff 52C—over 4 GWh high voltage (CAC STOUD 22/11kV Line)[a]	13086.003	11.651	12.063	10.254	8.937	80.540	4.454
Tariff 53—over 40 GWh high voltage (ICC)b	25622.108		12.097		4.375	2.659	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 25 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 26 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 What is the impact on customer bills?

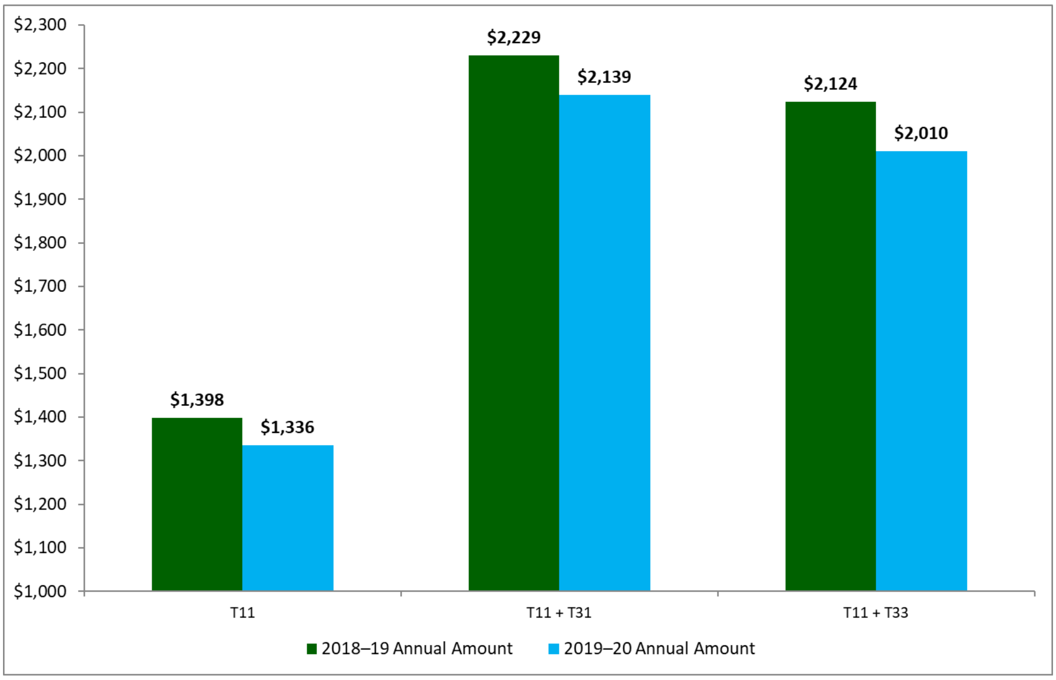
Residential customers

The typical residential customer on the main retail tariff (tariff 11) would pay around $62 (or 4.4 per cent) less per year for their electricity usage and service fee in 2019–20 (Figure 19).[180]

The typical residential customer on a combination of tariff 11 and controlled load[181] tariff 31 would pay around $90 (or 4 per cent) less per year, while the typical customer on a combination of tariff 11 and tariff 33 would pay around $114 (or 5.3 per cent) less per year.

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

Figure 19 Impact of notified prices on typical residential customers (incl. GST), 2019–20



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

[180] 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.

[181] 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).

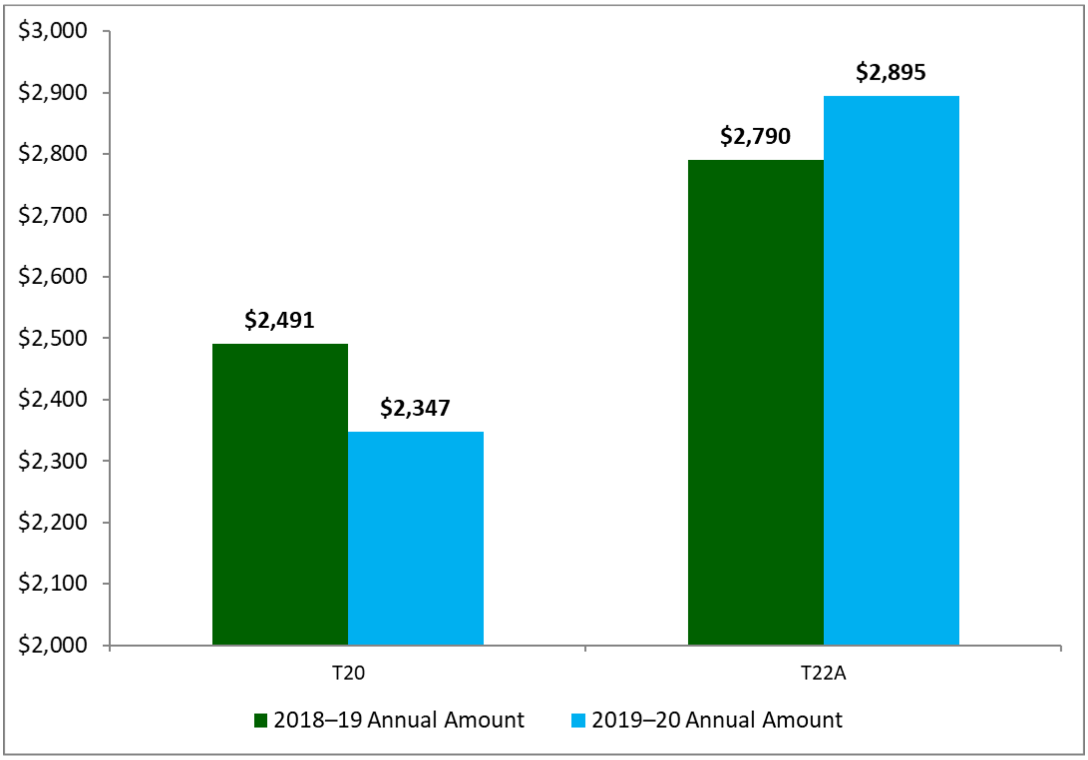
Small business customers

The typical small business customer on flat-rate tariff 20 would pay around $144 (or 5.8 per cent) less per year for their electricity usage and service fee in 2019–20.[182]

The typical small business customer on time-of-use tariff 22A would pay $105 (or 3.8 per cent) more per year for their electricity usage and service fee in 2019–20.[183]

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

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



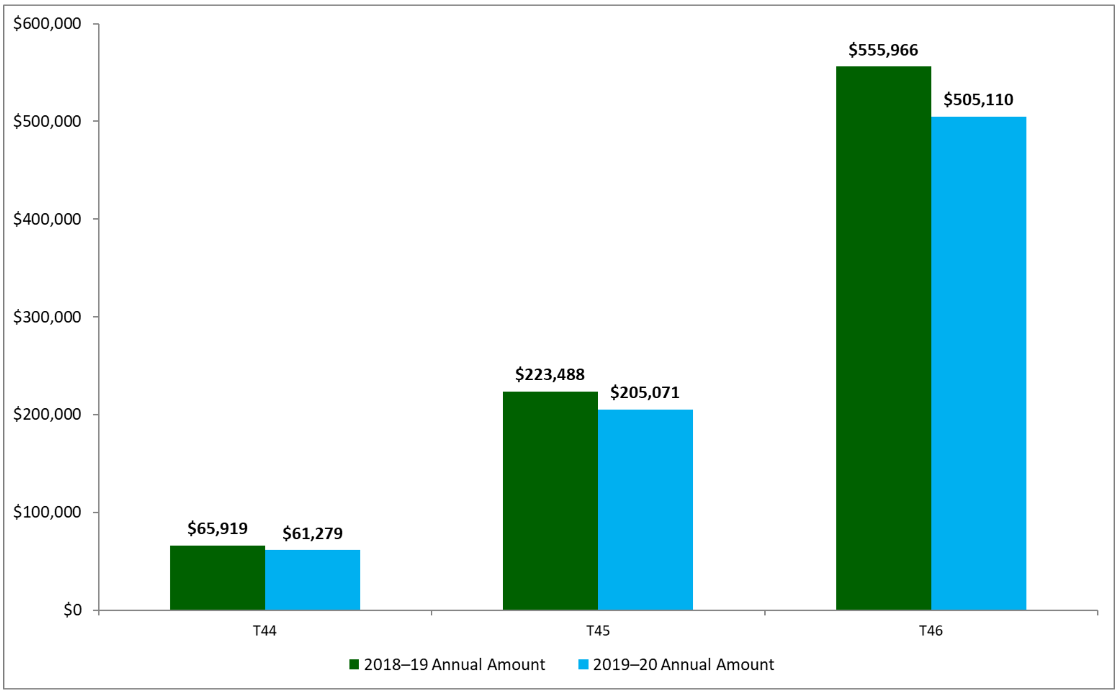
Note: Annual amounts are rounded to the closest dollar, and exclude metering charges.

Large business customers

A typical large business customer on tariff 44, 45 or 46 would pay between 7 per cent and 9.1 per cent less per year 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.

[182] 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.
[183] This increase is primarily driven by higher network charges for the peak period.

Figure 21 Impact of notified prices on typical large business customers (incl. GST), 2019–20



Note: Annual amounts are rounded to the closest dollar, and exclude metering charges. Changes in the annual bill calculations for typical customers since the draft determination are primarily due to the adjustment of consumption data for the typical customers, while retail prices have remained largely unchanged. Consumption data for typical customers have been adjusted since the draft determination, following further analysis of the data by QCA staff.

8.3 Obsolete tariffs

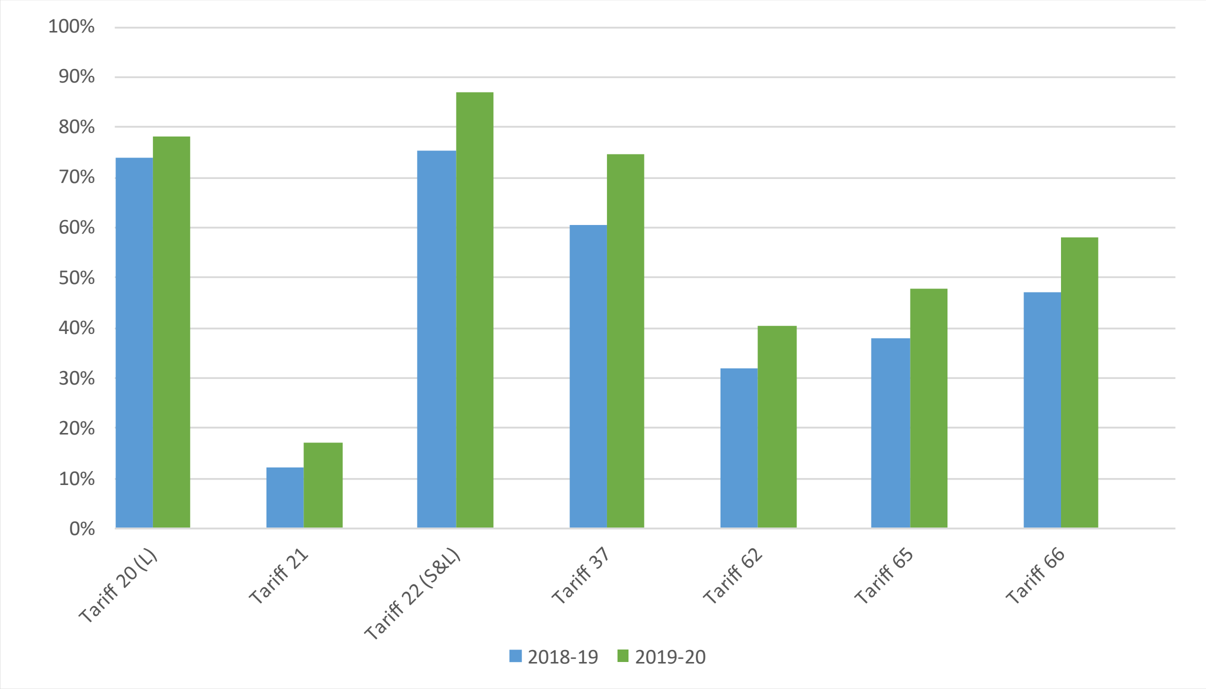
Around 35,000 connections, including some used by farmers and irrigators, are supplied under legacy retail tariffs. These tariffs were made available for several years to allow customers to transition their businesses to standard business tariffs. With the exception of tariffs 47 and 48[184], all of these tariffs will expire on 30 June 2020. In accordance with the delegation, the QCA has allowed existing customers to remain on these tariffs until they expire, but has closed 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 notified prices, around 40 per cent of all connections on expiring tariffs would save money on standard business tariffs in 2019–20. Figure 22 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.

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

Figure 22 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 23). 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 7 Approximate proportion of connections on tariffs 47 and 48 that could transition to standard business tariffs without any negative impact

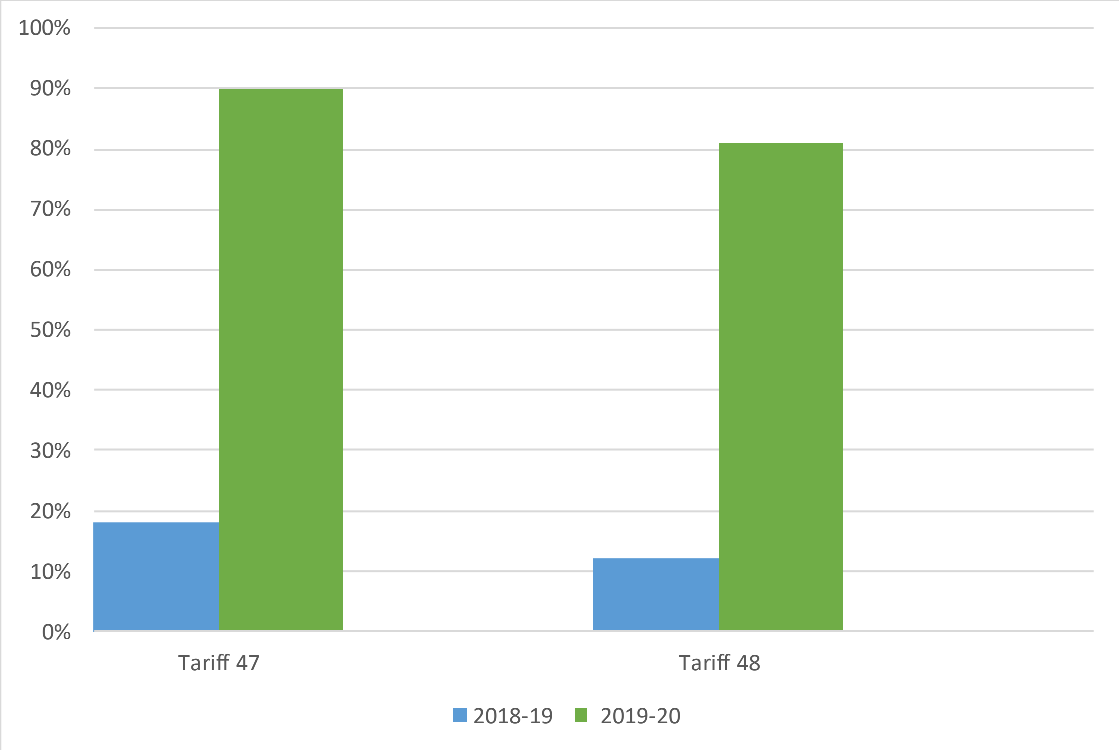


Table 27 Transitional arrangements for 2019–20

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

8.4 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.[185] Table 28 shows metering fees for large customers supplied via advanced digital meters.

Table 28 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.

[185] See Chapter 5 for further information.

GLOSSARY

ACCC	Australian Competition and Consumer Commission
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

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

Queensland Government

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

Interim consultation paper

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

Draft determination

Stakeholder	*Abbreviated form*	*Submission number*	*Date received*
Bohl, Adrian		13	12 April 2019
Brewer, Robyn		14	12 April 2019
Bunce, Lucia		15	12 April 2019
Bundaberg Walkers Engineering	Bundaberg Walkers	16	8 April 2019
Campion, Peter		17	12 April 2019
Canegrowers	Canegrowers	18	16 April 2019
Collyer, Denise		19	12 April 2019
Costigan, Erin		20	12 April 2019
Cotton Australia	Cotton Australia	21	15 April 2019
Duffield, Kent		22	12 April 2019
Energy Queensland	Energy Queensland	23	17 April 2019
Hinchinbrook Chamber of Commerce, Industry and Tourism	Hinchinbrook CCIT	24	12 April 2019
Ingham Building and Roofing		25	12 April 2019

Stakeholder	*Abbreviated form*	*Submission number*	*Date received*
Invicta Cane Growers Organisation	Invicta Cane Growers	26	12 April 2019
Kinchant Dam Water Users Association	Kinchant Dam	27	12 April 2019
Lord, Jill		28	12 April 2019
Mackay Canergrowers Limited	Mackay Canegrowers	29	12 April 2019
Mayo, John		30	12 April 2019
Meter2Cash	Meter2Cash	31	11 April 2019
Pioneer Valley Water Co-operative	Pioneer Valley Water	32	12 April 2019
Pollard, Phil		33	12 April 2019
Prescott, Beverley		34	12 April 2019
Queensland Council of Social Service	QCOSS	35	12 April 2019
Queensland Electricity Users Network	QEUN	36	15 April 2019
Queensland Farmers' Federation	QFF	37	12 April 2019
Ramke, Kevin		38	12 April 2019
Sheridan, Sandra		39	12 April 2019
Stubbins, Debra		40	12 April 2019
Tomlinson, Julian		41	12 April 2019
Toohey, Paula		42	12 April 2019
Waters, Elaine		43	12 April 2019
John White Crash Repairs		44	11 April 2019
Teece, Cate		45	1 May 2019
Confidential submission		–	16 April 2019

All non-confidential submissions are available on the QCA's website.

References

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

—*Estimated Energy Costs 2019–20 Retail Tariffs*, final report, prepared for the QCA, May 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, September 2013.

—*2018 Residential Electricity Price Trends Review*, final report, December 2018.

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

—*Understanding Load Profiles Published from MSATS*, August 2013.

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

Australian Energy Regulator (AER), *Default Market Offer Prices 2019–20*, final determination, April 2019.

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

Queensland Competition Authority, *Industry Assistance in Queensland*, final report, volumes 1 and 2, July 2015.

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.

Queensland Productivity Commission, *Electricity Pricing Inquiry,* final report, 31 May 2016.

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 so that it does not add to electricity bills.	BRIG QEUN	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 between 150 and 200 MW	Canegrowers Isis QEUN	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 QEUN	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 has set notified prices in accordance with the UTP as specified in the Queensland Government's delegation. This approach will 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.
The government should report on how the UTP is calculated and disclose the distribution of the community service obligation by customer category, region and industry sector.	QEUN	This matter is outside the scope of this report. Reporting on the UTP is a matter for the Queensland Government.
The EasyPay Reward scheme should be modified such that discounts are applied to each bill and that customers receive the same discounts and conditions as the Alinta Energy/CS Energy joint venture.	QEUN	This matter is outside the scope of this report. The EasyPay Reward scheme is a matter for the Queensland Government.
The non-reversion policy should be extended to customers consuming up to 160 MWh per year.	QEUN	This matter is outside the scope of this report. The non-reversion policy is a matter for the Queensland Government.
Introduce the Traffic Light System of demand response to lower power bills and maintain reliability standards.	QEUN	This matter is outside the scope of this report.
Maintain network reliability standards at current levels without increasing power bills	QEUN	This matter is outside the scope of this report. Further information on the reliability standards review is on our website at http://www.qca.org.au/Electricity/Regional-consumers/ministerial-advice/In-Progress/Distribution-Network-Reliability-Standards-for-202.

Stakeholder comment	***Stakeholder***	***QCA response***
Replace the current delegation to the Queensland Competition Authority with a ministerial delegation to either the Queensland Competition Authority or the Queensland Productivity Commission to investigate and report on matters relating to the affordability and reliability of electricity in regional Queensland.	QEUN	This matter is outside the scope of this report. The delegation is a matter for the Queensland Government.
Public acknowledgement that under the Constitution it is the responsibility of the Queensland Government, not the Queensland Competition Authority, to set regulated retail electricity prices in regional Queensland.	QEUN	This matter is outside the scope of this report. The responsibility for setting notified prices is set out in legislation (the Electricity Act). In accordance with the Electricity Act, the Minister has delegated relevant functions to the QCA for 2019–20. Whether any further public statement is necessary is a question for the Queensland Government.

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 29 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 30 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[186], 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[187] 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 31 and 32.

Table 31 Network price options for tariff 12A

	Fixed c/day	***Peak/flat c/kWh***	***Off-peak c/kWh***
Energex 8400	48.800	8.424	–
Ergon Distribution ERTOUT1	135.000	41.467	5.182
QCA-adjusted Ergon Distribution ERTOUT1	37.258	41.467	5.182

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 32 Network price options for tariff 22A

	Fixed c/day	***Peak/flat c/kWh***	***Off-peak c/kWh***
Energex 8500	66.200	8.801	–
Ergon Distribution EBTOUT1	135.000	46.813	8.944
QCA-adjusted Ergon Distribution EBTOUT1	66.200	39.252	7.499

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.

[186] Energex and Ergon Distribution.
[187] 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 33 and 34.

Table 33 Network price options for tariff 14

	Fixed c/day	*Usage c/kWh*	*Peak demand $/kW/month*	*Off-peak demand $/kW/month*
Energex 8400	48.800	8.424	–	–
Ergon Distribution ERTOUDCT1	10.000	2.719	80.078	11.500
QCA-adjusted Ergon Distribution ERTOUDCT1	6.350	1.726	50.852	7.303

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 34 Network price options for tariff 24

	Fixed c/day	*Usage c/kWh*	*Peak demand $/kW/month*	*Off-peak demand $/kW/month*
Energex 8500	66.200	8.801	–	–
Ergon Distribution EBTOUDCT1	10.000	3.375	99.515	10.000
QCA-adjusted Ergon Distribution EBTOUDCT1	6.949	2.345	69.154	6.949

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 35 and 36). Network prices calculated using this approach are consistent with the UTP.

The impact on customers are shown in Figures 24 and 25.

Table 35 Network price options for tariff 11

	Fixed c/day	*Usage c/kWh*		
		Flat/first block [a]	*Second block* [b]	*Third block* [c]
Energex 8400	48.800	8.424	–	–
Ergon Distribution ERIBT1	135.000	3.218	6.318	10.093
QCA-adjusted Ergon Distribution ERIBT1[d]	97.804	2.331	4.577	7.312

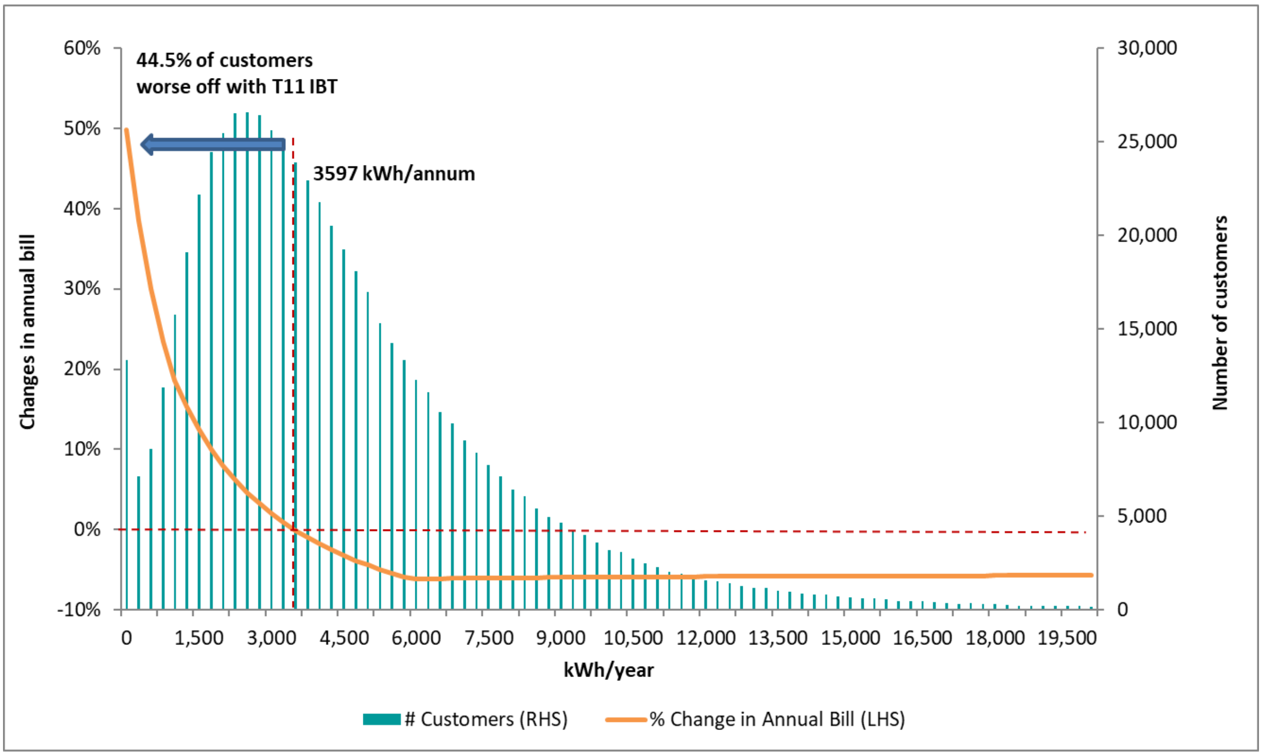
a *Usage charge applies to all usage under an Energex network tariff (row 1). Usage charge applies to the average usage of less than 2.74 kWh per day under an Ergon Distribution network tariff (rows 2 and 3).*

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 24 Impact on tariff 11 customers adopting the 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 3597 kWh/annum) on average will be worse off moving from a residential flat tariff (tariff 11) to Ergon Distribution inclining block tariff structure.*

Table 36 Network price options for tariff 20

	Fixed c/day	Usage c/kWh		
		Flat/first block [a]	*Second block* [b]	*Third block* [c]
Energex 8500	66.200	8.801	–	–
Ergon Distribution EBIBT1	135.000	3.574	8.944	12.988
QCA-adjusted Ergon Distribution EBIBT1[d]	104.261	2.760	6.907	10.030

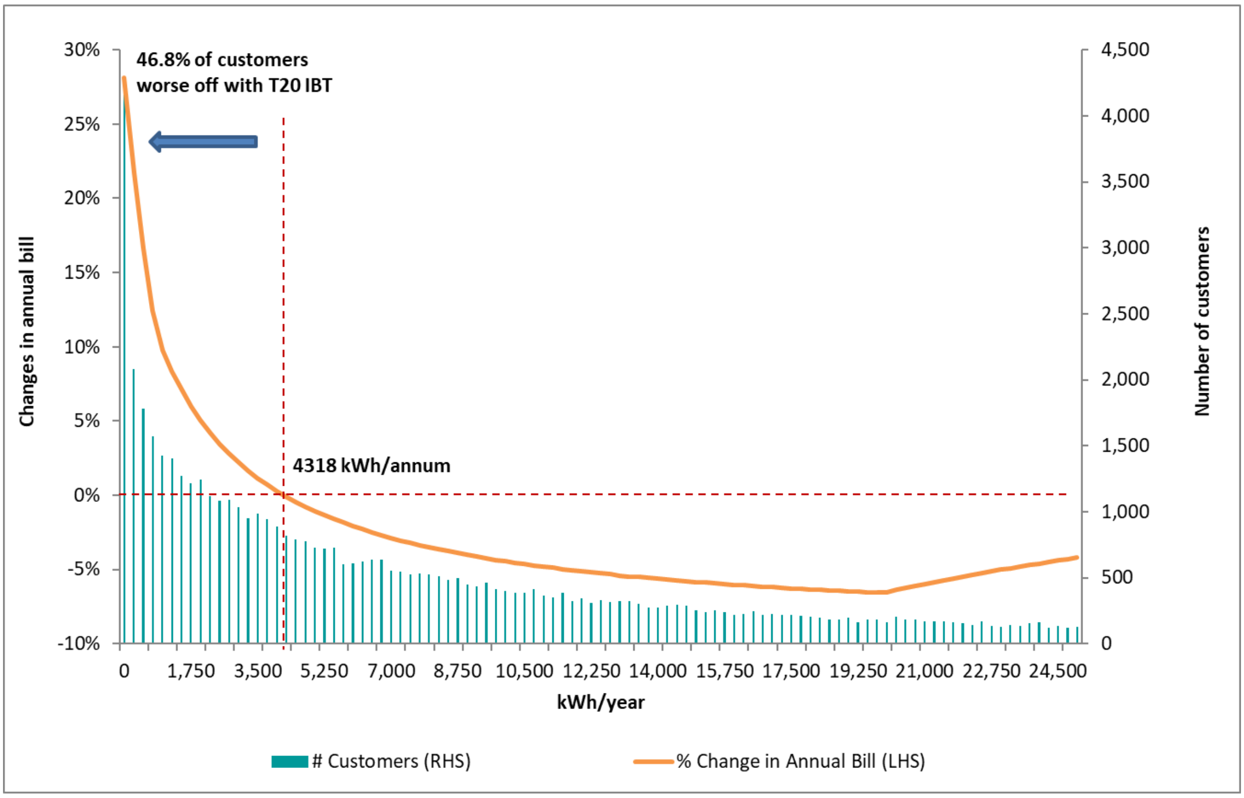
a *Usage charge applies to all usage under an Energex network tariff (row 1). Usage charge applies to the average usage of less than 2.74 kWh per day under an Ergon Distribution network tariff (rows 2 and 3).*

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 25 Impact on tariff 20 customers adopting the Ergon Distribution inclining block tariff structure



a *IBT—inclining block tariffs.*

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

c *46.8% of customers (consuming below 4318 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 final 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.

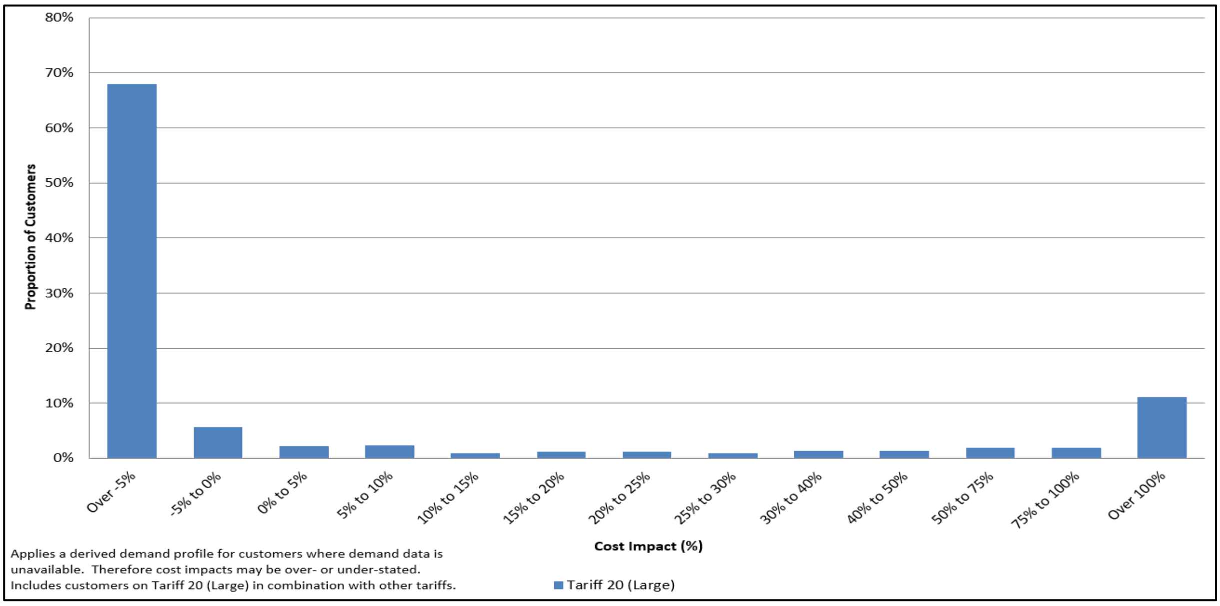
This appendix contains the analysis of bill impacts for customers moving from a 2018–19 transitional or obsolete tariff to an alternative 2018–19 standard business tariff.

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 26 shows the likely impacts for large business customers moving from this transitional tariff to the most appropriate standard large business customer tariffs.

Figure 26 Change in electricity bills for business customers on tariff 20 (large) moving to large customer standard business tariffs

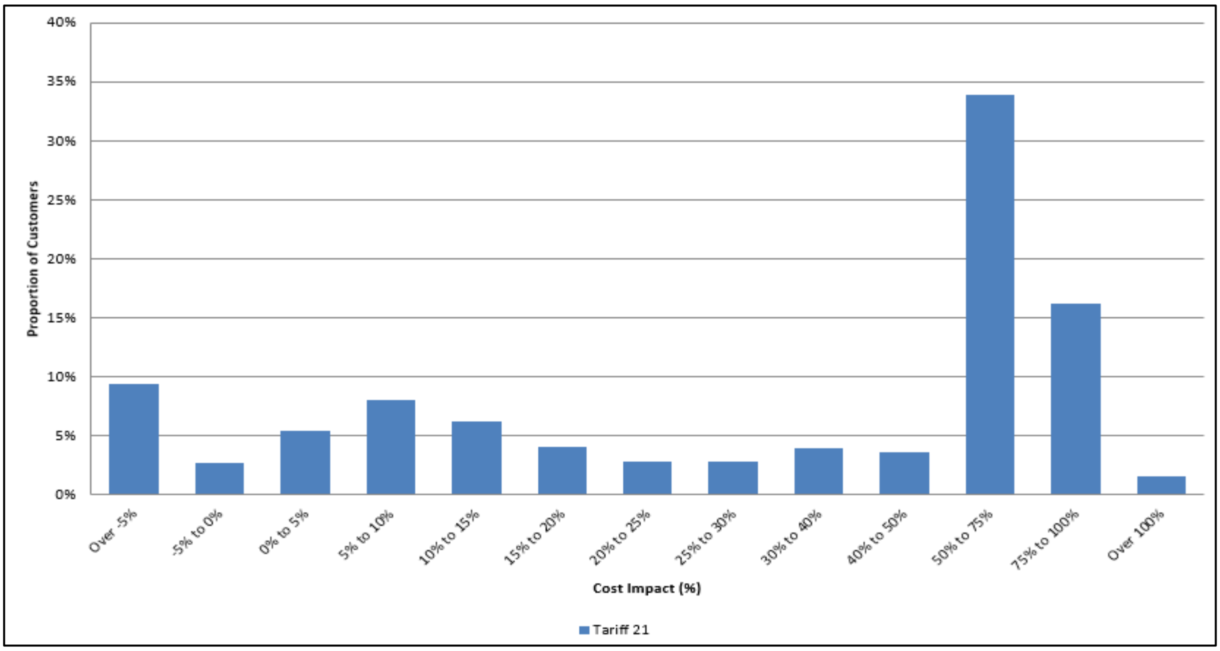


Source: Ergon Retail.

Tariff 21

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

Figure 27 Change in electricity bills for small business customers on tariff 21 moving to tariff 20

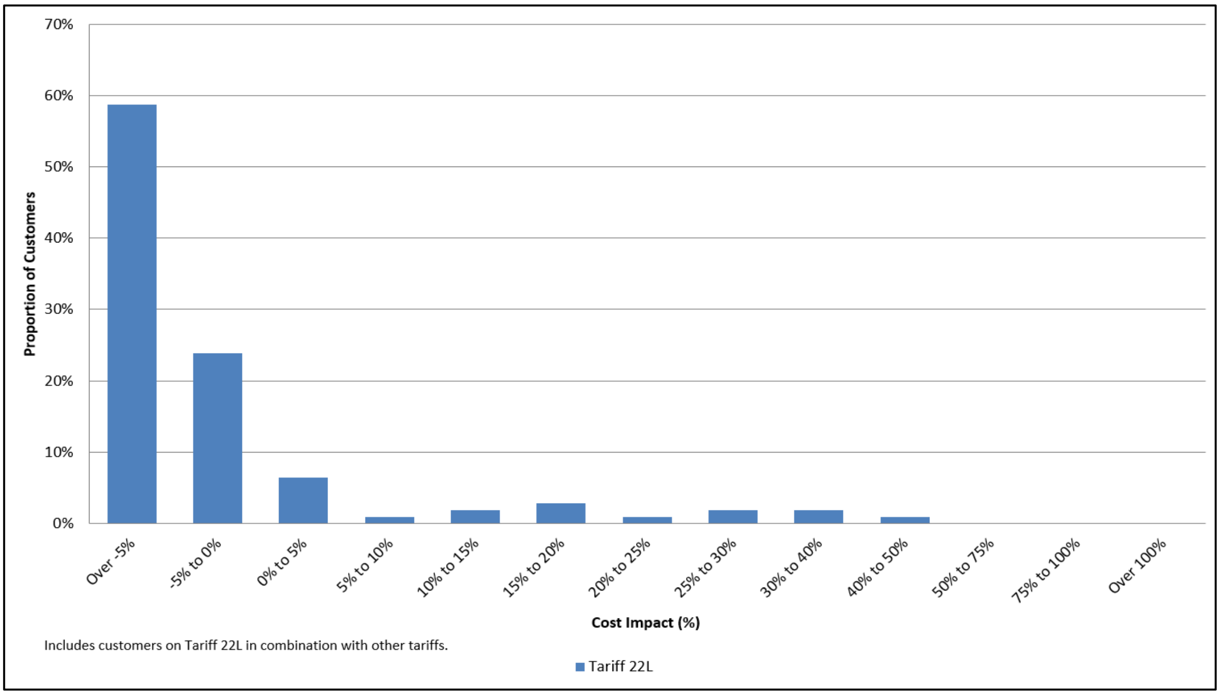


Source: Ergon Retail.

Tariff 22 (small and large)

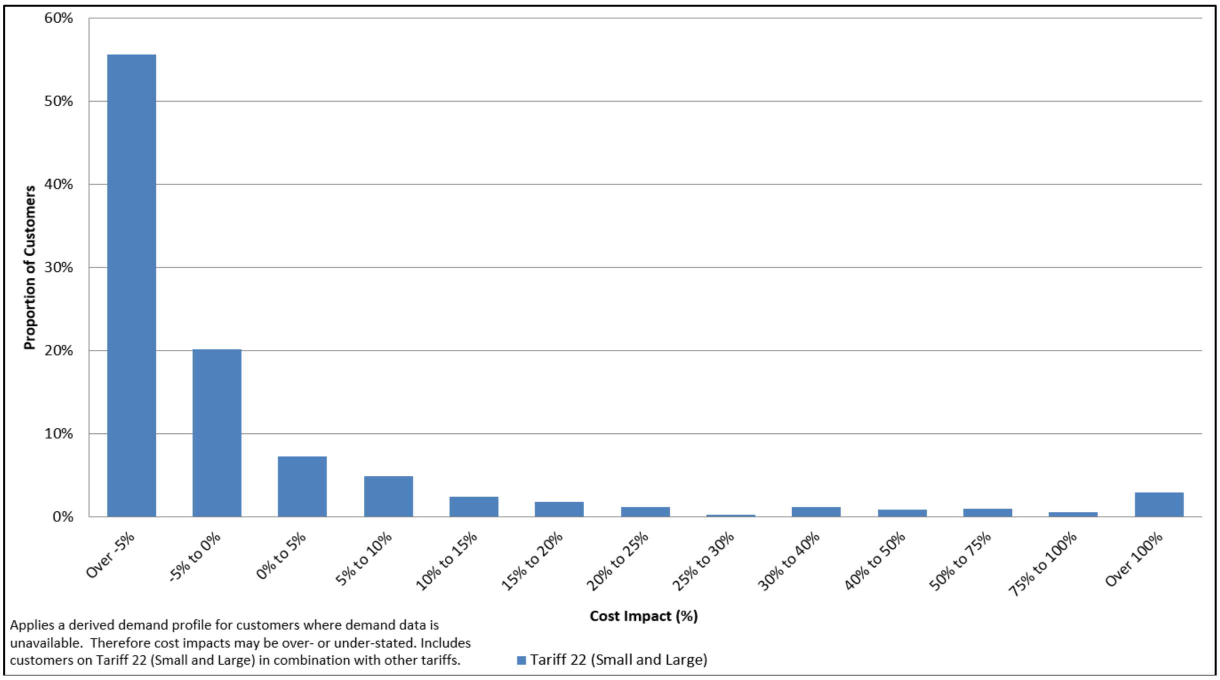
Transitional tariff 22 (small and large) aligns with tariff 20 for small business customers and tariffs 44 to 53 for large business customers, which are based on Ergon Energy network tariffs and charges. Figures 28 to 29 show the likely impacts for business customers moving from these transitional tariffs to the most appropriate standard business customer tariffs.

Figure 28 Change in electricity bills for large business customers on tariff 22 (small and large) moving to small customer standard tariffs



Source: Ergon Retail.

Figure 29 Change in electricity bills for large business customers on tariff 22 (small and large) moving to large customer standard tariffs

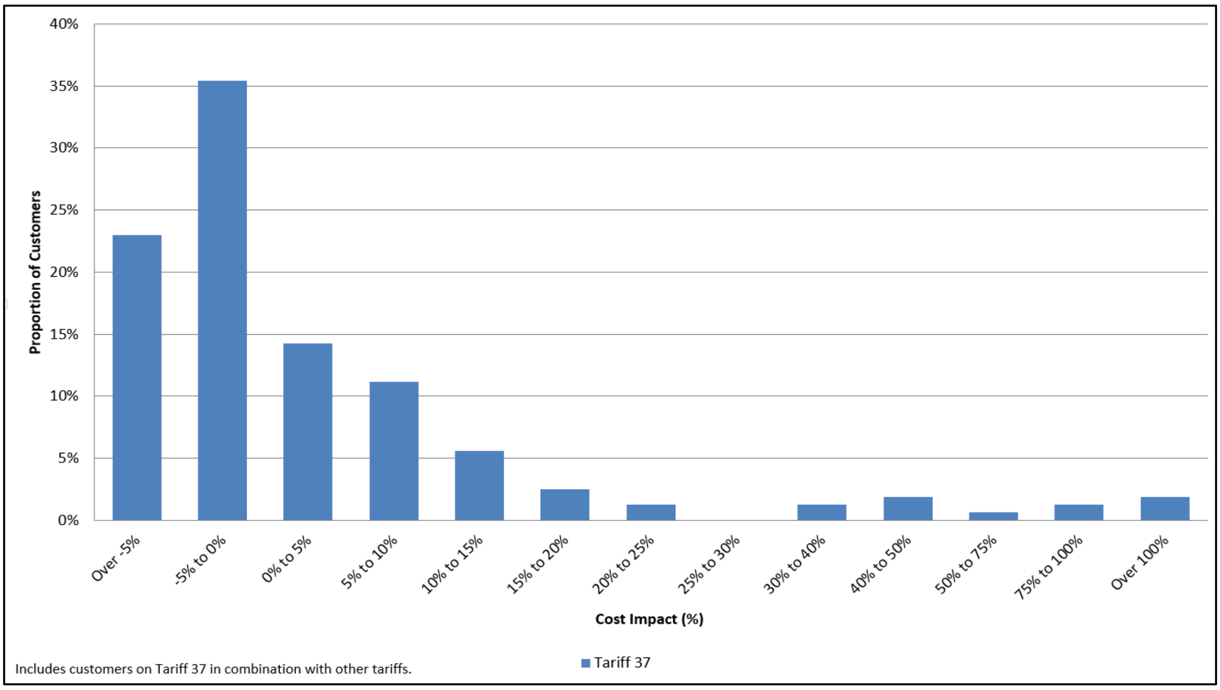


Source: Ergon Retail.

Tariff 37

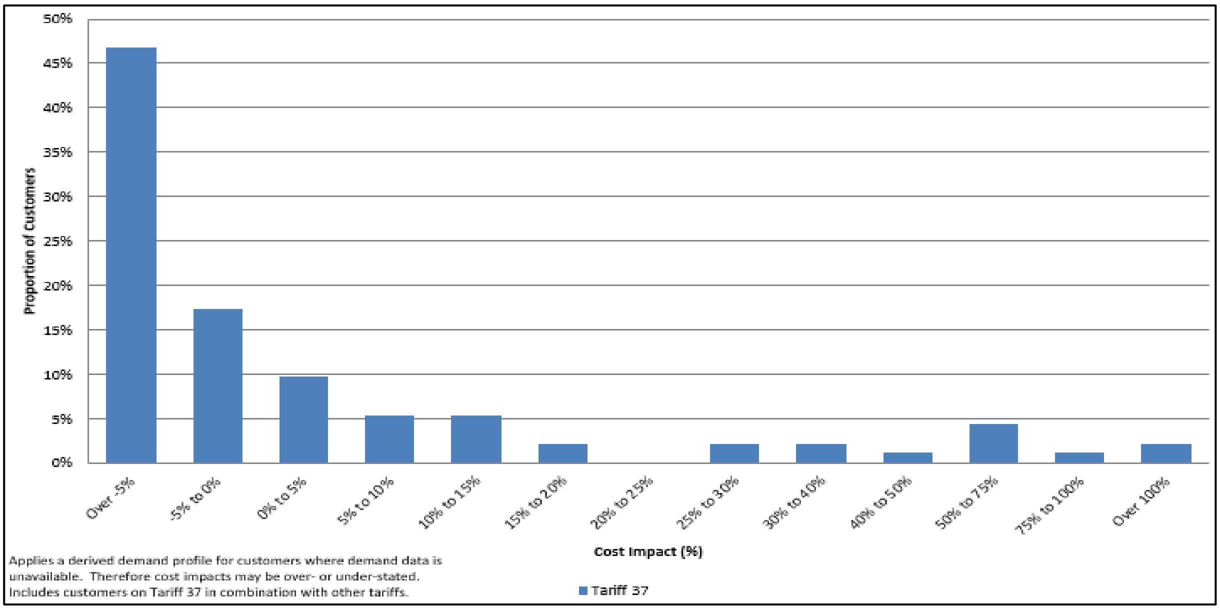
Tariff 37 is a business time-of-use tariff that aligns with tariffs 20 or 22A for small business customers and one of tariffs 44 to 53 for large business customers. Figures 30 and 31 show the distribution of potential impacts for existing customers moving to these standard business tariffs.

Figure 30 Change in electricity bills for small business customers on tariff 37 moving to tariff 20



Source: Ergon Retail.

Figure 31 Change in electricity bills for large business customers on tariff 37 moving to large customer standard business tariffs

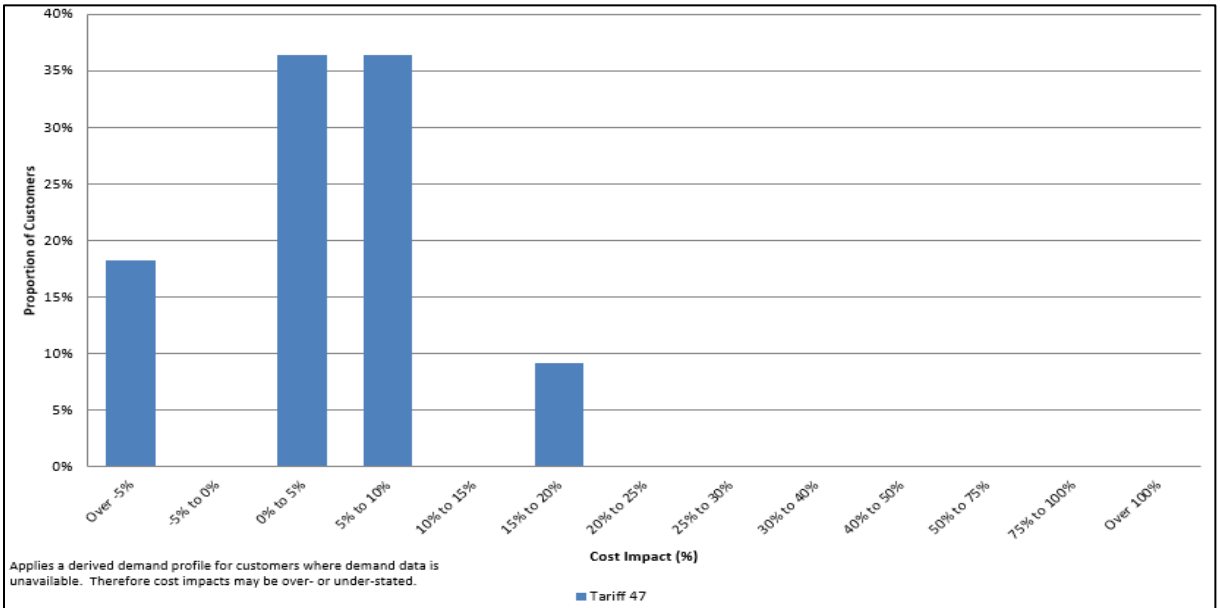


Source: Ergon Retail.

Tariffs 47 and 48

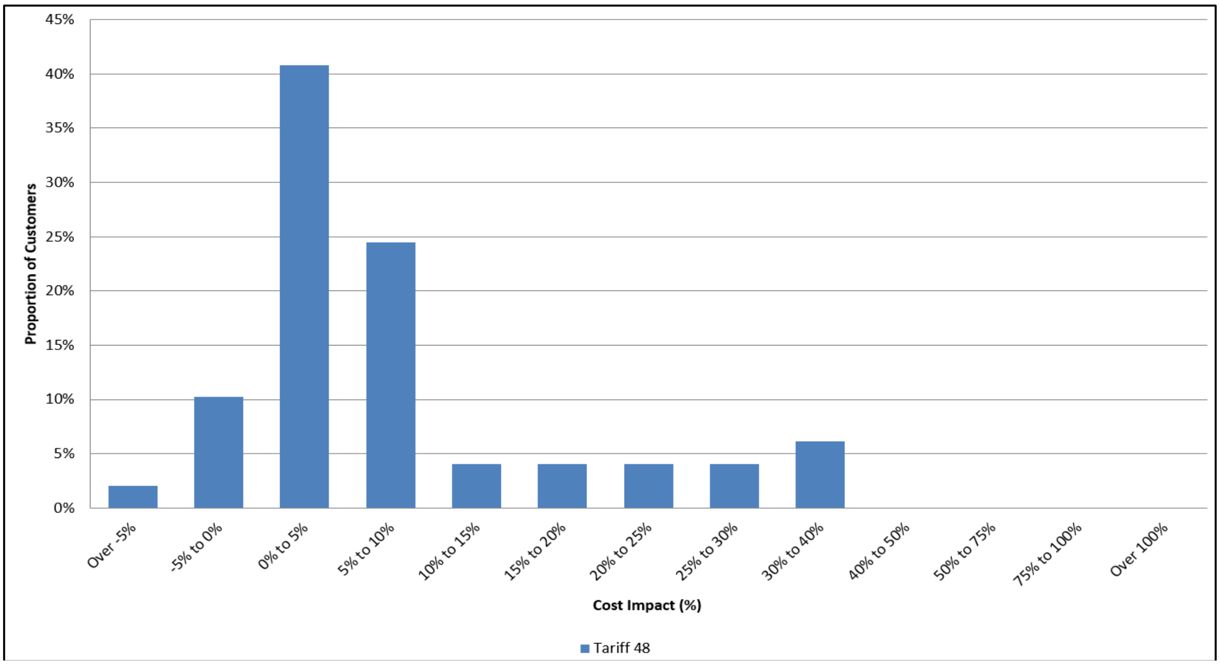
Transitional tariffs 47 and 48 (both very large) align with tariffs 51A–D, 52A–C and 53, which are based on Ergon Energy network tariffs and charges. Figures 32 and 33 show the likely impacts for large business customers moving from transitional tariffs 47 and 48 to the most appropriate standard business tariffs.

Figure 32 Estimated bill impact for customers moving from tariff 47 to standard business tariffs



Source: Ergon Retail.

Figure 33 Estimated bill impact for customers moving from tariff 48 to standard business tariffs

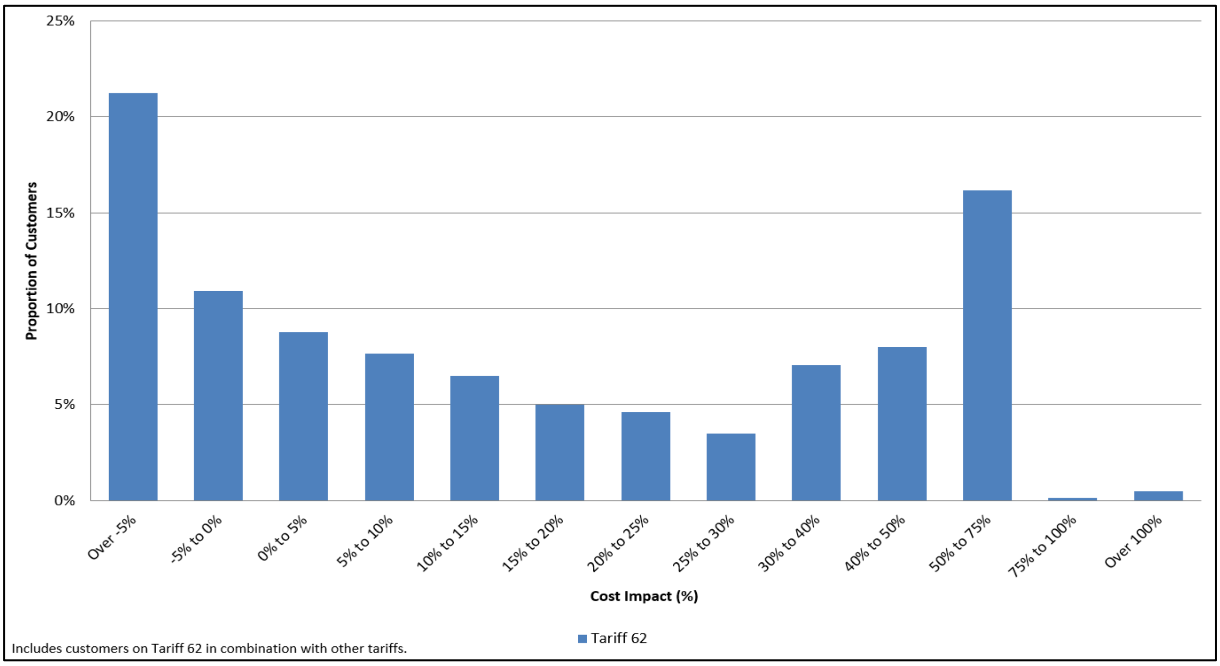


Source: Ergon Retail.

Tariffs 62 and 65

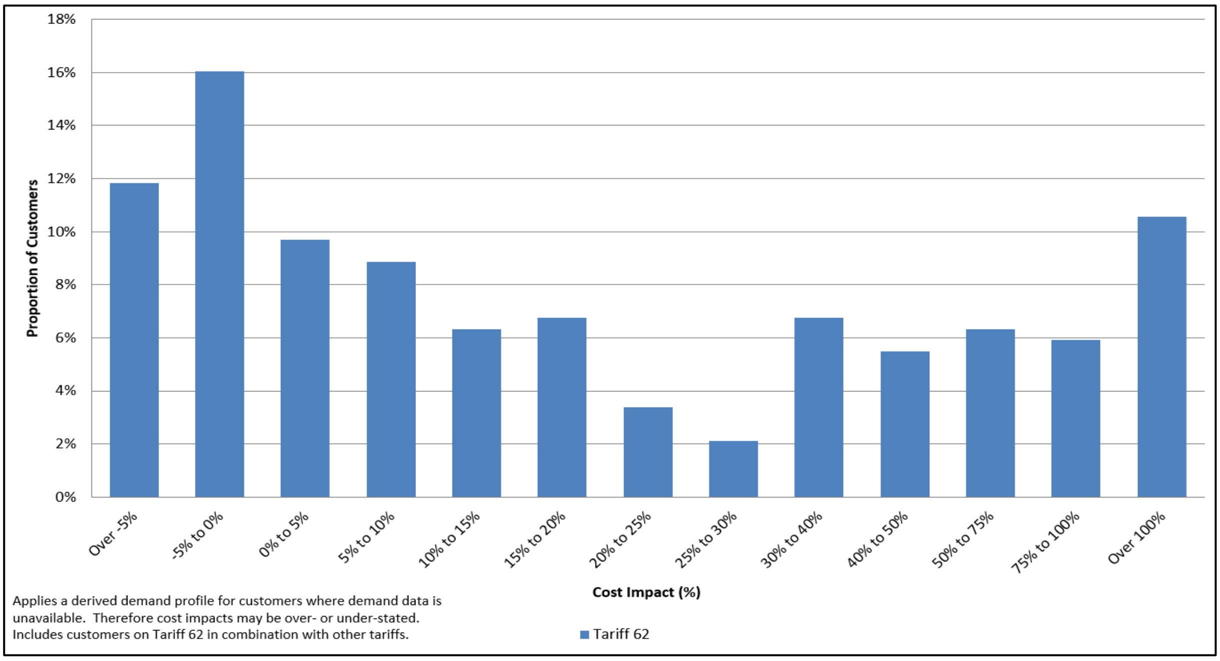
Tariffs 62 and 65 are time-of-use tariffs for farming and irrigation customers. These tariffs align with tariffs 20 or 22A for small business customers and tariffs 44 and 45 for large business customers. Figures 34 to 37 show the distribution of potential impacts for existing customers moving to these standard business tariffs.

Figure 34 Change in electricity bills for small business customers on tariff 62 moving to tariff 20



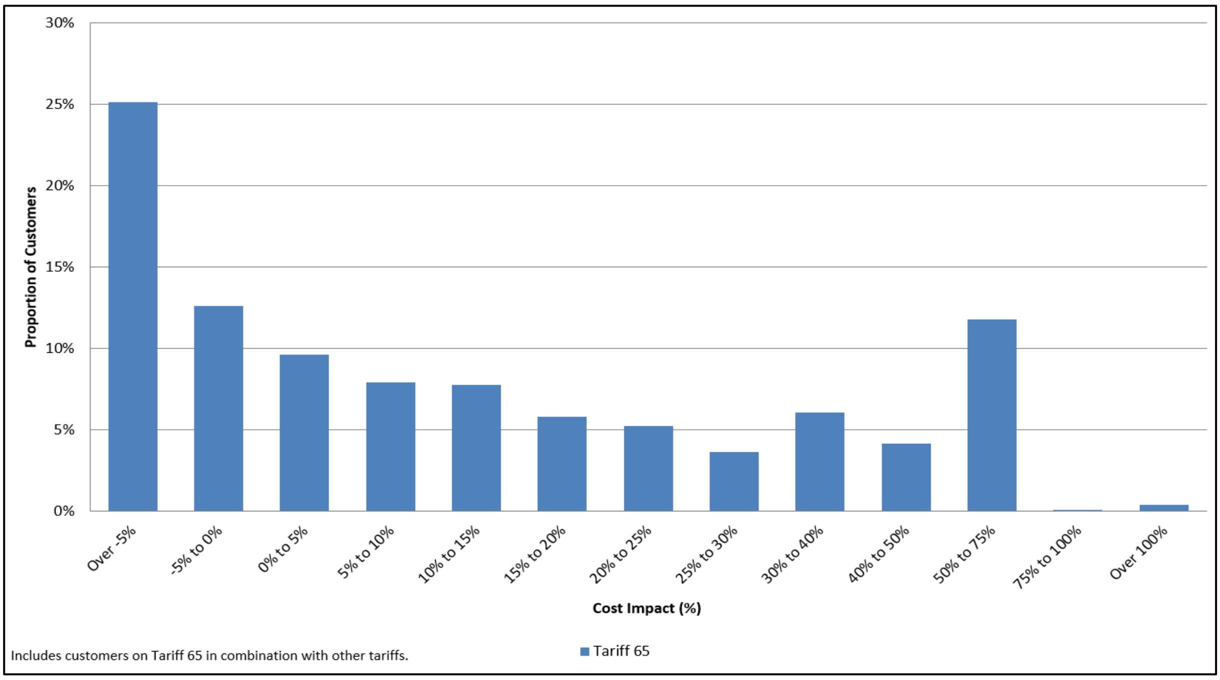
Source: Ergon Retail.

Figure 35 Change in electricity bills for large business customers on tariff 62 moving to large customer standard business tariffs



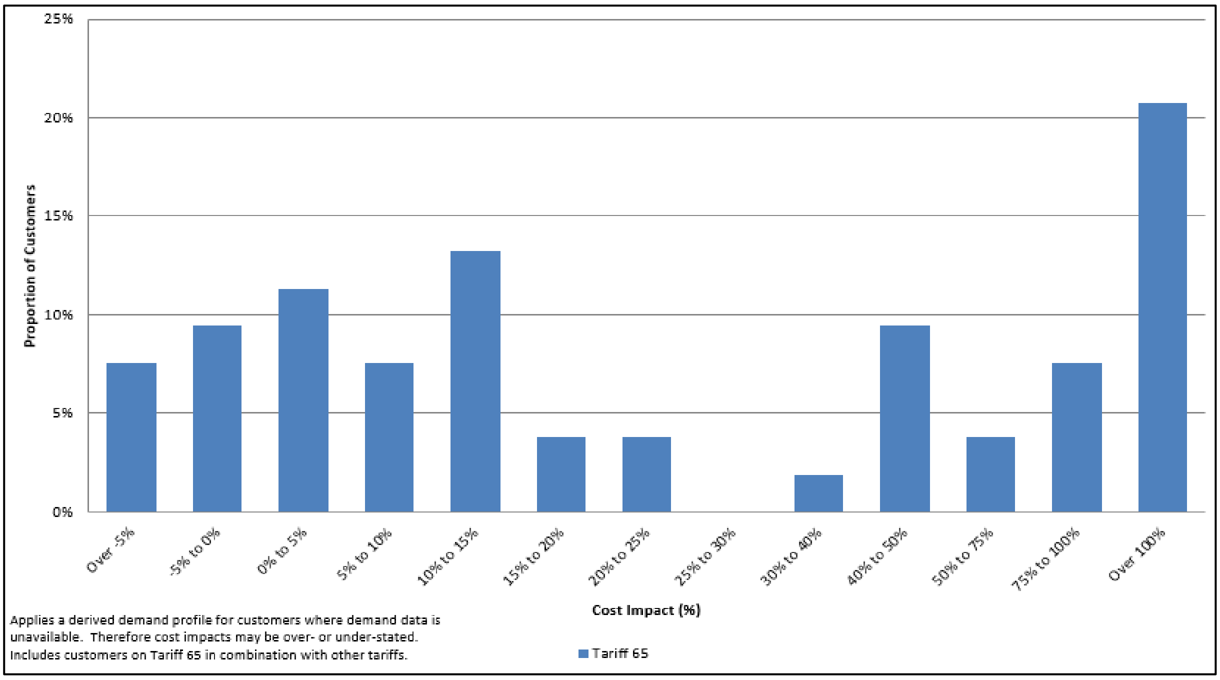
Source: Ergon Retail.

Figure 36 Change in electricity bills for small business customers on tariff 65 moving to tariff 20



Source: Ergon Retail.

Figure 37 Change in electricity bills for large business customers on tariff 65 moving to large customer standard business tariffs

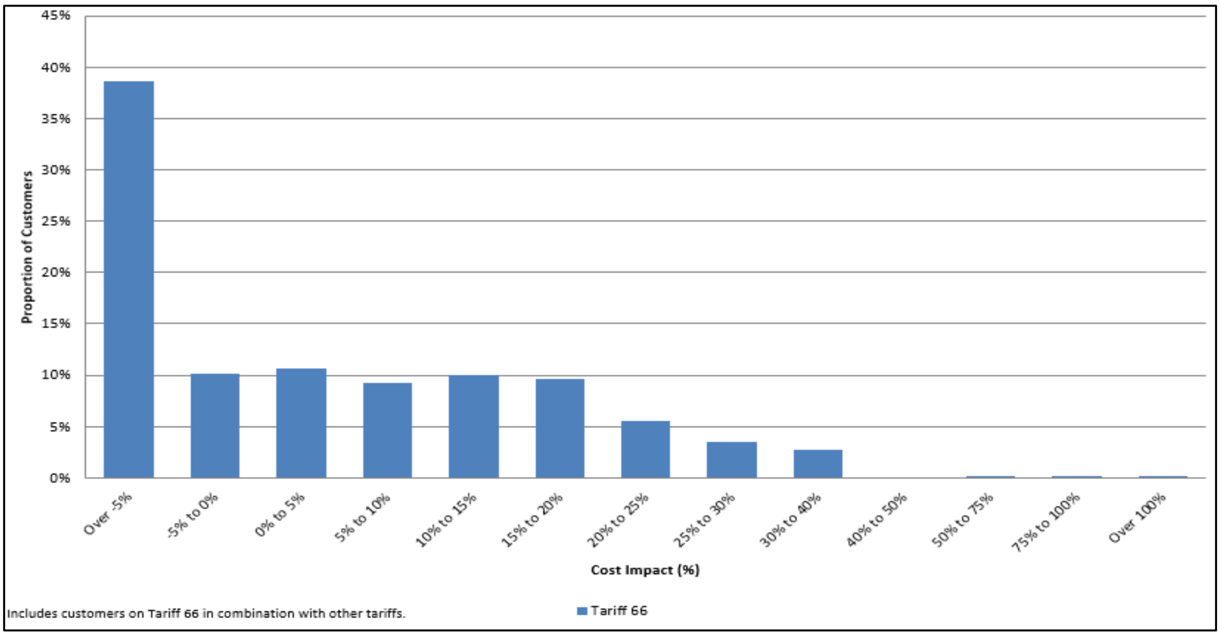


Source: Ergon Retail.

Tariff 66

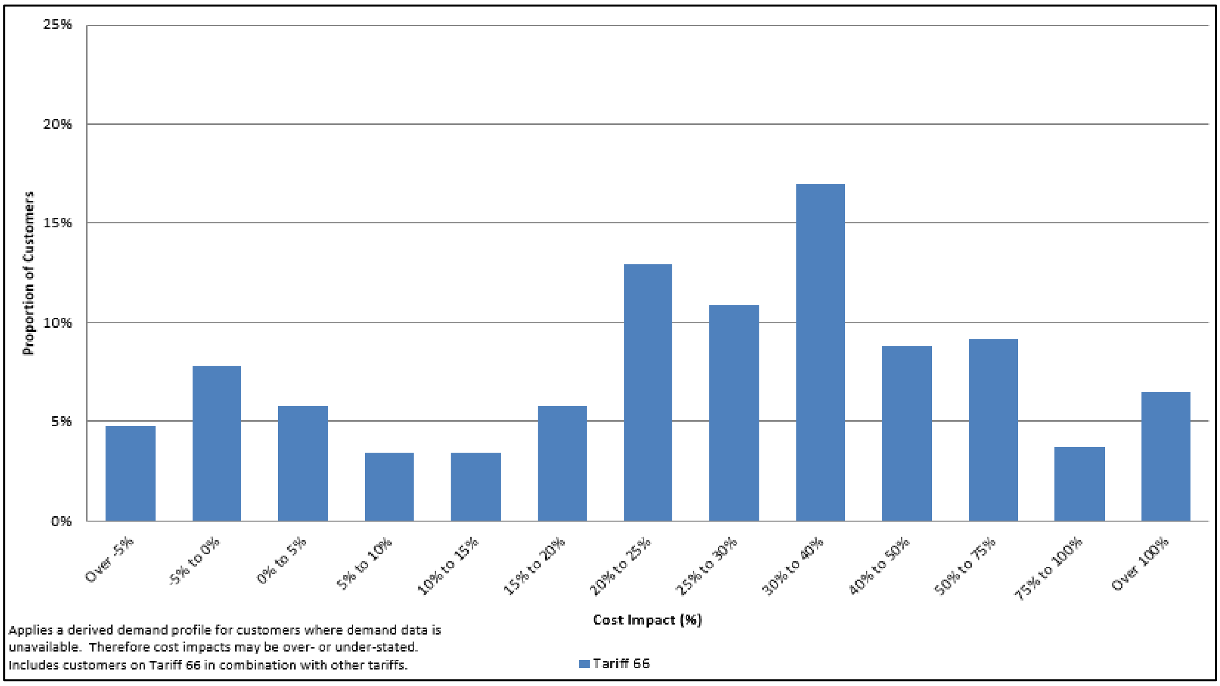
Tariff 66 is a flat-rate tariff for irrigation customers. This tariff aligns with tariffs 20 or 22A for small business customers and tariffs 44 and 45 for large business customers. Figures 38 and 39 show the distribution of potential impacts for existing customers moving to these standard business tariffs.

Figure 38 Change in electricity bills for small business customers on tariff 66 moving to tariff 20



Source: Ergon Retail.

Figure 39 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 gazette notice for 2019–20, which reflects the QCA's final 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 31st 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 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 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	23.661	c/kWh
		Daily supply charge	90.345	c
12A	Residential seasonal time-of-use primary tariff	Summer usage – Peak (3pm–9:30pm)	62.265	c/kWh
		Summer usage – All other times	19.872	c/kWh
		Usage – All other times	19.872	c/kWh
		Daily supply charge	78.226	c
14	Residential seasonal time-of-use monthly demand primary tariff.	Chargeable demand – Peak	59.412	$/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	8.532	$/kW
		Usage	15.835	c/kWh
	Peak chargeable demand is the average of the four highest peak daily demands in the month.	Daily supply charge	45.773	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	15.814	c/kWh
	-Band 1 has a 0 kWh cap during the summer peak window	Fixed charge - band 1	26.351	$/month
	-Band 2 has a 5 kWh cap during the summer peak window	Fixed charge - band 2	42.761	$/month
	-Band 3 has a 10 kWh cap during the summer peak window	Fixed charge - band 3	59.172	$/month
	-Band 4 has a 15 kWh cap during the summer peak window	Fixed charge - band 4	75.582	$/month
	-Band 5 has a 20 kWh cap during the summer peak window	Fixed charge - band 5	91.993	$/month
20	Small business flat-rate primary tariff.	Usage	24.432	c/kWh
		Daily supply charge	124.936	c

Tariff	Description	Charge type	Rate	Unit
22A	Small business seasonal time-of-use primary tariff.	Summer usage – Peak (10am–8pm weekdays)	60.498	c/kWh
		Summer usage – All other times	22.890	c/kWh
		Usage – All other times	22.890	c/kWh
		Daily supply charge	124.936	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	81.906	$/kW
		Chargeable Demand – Off peak	8.230	$/kW
		Usage	16.786	c/kWh
		Daily supply charge	62.723	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	17.913	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	19.268	c/kWh
41	Small business monthly demand primary tariff.	Demand	22.436	$/kW
		Usage	14.961	c/kWh
		Daily supply charge	538.321	c

Large customer tariffs

Tariff	Description	Charge type		Unit
44	Large business monthly demand primary tariff Demand threshold 30 kW.	Chargeable demand	36.288	$/kW
		Usage	12.540	c/kWh
		Daily supply charge	4627.229	c
45	Large business monthly demand primary tariff Demand threshold 120 kW.	Chargeable demand	27.028	$/kW
		Usage	12.540	c/kWh
		Daily supply charge	15302.159	c
46	Large business monthly demand primary tariff Demand threshold 400 kW.	Chargeable demand	22.128	$/kW
		Usage	12.514	c/kWh
		Daily supply charge	40035.224	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	66.777	$/kW
		Peak usage	12.184	c/kWh
		Off-peak chargeable demand	11.562	$/kW
		Off-peak usage	14.664	c/kWh
		Daily supply charge	3626.927	c
51A	Large business high-voltage monthly demand primary tariffs only for customers classified as CAC and supplied at 66kV.	Demand	2.659	$/kVA
		Capacity	4.375	$/kVA
		Excess reactive demand	4.454	$/kvar
		Usage	12.097	c/kWh
		Daily connection charge	10.254	$/unit
		Daily supply charge	25812.003	c

51B	Large business high-voltage monthly demand primary tariffs only for customers classified as CAC and supplied at 33kV.	Demand	2.755	$/kVA
		Capacity	5.396	$/kVA
		Excess reactive demand	4.454	$/kvar
		Usage	12.097	c/kWh
		Daily connection charge	10.254	$/unit
		Daily supply charge	18918.753	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	3.339	$/kVA
		Capacity	6.259	$/kVA
		Excess reactive demand	4.454	$/kvar
		Usage	12.101	c/kWh
		Daily connection charge	10.254	$/unit
		Daily supply charge	17434.053	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	6.736	$/kVA
		Capacity	12.355	$/kVA
		Excess reactive demand	4.454	$/kvar
		Usage	12.120	c/kWh
		Daily connection charge	10.254	$/unit
		Daily supply charge	16585.653	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	6.882	$/kVA
		Excess reactive demand	4.454	$/kvar
		Usage – Summer	11.628	c/kWh
		Usage – All other times	12.040	c/kWh
		Daily connection charge	10.254	$/unit
		Daily supply charge	13086.003	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	4.828	$/kVA
		Excess reactive demand	4.454	$/kvar
		Usage – Summer	11.632	c/kWh
		Usage – All other times	12.044	c/kWh
		Daily connection charge	10.254	$/unit
		Daily supply charge	13086.003	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	8.937	$/kVA
		Excess reactive demand	4.454	$/kvar
		Usage – Summer	11.651	c/kWh
		Usage – All other times	12.063	c/kWh
		Daily connection charge	10.254	$/unit
		Daily supply charge	13086.003	c
53	Large business high-voltage monthly primary tariff only for customers classified as ICC.	Demand	2.659	$/kVA
		Capacity	4.375	$/kVA
		Excess reactive demand	4.454	$/kvar
		Usage	12.097	c/kWh
		Daily supply charge	25622.108	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	28.465	c/kWh
		Daily supply charge	0.525	c/lamp
91	Business flat-rate primary tariff.	Usage	21.831	c/kWh

Part 5—Metering charges

Large customer—type 1, 2, 3, 4 (advanced digital) meters

Description	Charge type	Rate	Unit
Standard asset customer (annual consumption 750MWh or less)	Daily metering charge	160.761	c
Standard asset customer (annual consumption greater than 750MWh)	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[188], 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 37 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	212,237			58	30
T45–median	823,704			204	120
T46–median	2,233,536			526	400

188 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 do not 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 38 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	48.800		8.424		
	Energy			11.606		
	Fixed retail	37.243				
	Variable retail			2.257		
	Standing offer adjustment	4.302		1.114		
	SRES cost pass-through			0.2583		
	Total	90.345		23.661		
Tariff 12A—Residential (seasonal time-of-use)	Network	37.258	41.467	5.182		
	Energy		11.606	11.606		
	Fixed retail	37.243				
	Variable retail		5.981	1.892		
	Standing offer adjustment	3.725	2.953	0.934		
	SRES cost pass-through		0.2583	0.2583		
	Total	78.226	62.265	19.872		
Tariff 14—Residential (seasonal time-of-use demand)	Network	6.350		1.726	50.852	7.303
	Energy			11.606		
	Fixed retail	37.243				
	Variable retail			1.503	5.731	0.823
	Standing offer adjustment	2.180		0.742	2.829	0.406
	SRES cost pass-through			0.2583		
	Total	45.773		15.835	59.412	8.532
Tariff 31—Night rate super economy	Network			6.087		
	Energy			9.024		
	Fixed retail					
	Variable retail			1.703		
	Standing offer adjustment			0.841		

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			0.2583		
	Total			17.913		
Tariff 33—Controlled supply economy	Network			6.401		
	Energy			9.869		
	Fixed retail					
	Variable retail			1.834		
	Standing offer adjustment			0.905		
	SRES cost pass-through			0.2583		
	Total			19.268		

a *Charged per metering point.*

Note: Totals may not add due to rounding.

Table 39 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	13.760	29.389	45.018	60.647	76.276	1.708	8.252
	Energy						11.606	
	Fixed retail	11.336	11.336	11.336	11.336	11.336		
	Variable retail						1.501	0.930
	Standing offer adjustment	1.255	2.036	2.818	3.599	4.381	0.741	0.459
	SRES cost pass-through						0.2583	
	Total	26.351	42.761	59.172	75.582	91.993	15.814	9.641

Note: Totals may not add due to rounding.

Table 40 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	66.200		8.801		
	Energy			11.606		
	Fixed retail	52.787				
	Variable retail			2.612		
	Standing offer adjustment	5.949		1.151		
	SRES cost pass-through			0.2619		
	Total	124.936		24.432		
Tariff 22A—Business (seasonal time-of-use)	Network	66.200	39.252	7.499		
	Energy		11.606	11.606		
	Fixed retail	52.787				
	Variable retail		6.510	2.445		
	Standing offer adjustment	5.949	2.868	1.078		
	SRES cost pass-through		0.2619	0.2619		
	Total	124.936	60.498	22.890		
Tariff 24—Business (seasonal time-of-use demand)	Network	6.949		2.345	69.154	6.949
	Energy			11.606		
	Fixed retail	52.787				
	Variable retail			1.786	8.852	0.889
	Standing offer adjustment	2.987		0.787	3.900	0.392
	SRES cost pass-through			0.2619		
	Total	62.723		16.786	81.906	8.230
Tariff 41—Business low voltage (demand)	Network	459.900		0.804		18.943
	Energy			11.606		
	Fixed retail	52.787				
	Variable retail			1.589		2.425
	Standing offer adjustment	25.634		0.700		1.068
	SRES cost pass-through			0.2619		

Retail tariff	***Tariff component***	***Fixed[a] (c/day)***	***Peak usage (c/kWh)***	***Off-peak/Flat***	***Peak demand ($/kW/mth)***	***Off-peak/Flat demand***
	Total	538.321		14.961		22.436
Tariff 91—Unmetered supply	Network			6.605		
	Energy			11.606		
	Fixed retail					
	Variable retail			2.331		
	Standing offer adjustment			1.027		
	SRES cost pass-through			0.2619		
	Total			21.831		

a *Charged per metering point.*

Note: Totals may not add due to rounding

Table 41 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	4029.100		1.343		32.590
	Energy			9.700		
	Fixed retail	377.785				
	Variable retail			0.667		1.970
	Headroom	220.344		0.586		1.728
	SRES cost pass-through			0.2437		
	Total	4627.229		12.540		36.288
Tariff 45—Business over 100 MWh/yr—Medium (demand)	Network	13534.300		1.343		24.274
	Energy			9.700		
	Fixed retail	1039.185				
	Variable retail			0.667		1.467
	Headroom	728.674		0.586		1.287
	SRES cost pass-through			0.2437		
	Total	15302.159		12.540		27.028
Tariff 46—Business over 100 MWh/yr—Large (demand)	Network	35485.100		1.319		19.873
	Energy			9.700		
	Fixed retail	2643.685				
	Variable retail			0.666		1.201
	Headroom	1906.439		0.584		1.054
	SRES cost pass-through			0.2437		
	Total	40035.224		12.514		22.128
Tariff 50—Business over 100 MWh/yr (seasonal time-of-use demand)	Network	3114.000	1.024	3.251	59.972	10.384
	Energy		9.700	9.700		
	Fixed retail	340.217				
	Variable retail		0.648	0.783	3.625	0.628
	Headroom	172.711	0.569	0.687	3.180	0.551
	SRES cost pass-through		0.2437	0.2437		
	Total	3626.927	12.184	14.664	66.777	11.562

Tariff 71—Street lighting	Network	0.500		15.646		
	Energy			9.700		
	Fixed retail					
	Variable retail			1.532		
	Headroom	0.025		1.344		
	SRES cost pass-through			0.2437		
	Total	0.525		28.465		

a *Charged per metering point.*

Note: Totals may not add due to rounding

Table 42 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 66 kV	Network	21965.900		1.305	9.209	3.929	2.388	4.000
	Energy			9.350				
	Fixed retail	2616.960						
	Variable retail			0.644	0.557	0.237	0.144	0.242
	Headroom	1229.143		0.565	0.488	0.208	0.127	0.212
	SRES cost pass-through			0.2323				
	Total	25812.003		12.097	10.254	4.375	2.659	4.454
Tariff 51B—Business over 4 GWh/yr—High voltage 33 kV	Network	15400.900		1.305	9.209	4.846	2.474	4.000
	Energy			9.350				
	Fixed retail	2616.960						
	Variable retail			0.644	0.557	0.293	0.150	0.242
	Headroom	900.893		0.565	0.488	0.257	0.131	0.212
	SRES cost pass-through			0.2323				
	Total	18918.753		12.097	10.254	5.396	2.755	4.454
Tariff 51C—Business over 4 GWh/yr—High voltage 22/11 kV Bus	Network	13986.900		1.309	9.209	5.621	2.999	4.000
	Energy			9.350				
	Fixed retail	2616.960						
	Variable retail			0.644	0.557	0.340	0.181	0.242
	Headroom	830.193		0.565	0.488	0.298	0.159	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			0.2323				
	Total	17434.053		12.101	10.254	6.259	3.339	4.454
Tariff 51D—Business over 4 GWh/yr—High voltage 22/11 kV Line	Network	13178.900		1.326	9.209	11.096	6.050	4.000
	Energy			9.350				
	Fixed retail	2616.960						
	Variable retail			0.645	0.557	0.671	0.366	0.242
	Headroom	789.793		0.566	0.488	0.588	0.321	0.212
	SRES cost pass-through			0.2323				
	Total	16585.653		12.120	10.254	12.355	6.736	4.454
Tariff 52A—Business over 4 GWh/yr—High voltage 66/3 kV (STOUD)	Network	9845.900	0.884	1.254	9.209	6.181	11.000	4.000
	Energy		9.350	9.350				
	Fixed retail	2616.960						
	Variable retail		0.619	0.641	0.557	0.374	0.665	0.242
	Headroom	623.143	0.543	0.562	0.488	0.328	0.583	0.212
	SRES cost pass-through		0.2323	0.2323				
	Total	13086.003	11.628	12.040	10.254	6.882	12.248	4.454
Tariff 52B—Business over 4 GWh/yr—High voltage 22/11kV Bus (STOUD)	Network	9845.900	0.888	1.258	9.209	4.336	41.435	4.000
	Energy		9.350	9.350				
	Fixed retail	2616.960						
	Variable retail		0.619	0.641	0.557	0.262	2.505	0.242
	Headroom	623.143	0.543	0.562	0.488	0.230	2.197	0.212
	SRES cost pass-through		0.2323	0.2323				

Retail tariff	***Tariff component***	***Fixed[a] (c/day)***	***Peak usage***	***Off-peak/flat***	***Connection unit***	***Capacity***	***Demand***	***Excess reactive***
	Total	13086.003	11.632	12.044	10.254	4.828	46.137	4.454
Tariff 52C—Business over 4 GWh/yr—High voltage 22/11 kV Line (STOUD)	Network	9845.900	0.905	1.275	9.209	8.026	72.333	4.000
	Energy		9.350	9.350				
	Fixed retail	2616.960						
	Variable retail		0.620	0.642	0.557	0.485	4.372	0.242
	Headroom	623.143	0.544	0.563	0.488	0.426	3.835	0.212
	SRES cost pass-through		0.2323	0.2323				
	Total	13086.003	11.651	12.063	10.254	8.937	80.540	4.454
Tariff 53—Business over 40 GWh/yr	Network	21965.900		1.305		3.929	2.388	4.000
	Energy			9.350				
	Fixed retail	2436.108						
	Variable retail			0.644		0.237	0.144	0.242
	Headroom	1220.100		0.565		0.208	0.127	0.212
	SRES cost pass-through			0.2323				
	Total	25622.108		12.097		4.375	2.659	4.454

a *Charged per metering point.*

Note: Totals may not add due to rounding

APPENDIX J: SRES COST PASS-THROUGH

This appendix provides further information about how the SRES pass-through amounts presented in Chapter 6 were calculated.

First, we calculated the actual cost of SRES compliance during 2018–19, based on the final STP for the 2018 and 2019 calendar years—using the same approach employed by ACIL Allen. The STPs are determined by the Clean Energy Regulator.

We then took the difference between the SRES allowance provided in the 2018–19 notified prices and the actual 2018–19 SRES cost. This revealed an SRES under-recovery of approximately $1.920/MWh (0.1920 c/kWh), as shown in the table below.

Table 43 2018–19 SRES under-recovery for all settlement classes

	Period	*STP (%)*[a]		*Clearing house price ($/MWh)*[a]	*SRES cost ($/MWh)*	*2018–19 average SRES cost ($/MWh)*
		Final	*Non-binding*			
2018–19 final determination allowance	1 Jul–31 Dec 2018	17.08%	–	$40.00	$6.832	$5.842
	1 Jan–30 Jun 2019	–	12.13%	$40.00	$4.852	
2018–19 actual cost	1 Jul–31 Dec 2018	17.08%	–	$40.00	$6.832	$7.762
	1 Jan–30 Jun 2019	21.73%	–	$40.00	$8.692	
Under-recovery in 2018–19 (before adjusting for energy losses, variable retail costs, standing offer adjustment/headroom and time value of money)						$1.920

a *Determined by the Clean Energy Regulator.*

Note: For presentation purposes, figures in this table have been rounded. Therefore, these figures may not sum, subtract or multiply exactly.

Next, we made an adjustment to the under-recovery to account for energy losses—to determine the SRES liabilities based on energy acquired. In the 2018–19 price determination, we applied a loss factor to energy purchase costs for each settlement class to reflect transmission and distribution losses. We applied the same loss factors to the under-recovered SRES amounts calculated above, consistent with the 2018–19 price determination.

To restore the real values of the under-recovered amounts, we made an adjustment to reflect the time-value of money for retailers over that 12-month period, proxied by a nominal weighted-average cost of capital of 8.44 per cent.

Finally, we applied the relevant variable retail cost allocators, standing offer adjustment or headroom allowance (which reflect the allowances applying in the year in which the under-recovery was incurred) to arrive at the final SRES pass-through amounts. The result is four discrete pass-through amounts, which are applied at the final stage of the build-up of the 2019–20 notified prices.

The calculations and pass-through amounts to apply to each settlement class are set out in the table below.

Table 44 SRES pass-through amounts for 2019–20 by settlement class

Energex NSLP—residential and controlled load 9000 & 9100	
SRES under-recovery in 2018–19 (c/kWh)	0.1920
+ Energy losses in 2018–19 (total loss factor)	1.062
+ Discount rate (time value of money)	8.44%
Under-recovery before the application of standing offer adjustment and variable retail cost allowance (2018–19 c/kWh)	0.2211
+ Variable retail cost allowance (residential) in 2018–19 (%)	11.27%
+ Standing offer adjustment in 2018–19 (%)	5.0%
SRES cost pass-through for 2019–20 (c/kWh)	0.2583
Energex NSLP—small business and unmetered supply	
SRES under-recovery in 2018–19 (c/kWh)	0.1920
+ Energy losses in 2018–19 (total loss factor)	1.0620
+ Discount rate (time value of money)	8.44%
Under-recovery before the application of standing offer adjustment and variable retail cost allowance (2018–19 c/kWh)	0.2211
+ Variable retail cost allowance (residential) in 2018–19 (%)	12.80%
+ Standing offer adjustment in 2018–19 (%)	5.0%
SRES cost pass-through for 2019–20 (c/kWh)	0.2619
Ergon Energy NSLP—SAC demand and street lighting	
SRES under-recovery in 2018–19 (c/kWh)	0.1920
+ Energy losses in 2018–19 (total loss factor)	1.051
+ Discount rate (time value of money)	8.44%
Under-recovery before the application of standing offer adjustment and variable retail cost allowance (2018–19 c/kWh)	0.2188
+ Variable retail cost allowance (residential) in 2018–19 (%)	6.0445%
+ Headroom allowance in 2018–19 (%)	5.0%
SRES cost pass-through for 2019–20 (c/kWh)	0.2437
Ergon Energy NSLP—high voltage—ICC and CAC	
SRES under-recovery in 2018–19 (c/kWh)	0.1920
+ Energy losses in 2018–19 (total loss factor)	1.002
+ Discount rate (time value of money)	8.44%
Under-recovery before the application of standing offer adjustment and variable retail cost allowance (2018–19 c/kWh)	0.2086
+ Variable retail cost allowance (residential) in 2018–19 (%)	6.0445%
+ Headroom allowance in 2018–19 (%)	5.0%
SRES cost pass-through for 2019–20 (c/kWh)	0.2323