Queensland Competition Authority

Draft determination

Regulated retail electricity prices for 2021–22

Regional Queensland

March 2021

Level 27, 145 Ann Street, Brisbane Q 4000
GPO Box 2257, Brisbane Q 4001
Tel (07) 3222 0555
www.qca.org.au

Submissions

Closing date for submissions: 23 April 2021

Public involvement is an important element of the decision-making processes of the Queensland Competition Authority (QCA). Therefore, submissions are invited from interested parties concerning its assessment of regulated retail electricity prices for regional Queensland in 2021–22. The QCA will take account of all submissions received within the stated timeframes.

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

Queensland Competition Authority
GPO Box 2257
Brisbane Q 4001
Tel (07) 3222 0555
Fax (07) 3222 0599
www.qca.org.au/submissions

Confidentiality

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

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

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

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

Public access to submissions

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

CONTENTS

1 ABOUT OUR REVIEW

1.1 What have we been asked to do?

On 8 January 2021, we received a delegation from the Minister for Energy, Renewables and Hydrogen (the Minister) to set regulated retail electricity prices (notified prices) to apply in regional Queensland in 2021–22.

We are delegated this task by the Minister in accordance with s. 90AA of the *Electricity Act 1994* (Qld) (Electricity Act).

1.2 Scope of the review

This review is limited to setting the 2021–22 notified prices. As we set prices under a delegation from the Minister, the relevant legal framework that applies to the Minister when setting notified prices also applies to us. The framework is contained in the Electricity Act and sets out factors[1] we must have regard to when making a price determination. These are:

- the actual costs of making, producing or supplying the goods or services
- the effect of the price determination on competition in the Queensland retail electricity market
- any matter we are required by delegation to consider.

We may also have regard to any other matter we consider relevant.[2]

Matters we must consider under the delegation

The Minister's delegation includes terms of reference, which provides matters relevant to our price determination this year, namely:

- the period—the price determination applies from 1 July 2021 to 30 June 2022
- the timeframes—we must publish the draft price determination by March 2021 and the final determination by 11 June 2021[3]
- particular policies or principles—we must have regard to, among other matters, the Queensland Government's Uniform Tariff Policy (UTP)
- the pricing methodology—we must use the network plus retail (N+R) cost build-up methodology to set notified prices
- consultation—we must consult at various stages before we make the final price determination and consider the merits of undertaking additional consultation, e.g. holding stakeholder workshops on key issues.

A copy of the delegation, including the terms of reference, is provided in Appendix A.

[1] Section 90(5)(a) of the Electricity Act.
[2] Section 90(5)(b) of the Electricity Act.
[3] Appendix A: Minister's delegation, terms of reference, clause 15.

1.3 Review process and consultation

Interim consultation paper

On 12 January 2021, we released an interim consultation paper (ICP) and invited stakeholders to comment on key issues relevant to this year's price determination.

In response, we received 5 stakeholder submissions.[4]

Draft determination

This draft determination contains draft notified prices, presented as bundled prices appropriate to the retail tariff structure (except for site-specific tariffs).[5]

In making this draft determination, we have had regard to relevant factors in the Electricity Act, matters in the delegation, stakeholder submissions on the ICP, as well as our own analysis.

We invite stakeholders to comment on matters in this draft determination. Information on making a submission is available on our website.[6]

Submissions on the draft determination are due by 23 April 2021.

We will consider all stakeholder submissions received by the due date, along with other relevant information, when making our final determination on notified prices.

Key dates

We are currently mid-way through the review process. The key review dates from here, including when we intend to hold the stakeholder workshop[7] and publish our final determination, are provided below.

We encourage stakeholders to subscribe to our email alerts to keep up to date with the latest developments on this project.

[4] Stakeholder submissions are available on our website.
[5] As required in cl. 8 of the terms of reference (Appendix A).
[6] Our submission policy and online submission form are available on our website.
[7] Stakeholder workshop information and the registration form is available on our website.

1.4 Human Rights Act declaration

As required by s. 58 of the *Human Rights Act 2019* (Qld) (Human Rights Act), we have considered the compatibility of our determination with human rights. Our determination relates to the prices that individuals, in their capacity as consumers, pay for the supply of electricity; therefore, we consider that the following human rights may potentially be relevant:

- equality and non-discrimination
- protection of families and children.

When setting notified prices, we have had regard to, among other things, the Queensland Government's UTP, which provides that:

> wherever possible, customers of the same class should pay no more for their electricity, and should pay for their electricity via similar price structures, regardless of their geographic location. However, the UTP should not limit regional customers accessing a wider choice of prices and price structures than may be available within SEQ (the Energex distribution area).

Because of this policy, the electricity prices for most customers in regional Queensland are set at a level lower than the actual cost of supply. The above-mentioned rights have therefore not been limited by our decision.

We are of the view that this price determination is compatible with human rights under s. 8(a) of the Human Rights Act.

1.5 Report structure

The draft determination is structured as follows:

- Indicative bill impacts of draft notified prices (chapter 2)
- Overarching framework (chapter 3):
  - Context (section 3.1)
  - Approach for setting prices, including for new retail tariffs (section 3.2 and 3.3)
  - Other matters, including tariff schedule terms and conditions (section 3.4)
- Cost build-up components—individual cost elements (chapter 4)
  - Network component (section 4.1)
  - Retail component (section 4.2)
    - Energy costs (section 4.2.1)
    - Retail costs (section 4.2.2)
- Other costs and pricing issues (chapter 5)
- Draft notified prices (chapter 6).

1.6 Supporting documents

Information booklet

An information booklet accompanies this paper. It provides an ‘at a glance’ overview of the price-setting process and draft notified price bill impacts (as contained in this report)—it aims to help stakeholders become quickly informed of the key issues and is designed to be read in conjunction with the draft report (not as a substitute).

Consultant's reports

We engaged ACIL Allen to assist us set the energy and retail cost components of notified prices this year. ACIL Allen provided:

- a report on energy cost (discussed in section 4.2.1)
- a report on retail costs (discussed in section 4.2.2).

Both reports are published on our website.

Technical appendices

Supporting information is provided in the following appendices:

- Appendix A: Minister's delegation
- Appendix B: Stakeholder submissions and references
- Appendix C: Energy cost approach
- Appendix D: Retail cost approach
- Appendix E: Cost pass-through approach
- Appendix F: DMO bill comparison and adjustment
- Appendix G: Data used to estimate customer impacts
- Appendix H: Build-up of draft notified prices
- Appendix I: Draft gazette notice

2 INDICATIVE BILL IMPACTS

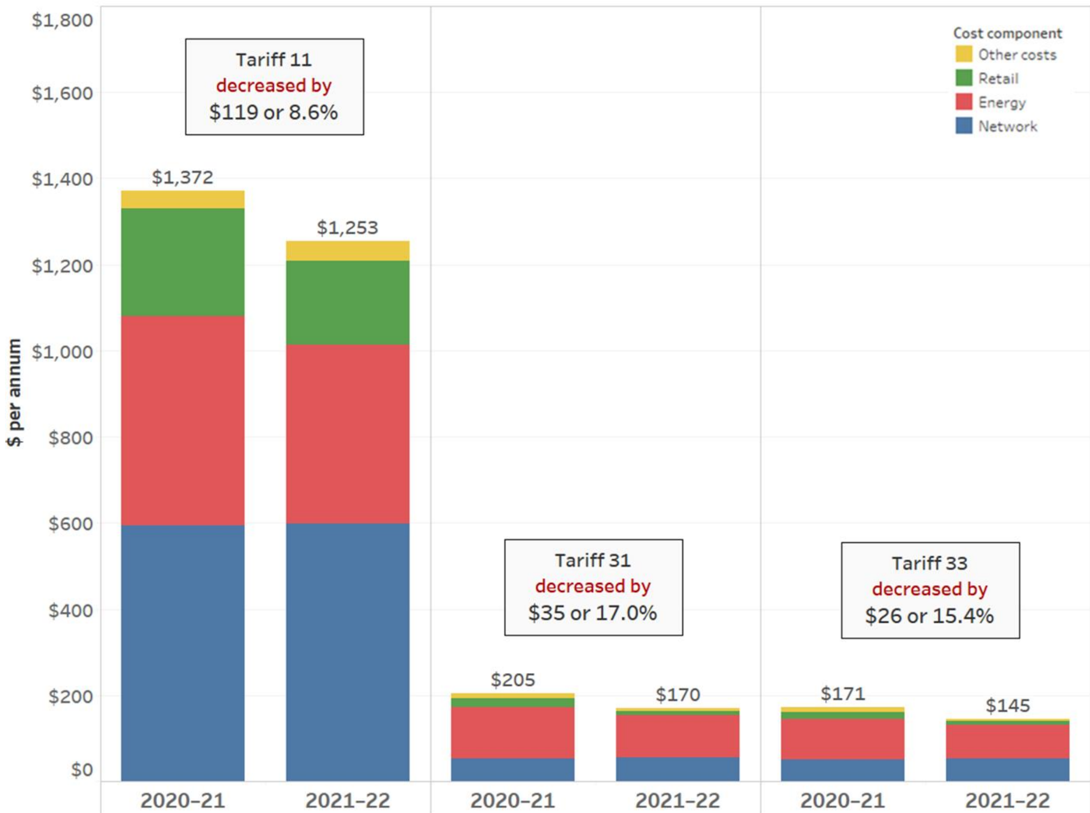
Overall, typical customers[8] on all major tariffs can expect a decrease in their electricity bill this year based on the draft notified prices.[9] The decrease is largely due to a decline in estimated retail and energy costs.[10] The charts provided show bills for a typical customer based on the draft notified prices, compared to bills based on the current (2020–21) notified prices.

Importantly, an individual customer's actual bill will vary depending on how much electricity they use. We strongly recommend that customers engage with their retailer for further advice and information reflecting their individual circumstances.

2.1 Residential customers

Typical customers on the main residential tariffs (tariffs 11, 31 and 33)[11] are expected to pay around 8.6 to 17 per cent less for their electricity in 2021–22 (see figure below).[12]

Figure 2.1 Bills for typical residential customers, 2020–21 and 2021–22 (incl. GST)



Note: Amounts are rounded to the closest dollar. Therefore, amounts presented may not add precisely. Percentage changes are based on unrounded amounts.

[8] The typical customer for a given tariff is the median or middle customer in terms of consumption among all customers on the same tariff in regional Queensland. Typical customer consumption data were provided by Ergon Retail (see Appendix G).

[9] The draft notified prices are set out in chapter 6.

[10] Individual cost components of notified prices are discussed in chapter 4.

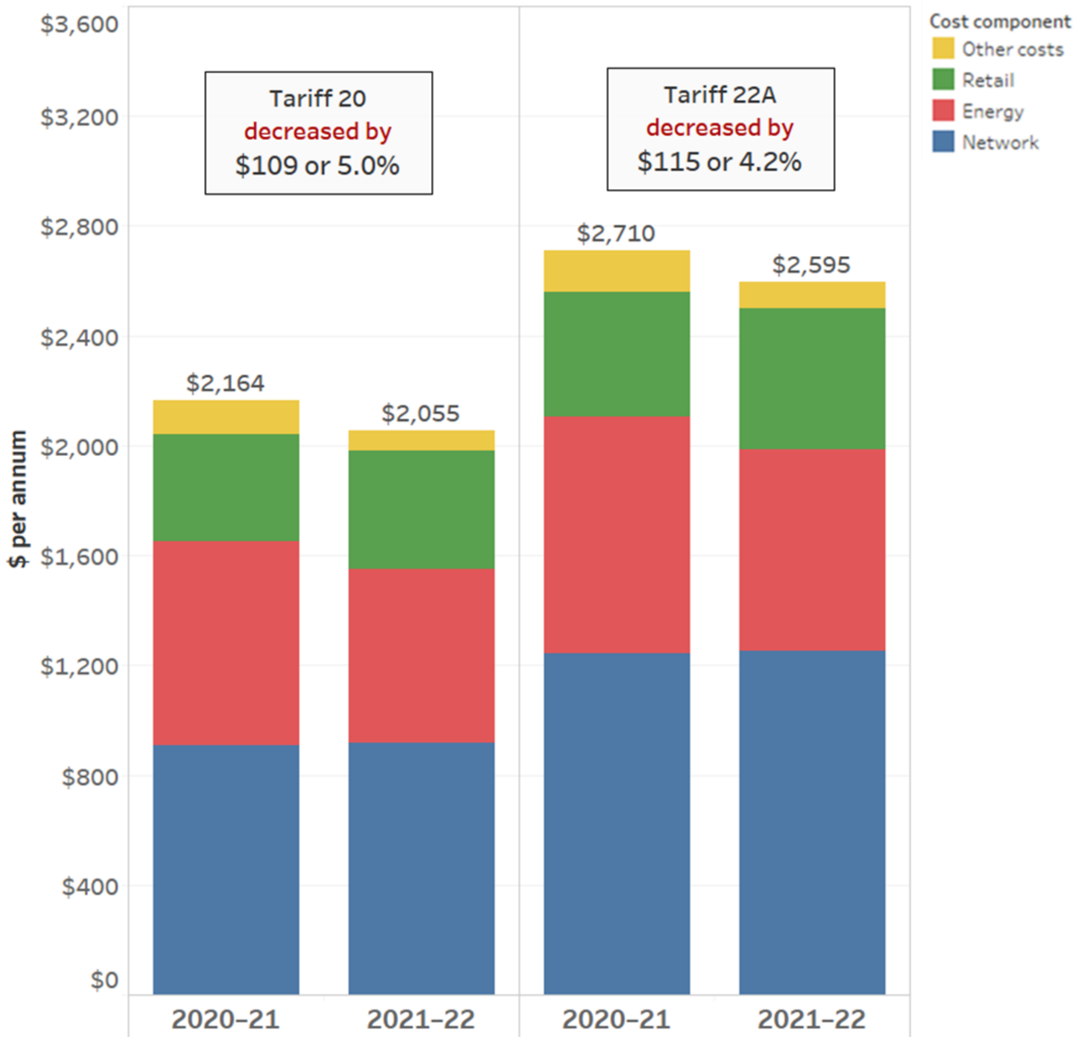
[11] Most residential customers are on tariff 11, but many customers also access load control tariffs—tariffs 31 and 33—for appliances that do not require a constant supply of electricity (e.g. hot water systems and pool pumps).

[12] Metering charges are excluded from the bill impact analysis due to the variety of different metering arrangements that a customer may have.

2.2 Small business customers

Typical customers on the main small business tariffs (tariffs 20 and 22A)[13] are expected to pay around 4.2 to 5 per cent less for their electricity in 2021–22 (see figure below).[14]

Figure 1.2 Bills for typical small business customers, 2020–21 and 2021–22 (incl. GST)



Note: Amounts are rounded to the closest dollar. Therefore, amounts presented may not add precisely. Percentage changes are based on unrounded amounts.

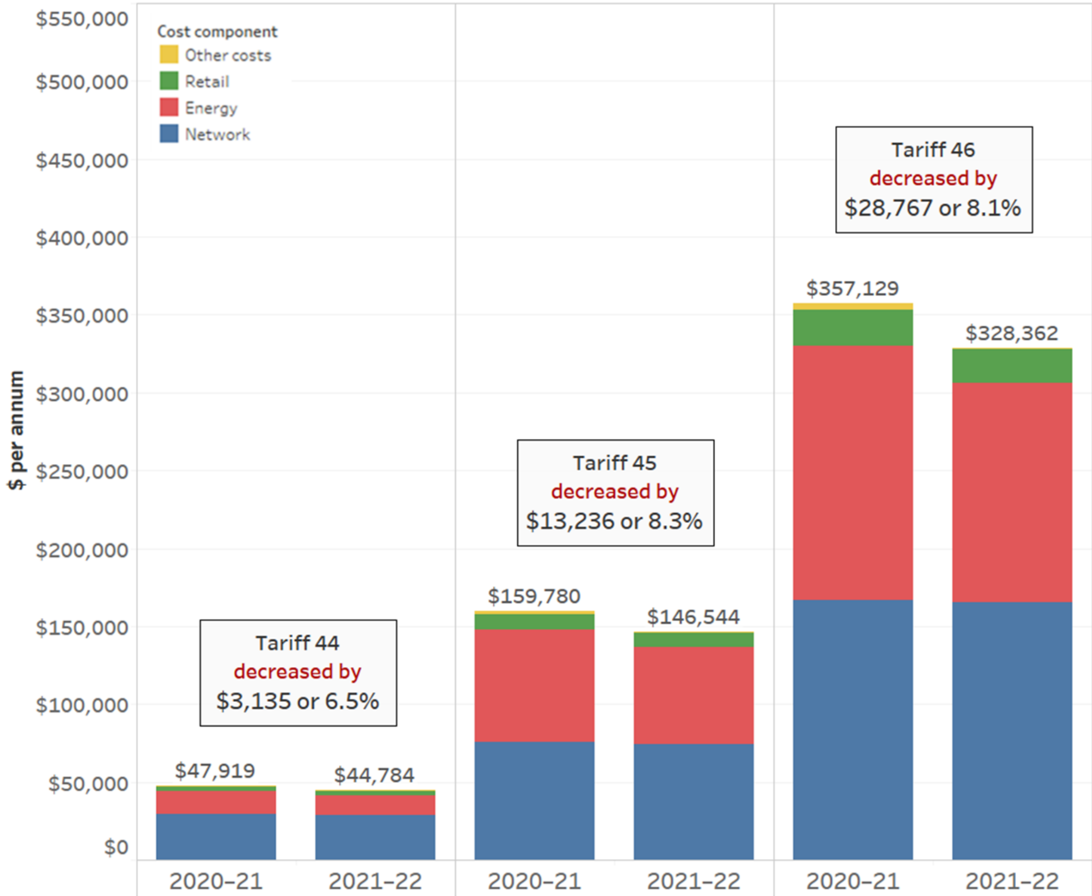
[13] Tariff 20 is a flat-rate tariff, and tariff 22A is a time-of-use tariff.

[14] Metering charges are excluded from the bill impact analysis due to the variety of different metering arrangements that a customer may have.

2.3 Large business customers

Typical customers on tariff 44, 45 or 46 are expected to pay around 6.5 to 8.3 per cent less for their electricity in 2021–22 (see figure below).[15]

Figure 2.2 Bills for typical large business customers, 2020–21 and 2021–22 (incl. GST)



Note: Amounts are rounded to the closest dollar. Therefore, amounts presented may not add precisely. Percentage changes are based on unrounded amounts.

[15] Metering charges are excluded from the bill impact analysis due to the variety of different metering arrangements that a customer may have.

3 OVERARCHING FRAMEWORK

This chapter provides our draft views on key issues to consider in this year's price determination, including overarching framework matters that impact how we set notified prices.

The key issues consist of matters included in the Minister's delegation (and terms of reference) we must consider when setting notified prices. For instance, the Minister has provided broad considerations we must have regard to when setting notified prices and specific considerations impacting how we set the new retail tariffs. We must also have regard to matters affecting the terms and conditions for accessing tariffs contained in the tariff schedule.[16]

Beyond this, there are other matters relevant to setting notified prices. For instance, we have discussed how particular policies may be considered and applied.

The matters discussed are:

- the context for this price review (section 3.1)
- the approach for setting notified prices, including specific considerations for new retail tariffs (sections 3.2 and 3.3)
- other matters, including metering and tariff terms and conditions (section 3.4).

3.1 Context

In recent years, the electricity sector has been undergoing substantial structural reforms. The reforms are expected to have ongoing impacts on the electricity market environment, including how market participants operate and manage risks.

This year, the key factors directly impacting the electricity market in Queensland include:

- the default market offer (DMO) for south east Queensland (SEQ)—the Australian Energy Regulator (AER) sets DMOs that limit the prices charged to small customers on standard retail contracts. The DMO was first introduced in 2019–20. The AER is expected to set the DMOs for the coming year in April 2021
- the ongoing network tariff reforms—the AER sets network revenues and tariffs for energy distributors in Queensland, namely Energex and Ergon Distribution (the distributors). As part of the 2020–25 regulatory determination process, the AER approved new network tariffs for distributors with more complex structures aimed at facilitating a move towards greater cost reflectivity. A number of new tariffs have already been introduced (and commenced on 1 July 2020) and additional tariffs have been considered in this review, to be introduced (and commence) on 1 July 2021[17]
- the five-minute settlement reform—the Australian Energy Market Commission (AEMC) made a rule in 2017 to change the financial settlement period for wholesale electricity spot prices from 30 minutes to 5 minutes, commencing on 1 October 2021. The AEMC indicated this would provide better price signals for investment in fast-response technologies in the National Electricity Market (NEM), such as batteries, demand response and new generation

[16] The current 2020–21 tariff schedule of regulated retail electricity prices is available on our website.
[17] More information on the new tariffs is contained in section 3.3.

gas peaking plants. This reform is likely to affect the operation of the NEM, the availability of ASX financial products and wholesale energy costs (section 4.2.1 and Appendix C).

The Minister's letter and delegation refers to the DMO and network reforms as important considerations this year, with additional matters included in the delegation to reflect this. We have also considered the effects of the five-minute settlement reform on wholesale energy costs (see section 4.2.1).

3.2 Approach for setting notified prices

Matters in the delegation

When setting notified prices, the delegation requires us to consider:

- the Queensland Government's UTP, which provides that wherever possible, customers of the same class should pay no more for their electricity, and should pay for their electricity via similar price structures, regardless of their geographic location. However, the UTP should not limit regional customers accessing a wider choice of prices and price structures than may be available within SEQ (the Energex distribution area)
- using the N+R cost build-up methodology, including applying this approach flexibly for setting some small customer retail tariffs (i.e. 12A, 14, 22A, and 24).[18]

The delegation also requires us to consider:

- maintaining all existing standard tariffs in the current tariff schedule, including price structures and access criteria (unless otherwise set out in the delegation)
- introducing new retail tariffs, based on specific new network tariffs approved by the AER
- specific cost considerations for the new retail tariffs.

The delegation is broadly consistent with previous years and our approach to setting notified prices in previous price determinations—with some new matters relevant to setting the new retail tariffs.

On that basis, we are considering approaches for setting notified prices that take into account these matters, including having regard to the government's UTP and using the N+R cost build-up methodology to set notified prices.

The matters relevant to setting the new retail tariffs, as well as stakeholders' comments on this, are discussed separately in section 3.3.

Stakeholder comments

Several stakeholders said the cost of electricity continues to be a key issue in regional Queensland and, while steps have been taken to improve electricity prices in Queensland, a number of network reform issues are to still be addressed and pricing structures could be more simplified and transparent, so customers can more easily make informed business decisions.[19]

EQ supported the continued use of the N+R approach to set prices, including taking account of the UTP for small and large customers in the usual manner. EQ also said:

[18] Appendix A: Minister's delegation, terms of reference, clause 2(e).
[19] Canegrowers, sub. 6, pp. 3,2, ii and 7, QFF, sub. 1, p. 4.

- in the interests of efficiency and to reduce customer confusion, there is a strong need to rationalise the existing retail tariff suite, in particular EQ:
  - queried the need for tariff 20A, as there has been no customer interest in this tariff since it was introduced
  - recommended closing off tariffs 12A, 14, 22A, 24 and 41 and making these tariffs obsolete in future, as there are limited customers on these tariffs and customers now have substantial choice and other retail tariff options. This would also reduce the need to use the flexible N+R approach to set these tariffs, which have no underlying network tariff
- an alternative approach to setting R under the N+R framework should be considered that provides better price signals to customers.[20]

Analysis and draft position

Having regard to the relevant factors, stakeholder comments and our own analysis, we have set notified prices having regard to:

- the Queensland Government's UTP cost considerations, that means basing prices on:
  - for small customers—the costs of supply in SEQ (Energex pricing region)
  - for large business customers—the costs of supply in the Ergon Distribution pricing region with the lowest cost of supply that is connected to the NEM—that is, east zone, transmission region one
- the Queensland Government's UTP tariff structure considerations, that means:
  - maintaining existing retail tariffs and structures
  - introducing new retail tariffs based on new network tariff structures
- the N+R methodology for building up notified prices:
  - under the standard approach—using the network tariffs as the basis for determining the structure of retail tariffs (i.e. passing through the N component) and adding the R component (i.e. energy and retail costs) determined by us
  - under the more flexible approach—for retail tariffs that do not have an underlying network tariff, using a price indexation methodology to determine the N component and adding the R component (i.e. energy and retail costs) determined by us.

This approach is consistent with previous years and our approach to setting notified prices in previous price determinations. This approach has benefited most customers in regional Queensland through:

- lower electricity prices—having regard to the UTP allows us to set notified prices for most customers at a level lower than the actual cost of supply. The cost difference is met by the Queensland Government through the payment of a community service obligation subsidy to Ergon Energy Queensland (expected to be $454 million in 2020–21)[21]
- continued access to some of the less common small customer retail tariffs—the additional flexibility provided under the N+R approach last year allowed us to set notified prices for

[20] EQ, sub. 3, pp. 5, 12, 17.
[21] Queensland Government, *Budget Strategy and Outlook 2020–21*, Budget Paper 2, 2020, p. 200.

retail tariffs that no longer have an underlying network tariff on which to base the network costs under the standard N+R approach

- increased tariff optionality—several new tariffs have been introduced based on corresponding new network tariffs arising from the network tariff reforms, including the three new load control tariffs that commenced in November 2020, a suite of eight additional retail tariffs that commenced in January 2021[22], and four new retail tariffs we propose to introduce in this price determination to commence in July 2021.

While there is likely merit in undertaking a review of the suite of retail tariffs as EQ suggested, we consider it premature to do this now (as part of this price review). We note:

- the suite of retail tariffs also includes new tariffs, many of which only became operational on 1 January 2021
- some new retail tariffs have not yet commenced (i.e. the four new retail tariffs we propose to introduce will commence from 1 July 2021)
- the Minister indicated, as part of the last price review, that providing customers with increased options is important, including by developing and continuing to offer additional retail price structures to customers in regional Queensland even if those are not available in SEQ.[23]

That said, in future it would be possible to assess the suite of retail tariffs as a whole, with a view to consolidating the suite of tariffs, including removing tariffs if there is no continuing need or customer interest in them. If delegated the task, this type of review could occur in future price determinations.

3.3 New retail tariffs

3.3.1 New transitional retail tariffs

The delegation requires us to consider introducing three new retail tariffs based on new transitional network tariffs to be approved by the AER. These are described in Ergon Distribution's 2020–25 tariff structure statement (TSS) as:

- Transitional Network ToU Energy Tariff 1
- Transitional Network ToU Energy Tariff 2
- Transitional Network Dual Rate Demand Tariff 3.

According to Ergon Distribution's TSS[24], these network tariffs:

- will commence from 1 July 2021 and are intended to mirror the tariff structure of obsolete retail tariffs 62, 65 and 66 (due to expire on 30 June 2021)
- will be grandfathered immediately, available to existing small business customers in Ergon Distribution's east zone that accessed the corresponding obsolete retail tariff between 1 July 2017 and 30 June 2020.

[22] For more information on the new load control tariffs and the suite of eight additional retail tariffs, see our Supplementary notified price determination 2020–21.
[23] See the Minister's cover letter and delegation to the QCA, 2020–21 supplementary notified price review June 2020.
[24] Ergon Energy, *Ergon Energy Tariff Structure Statement 2020–25*, June 2020 (Erratum: version 6, August 2020, pp. 24–25).

When setting these tariffs, the delegation contains specific matters we must consider:

- the price level—basing the network cost component on the relevant Ergon Distribution network charges for the Ergon Distribution east zone, transmission region one to ensure pricing consistency with the application of the AER's approved network tariff transition pathway as customers move to more cost reflective tariffs
- the terms and conditions—incorporating the grandfathering arrangements for the network tariffs approved by the AER and not applying the geographical limitations of the network tariffs (which limit access to customers in Ergon Distribution east zone); instead, these tariffs should be available to eligible customers across the Ergon Distribution area.

On that basis, we are considering approaches for setting these new retail tariffs that take into account the broader approach to setting notified prices (discussed in section 3.2) and the additional matters in the delegation set out above.

Stakeholder comments

Stakeholders were concerned that we had not provided detailed information on the new tariffs during the initial stage of this review, particularly on the new transitional tariffs we have been asked to introduce.[25] Further, stakeholders said there was a lack of clarity and ongoing confusion surrounding the new tariff arrangements and requested us to provide more information and undertake additional consultation before making the draft determination.[26]

Canegrowers noted that our review timeframe (underway before the submission and approval of Ergon Distribution's annual pricing proposal) impacted the information available and customers' ability to assess the impacts of the new tariffs. Canegrowers said it will review our assessment of this in the draft report and, depending on how the outstanding issues are resolved, there may be a case for retaining the existing obsolete tariffs.[27]

In addition, stakeholders provided specific comments on the prices and terms and conditions associated with the new tariffs:

- Canegrowers said we should retain transitional tariffs that contain deep price reductions at least until the end of the current regulatory pricing period (2025), reflecting both network and retail price profiles associated with electricity used for irrigation. In addition, the charging windows (tariff structures) should be changed, as they are not cost reflective because they do not reflect operational demand during those times.[28]
- Cotton Australia and QFF said that large customers who have accessed the obsolete retail tariffs from 1 July 2017 should not be excluded from accessing these new transitional tariffs, citing affordability concerns[29], and confusion and inequity caused by this differential treatment.[30]
- EQ considered that backdating eligibility for the transitional tariffs to 1 July 2017 may be problematic for retailers and confusing for customers. It suggested we explore alternative options, such as backdating the tariff to when it was made obsolete, or allowing access to

[25] QFF, sub. 1, pp. 2–3; Cotton Australia, sub. 5, p. 2; Canegrowers, sub. 6, p. 3.
[26] Cotton Australia, sub. 5, pp. 2–4; QFF, sub. 1, pp. 2–3.
[27] Canegrowers, sub. 6, pp. 2–3, attachment p. 2.
[28] Canegrowers, sub. 6, p. 1, attachment, pp. 5–6.
[29] Cotton Australia, sub. 5, p. 3.
[30] QFF, sub. 1, pp. 2–3.

those customers who were supplied on an irrigation tariff as at 30 June 2021, which it said may be simpler to implement.[31]

Analysis and draft position

Having regard to the relevant factors, we have set the new retail tariffs having regard to the overarching framework and additional matters in the delegation. The key matters forming part of our assessment are:

- information and timing
- pricing approach
- terms and conditions.

Information and timing

We appreciate stakeholders' concerns that further detail on the new transitional retail tariffs was not provided earlier in this price review—for example, to provide customers with the opportunity to compare the impacts of different tariff options on their bills.

However, we can only assess, provide and consult on the information that is available to us. In relation to these new tariffs, we have relied on:

- Ergon Distribution's TSS[32], which was approved by the AER in June 2020. This contains details on the tariff structures for the new transitional network tariffs, as well as eligibility and customer access arrangements for these tariffs.
- information from EQ—as network prices are yet to be approved by the AER, EQ provided draft network prices to be submitted to the AER for approval (as part of Ergon Distribution’s annual price setting process). At this time, EQ has not formally submitted its pricing proposal to the AER, but is expected to do so in March 2021. We understand the AER expects to make its decision on the proposal and prices for the coming year around May 2021.

Further information on relevant network prices and terms and conditions made available as part of the AER's annual price setting process will be taken into account, where possible, as part of the final determination. We will inform stakeholders where information used in this draft report has changed to reflect updated information in the final determination.

We strongly recommend to customers that they engage directly with Ergon Energy Retail for advice and information on whether the new tariffs would be a suitable option.

Pricing approach

We have set the new transitional retail tariffs:

- price level—based on the relevant Ergon Distribution network prices for the east zone transmission region one region to be approved by the AER
- using the N+R methodology—building up notified prices using the new network tariffs as the basis for determining the structure of retail tariffs (i.e. passing through the N component) and adding the R component (i.e. energy and retail costs) determined by us.

[31] EQ, sub. 3, p. 4.

[32] The AER published its final revenue and network tariff determinations for Ergon Distribution on 5 June 2020. The AER subsequently approved the 2020–21 network pricing proposal of Ergon Distribution on 30 June 2020.

While the new transitional tariffs are set in a similar manner to other notified prices, the cost considerations are different, i.e. the usual approach under the UTP for small customers bases network costs on Energex network prices.

However, we consider basing the network costs on the relevant Ergon Distribution network prices is appropriate. The circumstances are unique in this case in that the tariffs:

- are transitional in nature, replacing expiring obsolete farming and irrigation retail tariffs
- only available to certain customers
- reflect the AER's approved network tariff transition pathway for these customers.

In addition, the network tariffs are specific to Ergon Distribution and are not available in SEQ, so there would be no clear basis on which to determine an equivalent cost base in SEQ (like we do for other small customer tariffs).

We are mindful that customers on obsolete tariffs, including agricultural and irrigation customers, are keen to assess how the new transitional tariffs compare to their existing tariffs. Also, stakeholders said the new transitional tariffs should retain deep price reductions currently built into obsolete tariffs and suggested changes to the tariff structure (charging windows) that will apply.

Importantly, customers should note:

- these transitional network tariffs are new tariffs; they are not a continuation of the obsolete retail tariffs (which have been in the process of being phased out for eight years and are set to expire on 30 June 2021)
- while there are similarities between these sets of tariffs (i.e. they have been designed to mirror the tariff structures[33] of the relevant obsolete retail tariffs (tariffs 62, 65 and 66) and access is linked to use of those obsolete tariffs), there are differences, including in customer eligibility and pricing levels.

Consistent with the scope and overarching framework for our review, we will have regard to the network prices and tariff structures approved by the AER for Ergon Distribution. We cannot review (or amend) the network price levels or tariff structures, as Canegrowers suggested.

In addition, we do not consider it appropriate to establish retail tariffs that differ from their corresponding network tariff. It would rely on departing from the usual approach for setting notified prices and part of the design of the transitional network tariffs is that each tariff structure (charging windows) mirrors those used for the relevant obsolete retail tariffs.

However, the reduced peak charging window suggested by Canegrowers is used in other retail tariffs (e.g. the small business time-of-use monthly demand tariff and the small business time-of-use inclining band tariff). As such, customers currently on the obsolete retail tariffs (or considering accessing these new transitional tariffs) should consult Ergon Energy Retail on the tariff options available and consider whether they would benefit from moving to other tariffs with charging windows more suitable to their circumstances.

[33] Note, the new AER approved structure for the network tariff that mirrors obsolete tariff 66 has a monthly dual-rate capacity charge (for the first 7.5kW and remaining kW), instead of an annual dual-rate capacity charge.

Terms and conditions

We have incorporated terms and conditions for the new retail tariffs based on the corresponding network tariff requirements (including grandfathering arrangements), apart from the geographic limitations of the network tariffs.

This is consistent with the general approach we apply when establishing new retail tariffs based on network tariffs—that is, by passing through network tariff requirements unless there is sufficient justification for why certain requirements should not be applied at the retail level. We took this approach in the last price determination when introducing other new retail tariffs based on relevant network tariffs.

Consistent with the delegation, we have not applied the geographic limitations for the network tariffs at the retail-level (which would result in these tariffs being available only for customers in Ergon Distribution's east zone). We consider small customers outside of this zone, who would otherwise meet the eligibility criteria for the transitional tariffs, should not be treated differently than those in the east zone. EQ has not raised any issues or concerns about not passing through to the retail-level this geographic element of the network tariff requirements.

Stakeholders requested that the transitional tariffs be made available to existing large business customers who have accessed one of the relevant obsolete retail tariffs during the relevant period. However, the non-inclusion of large business customers is part of the design of the network tariffs, and we do not consider it appropriate to expand the scope of the retail tariffs into customer classes that go beyond what was planned at the network level. While this will mean there will be existing large business customers accessing one of the obsolete retail tariffs who will not be able to access the new transitional tariffs, as noted above, these are new tariffs, which are not a continuation of the obsolete retail tariffs. We encourage these customers to contact Ergon Energy Retail and explore the alternative retail tariffs available to them.

We intend to apply the grandfathering arrangements of the corresponding network tariffs to these retail tariffs, noting these are yet to be finalised and approved by the AER.[34] Based on the approved TSS and subsequent information provided by EQ, we understand this will mean:

- existing small business customers will be eligible to access the retail tariff if they accessed the corresponding obsolete retail tariff 62, 65 or 66[35] at some point between 1 July 2017 and 30 June 2020. This means a customer does not need to be currently on the obsolete tariff to opt in to the new retail tariff, provided they accessed the obsolete tariff at some point in that period
- once a customer has accessed the transitional tariff, if the customer switches to another tariff in future, they will not be able to switch back to the transitional tariff.

We have considered EQ's comments regarding alternative options to backdating eligibility for these tariffs, including allowing access to those customers who were supplied on the relevant obsolete tariff as at 30 June 2021. However, consistent with the N+R approach, our position is to apply the grandfathering arrangements in place at the network level, which means allowing customers to opt in to these new tariffs even if they are not currently on the corresponding obsolete tariffs (provided they accessed the obsolete tariff at some point between 1 July 2017 to 30 June 2020).

[34] see Appendix I for the draft tariff schedule and the detailed terms and conditions of these tariffs.
[35] The new retail tariffs that correspond with the obsolete tariffs will be Tariffs 62A, 65A and 66A (respectively).

We note the transitional network tariffs are set to be in place for the remainder of the AER's 2020–25 regulatory control period (as set out in Ergon Distribution's TSS). However, whether they extend beyond this will depend on the arrangements Ergon Distribution proposes, and the AER approves, for Ergon Distribution for the next regulatory control period (2025–30).

As such, we have not specified a date for which these retail tariffs will be discontinued. These arrangements will need to be considered in the context of the underlying network tariff arrangements in future pricing reviews.

3.3.2 Other new retail tariffs

The delegation requires us to consider two other new retail tariffs based on the following network tariffs from Ergon Distribution's TSS:

- Business customer (Basic)>100 MWh pa network tariff
- Residential customer (Basic)>100 MWh pa network tariff.

In addition, we must consider introducing a retail tariff based on the business variant of this network tariff, but only introduce the retail tariff based on the residential variant if there is a need for it at the retail level.[36] The delegation states this will avoid inequitable outcomes for large residential customers based on the type of meter they have and is appropriate given the range of tariffs already available to these customers.[37] If the residential tariff is introduced, the delegation requires us to consider making it accessible to eligible customers on a voluntary basis only.

These network tariffs are similar in nature and apply to business or residential customers with basic metering and with energy consumption greater than 100 MWh per year. Ergon Distribution's TSS describes that the tariffs are being developed to address concerns about the efficiency of pricing arrangements at the distribution level for customers in these circumstances (some of which are likely to be embedded networks).[38]

The network tariffs are set to commence from 1 July 2021, with the price level and structure of these tariffs to be approved by the AER as part of Ergon Distribution's annual pricing proposal for 2021–22.[39]

Stakeholder comments

Stakeholders did not express support for introducing a retail tariff based on the residential network tariff variant, with EQ considering there would be no benefit and limited (if any) customer uptake for this tariff.[40]

CPAQ requested that caravan parks operating embedded networks be excluded from large customer tariffs, due to the price impact of these tariffs and the difficulties there may be for customers of these embedded networks to purchase their electricity from an energy retailer.[41]

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[36] Appendix A: Minister's delegation, terms of reference, clause 2(d).
[37] Appendix A: Minister's delegation, terms of reference, clause 2(d).
[38] AER, *Ergon Energy distribution determination*, final decision, June 2020, attachment 18: tariff structure statement, pp. 25–26.
[39] Ergon Distribution 2020–25 TSS (August erratum), pp. 27–28.
[40] EQ, sub. 3, p. 5.
[41] CPAQ, sub. 2, pp. 4–5.

Analysis and draft position

Having regard to relevant factors, we have introduced a retail tariff based on the new business customer network tariff, but not on the new residential customer network tariff.

Consistent with the N+R framework, the tariff structure of this tariff will be based on the network price and tariff structure approved by the AER. We have made our draft determination using the latest available information. We will take into account any further information available on the network tariff when making our final determination.

We have not introduced a retail tariff based on the residential network tariff variant because:

- stakeholders have not expressed an interest in the tariff and, according to EQ, customer uptake would be limited (if any).
- The *National Energy Retail Law (Queensland)*, in combination with the National Energy Retail Regulations, establishes 100 MWh as a consumption threshold for distinguishing between small and large business customers; it does not establish a consumption threshold (100 MWh or otherwise) for residential customers.[42] As such, existing regulated retail tariffs for basic meters (such as tariff 11) should continue to be available to residential customers even if their usage exceeds 100 MWh per annum.

Some stakeholders requested that the threshold applied in Queensland for distinguishing between small and large customers (>100 MWh per annum) be raised to either 160 MWh per annum[43] or 200 MWh per annum.[44] CPAQ also requested that caravan parks operating embedded networks be excluded from large customer tariffs.

However, as noted above, the threshold for determining a large customer is established in legislation (the *National Energy Retail Law (Queensland)*) and is a matter for the Queensland Government (and not a matter we can consider addressing as part of our price determination).

3.4 Other matters

3.4.1 Small customer metering costs

The delegation requires us to consider setting advanced digital metering (ADM) charges for small customers in regional Queensland by basing the charges on the cost of type 6 (standard) small customer metering services in SEQ. The delegation states that this ensures that customers, who do not have any genuine choice as to the type of meter they receive, pay the same regardless of what meter is installed at their premises.[45]

This is a new matter for us to consider. In previous years, metering charges for small customers were set separately by the Minister, following our determination of notified prices.

Setting charges in the manner specified would result in customers paying less for ADM charges than the actual charges associated with supplying the service. However, it is consistent with the Minister's covering letter to the delegation that states that it is not appropriate for some

[42] See ss. 5–6 of the *National Energy Retail Law (Queensland)*. Section 7 of the National Energy Retail Regulations establishes the upper consumption threshold at 100 MWh per annum, for determining whether business customers are small or large customers of electricity.
[43] Cotton Australia, sub. 5, p. 5.
[44] QFF, sub. 1, p. 3; Canegrowers, sub. 6, p. 1.
[45] Appendix A: Minister's delegation, terms of reference, clause 2(j).

customers to pay more because they have an ADM and that charges for small customer metering services should be based on the costs of type 6 meters.[46]

Stakeholders did not raise any concerns with this approach and supported cost-effective measures that assist users in their transition to ADM.[47]

Analysis and draft position

Having regard to relevant factors, our draft position is to use the AER-approved metering costs for type 6 small customer metering services in SEQ as the ADM charges for small customers. This approach is consistent with the UTP and ensures small customers pay the same metering charges, regardless of their geographic location. It is also consistent with the Minister's view that customers should not pay more based on the type of meter they have.

As our review timeframe does not fully align with the AER's review process, we have used draft ADM small customer charges provided by EQ (yet to be approved by the AER). If necessary, we will update these charges in our final determination (and note any changes from the draft charges we used).

The draft ADM charges for small customers are set out in Chapter 6.

3.4.2 Terms and conditions in tariff schedule

The Minister has asked us to consider the following aspects of the tariff schedule:

- network tariff requirements
- service provider discretions—retailer, distributor, metering and other service provider discretions
- voltage discounts
- threshold amounts for very large business customers.[48]

Network tariff requirements

The delegation requires us to consider making the tariff schedule as standalone as is practicable by:

- including all reasonable and practical, from a retail perspective, network tariff requirements as applicable to each retail tariff (except those subject to other consideration in the delegation)[49]
- consider maintaining the existing nomination of a primary tariff for each class of small customer to apply to a customer's electricity account in the event the customer does not nominate a primary tariff when opening an electricity account.[50]

The Minister said that 'network tariff reform should be progressed, but it should not be expected that those reforms be directly mirrored at the retail level as a matter of course'.[51] Further, 'while

[46] Appendix A: Minister's delegation, cover letter, p. 2.
[47] Cotton Australia, sub. 5, p. 5; EQ, sub. 3, p. 5.
[48] Connection asset customers (CACs) and individually calculated customers (ICCs).
[49] Appendix A: Minister's delegation, terms of reference, clause 2(p).
[50] Appendix A: Minister's delegation, terms of reference, clause 2(k).
[51] Appendix A: Minister's delegation, cover letter, p. 1.

certain terms and conditions are practical at a network level, in many cases they don't make sense in the retail context and if passed through, could have adverse impacts for customers'.[52]

While we have typically updated the tariff schedule in previous determinations, including to provide terms and conditions relating to new retail tariffs, the requirement to consider making the tariff schedule as standalone as practicable is new to this review.

There are two elements to this we must consider:

- making the tariff schedule as stand-alone as practicable
- not including network tariff requirements that are not reasonable and practical from a retail tariff perspective.

The tariff schedule includes the following provision, which acts as a 'catch-all' provision that can incorporate other distribution requirements not otherwise specified:

> 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.[53]

Removal of this provision would be a key amendment required to make the tariff schedule standalone. This means that any network tariff requirements not otherwise included in the tariff schedule will need to be included to ensure they apply at the retail level.

Given our usual approach under the N+R framework is to pass network tariffs (including requirements) through to retail tariffs, we have considered whether it is appropriate to depart from this approach based on issues identified by the Minister and stakeholders.

We asked stakeholders to assist by informing us of any network tariff requirements not currently reflected in the tariff schedule and identifying any that may not be reasonable and practical to apply at the retail level.

Stakeholder comments

EQ supported the principle of a standalone retail tariff schedule, but considered this is best achieved by removing unnecessary network tariff requirements, maintaining those where there is a legitimate need to mirror technical requirements (e.g. supply conditions for interruptible supply tariffs) and retaining the catch-all provision included in the tariff schedule (set out above).[54]

Based on subsequent information provided by EQ, it also questioned the merits of reproducing network tariff conditions in the schedule, including whether this would be in the interests of customers (given customers' preferences for simple and easy to understand tariffs) and the potential for inadvertent misalignment of tariff conditions, which can create uncertainty and confusion for all parties.

Stakeholders did not identify any specific network requirements not reflected in the current tariff schedule. Neither did they comment on any requirements that are not reasonable and practical to apply at the retail level.

[52] Appendix A: Minister's delegation, cover letter, p. 1.
[53] Queensland Government, *Gazette*, no. 72, 11 December 2020, p. 519.
[54] EQ, sub. 3, p. 5.

Analysis and draft position

Having regard to relevant factors, we consider the current retail tariff schedule is as standalone as is practicable at this time.

We understand the desire for the tariff schedule to be simpler and more accessible for customers. Stakeholders said the retail tariff schedule would benefit from more concise information (including simpler language)[55] and that it should not seek to reproduce detailed network tariff requirements.

However, the tariff schedule also needs to provide sufficient detail and information to provide certainty to stakeholders about how tariffs are to be applied and made available to customers. Ultimately, a balance needs to be struck. However, it is relevant the tariff schedule currently:

- contains key network conditions relevant to stakeholders, including details on load control network tariff requirements[56]
- contains retail-specific terms and conditions, some of which do not reflect particular network conditions. For example, the default network tariff assignment criteria are not applied at the retail level (discussed further below)
- does not appear, at least from stakeholder comments, to be deficient or lacking in key information and details relevant from a customer or retailer perspective
- contains a catch-all provision, allowing relevant current (and future) network tariff requirements to be passed through by retailers if needed.

In addition, the tariff schedule will need to include the terms and conditions for the new retail tariffs, the network tariffs for some of which are still being determined as part of the AER's annual pricing proposal process (see section 3.3). Given the timing of our price determination process, we consider it prudent to retain the catch-all provision in the tariff schedule at this time.

Accordingly, we consider the tariff schedule is as standalone as practicable at this time.

We have also maintained the approach from previous determinations and have not included default network tariff assignment requirements, including for the new retail tariffs. This means the existing default retail tariffs[57] are the only default retail tariff assignment arrangements.

Service provider discretions

The delegation requires us to consider removing retailer, distributor, metering, and other service provider discretions from the tariff schedule as far as is practicable. We have been specifically directed to consider:

- removing the existing retailer discretion that makes tariff 33 available to residential customers as a primary tariff
- setting a sunset date by which all existing residential customers accessing tariff 33 as a primary tariff must be transitioned to a suitable non-interruptible supply primary tariff.[58]

[55] Cotton Australia, sub. 5, p. 5.
[56] We note that the schedule does not completely mirror or reproduce network tariff requirements and terminology.
[57] If a small customer does not nominate a tariff when they become a standard contract customer, they will be assigned to the applicable flat-rate tariff (tariff 11 or 20), except where an existing meter configuration is for a primary load control tariff, in which case the customer must expressly nominate a suitable tariff.
[58] Appendix A: Minister's delegation, terms of reference, clause 2(i).

Analysis and draft position

We have considered whether it is practicable to remove specific service provider discretions. As a general principle, it may not be practicable to remove a discretion if it is necessary for the proper functioning of tariff arrangements.

We have also considered these discretions in light of the N+R framework (see section 3.2), which may mean that we decide to retain discretions that are reflected in network tariff requirements or exclude discretions that provide tariff options that are not reflected in network tariffs.

Tariff 33 retailer discretion

Our draft position is to remove the retailer discretion to make tariff 33 (a secondary tariff with interruptible supply—that is, a secondary load control tariff) available to residential customers as a primary tariff. The use of a load control tariff as a primary tariff is not a tariff option that is supported at the network level for residential customers. Further, the circumstances in which a retailer would approve this tariff option for residential customers is not clear—in most circumstances it would not seem appropriate to use a load control tariff as the primary electricity supply in a residential context.

We have provided a 12-month transition period for existing residential customers using this tariff option to move onto an alternative tariff. EQ supported this, noting it would enable Ergon Energy Retail to work with customers and move them to a tariff appropriate for their individual needs.[59]

Tariff 33 will continue to be available to small customers as a secondary tariff.

Cotton Australia queried whether removing this discretion for residential customers will have any impact on irrigators who have been able to access tariff 33 as a dynamic interruptible supply tariff.[60] The retailer discretion for small business customers to use tariff 33 as a primary tariff was removed as part of our supplementary price determination of October 2020[61], given that determination introduced a specific primary load control tariff for small business customers.

Other discretions

Our draft position on other service provider discretions is set out in Table 3.1.

Table 3.1 List of existing service provider discretions

Service provider discretion	***Analysis and draft position***
Connection asset customers (CACs) or individually calculated customers (ICCs) can only access tariffs where specifically stated in the tariff description, or as agreed by the retailer.[62]	EQ supported the removal of this discretion and stated its preference is for CACs and ICCs to be on tariffs which have been developed specifically for these customer types.[63] Cotton Australia said it wants to maintain an option for customers in the CAC, ICC and large categories to be able to make intra-year tariff changes allowing them to select the most suitable tariff from any tariff class, noting the seasonal variations in electricity use for cotton ginning.[64]

[59] EQ, sub. 3, p. 9.
[60] Cotton Australia, sub. 5, p. 5.
[61] QCA, *Supplementary review: regulated retail electricity prices 2020–21*, final determination, October 2020, p. 13.
[62] Queensland Government, *Gazette*, no. 72, 11 December 2020, p. 519.
[63] EQ, sub. 3, p. 6.
[64] Cotton Australia sub, pp. 5–6.

Service provider discretion	*Analysis and draft position*
	This retailer discretion enables a tariff option that does not appear to be provided for in network tariff arrangements and it is unclear about the circumstances in which a retailer would exercise this discretion. In accordance with the N+R framework, our draft position is to remove this retailer discretion. We consider customers should use the tariffs for their customer type.
The retailer, at its absolute discretion, may switch a customer to an obsolete tariff only once, if that customer: • Is participating in the Drought Relief from Electricity Charges Scheme (DRECS) on 30 June 2019 and is accessing a tariff classified as obsolete from 1 July 2019; and • Loses eligibility for DRECS before 30 June 2021; and • Nominates to return to the tariff now classified as obsolete that they were accessing immediately before their current period of participation in the DRECS.[65]	Our draft position is to remove this entire provision from the tariff schedule, given the relevant scheme is set to expire prior to the commencement of this price determination period (i.e. 2021–22).
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.[66]	Our draft position is to retain this discretion, as we consider it is necessary for the proper functioning of tariff arrangements.[67] In the absence of having this discretion, customers in these circumstances may have their electricity supply disconnected until they nominate a tariff, which we consider would not be in the interests of customers. In retaining this discretion, we note this will only apply if a customer does not nominate an alternative tariff themselves. Customers may also nominate an alternative tariff in future, if they have been transferred to a tariff by the retailer.
Where a customer's aggregate load that is connected to an interruptible supply tariff exceeds 20 amperes per phase, additional load control equipment must be installed in accordance with the QECMM. Such equipment must be installed at the customer's expense unless otherwise agreed with the metering service provider.[68]	EQ suggested this condition be retained to make explicitly clear that the customer is responsible for this cost so there is no customer confusion or distress, although it did not comment specifically on the discretion.[69] We are considering whether to remove the discretion for the metering service provider to agree to bear the costs for this equipment, rather than the entire condition. Subject to stakeholder submissions, our draft position is to remove this discretion. Whether or not a metering service provider agrees to bear this cost for a customer appears to be a

[65] Queensland Government, *Gazette*, no. 72, 11 December 2020, p. 519.
[66] Queensland Government, *Gazette*, no. 72, 11 December 2020, p. 520.
[67] While this discretion has been retained in the draft tariff schedule, it has been relocated due to other amendments made to the tariff schedule–see Appendix I.
[68] Queensland Government, *Gazette*, no. 72, 11 December 2020, p. 520.
[69] EQ, sub. 3, p. 7.

Service provider discretion	***Analysis and draft position***
	matter between those parties and it is unclear that this discretion is necessary in the retail tariff schedule.
Tariff 31 … 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.[70]	EQ suggested retaining these conditions to make it explicitly clear to customers that timeframes of supply will vary subject to the distribution entity's discretion.[71] Our draft position is to retain these discretions. We consider it is not practicable to remove the discretion of a distribution entity to interrupt supply under these tariffs, given the premise of load control tariffs and the fact these discretions are reflected in the underlying network tariffs.
Tariff 33 … Times when supply is available is subject to variation at the absolute discretion of the distribution entity.[72]	
Tariffs 34, 60A and 60B Times when supply is available is subject to variation at the absolute discretion of the distribution entity.[73]	
Tariffs 31, 33 and 60B These tariffs are applicable where there is no provision to supply approved apparatus, or any specified part of an approved apparatus connected to an interruptible supply tariff, via another tariff (e.g. via a change-over switch to a primary tariff), except as agreed by the retailer, and electricity supply is: • connected to approved apparatus (limited to electric vehicle supply equipment (residential customers only), and pool filtration systems) via a socket-outlet as approved by the retailer; or • permanently connected to approved apparatus (e.g. electric hot water system, battery energy storage system, solar power system), or approved specified parts of apparatus (e.g. hot water system booster heating unit) as approved by the retailer. Where the retailer has approved the connection of a specified part of apparatus to another tariff (e.g. for a one-shot booster for a solar hot water system), the specified part 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.[74]	EQ suggested retaining this condition.[75] Our draft position is to remove the discretion for the retailer to agree to an exception to these arrangements, as it is not reflected in the network tariff requirements. We have also proposed changes to the eligibility criteria for these tariffs which aligns better with network tariff requirements. We consider this to be appropriate to improve clarity and the stand-alone nature of the tariff schedule.
Tariff 91 It is available only to customers with small loads other than streetlights as approved by the retailer, and applies where:	EQ suggested that this condition should be retained. It said the unmetered supply network tariff will be determined at the time of connection by the distribution entity.[77]

[70] Queensland Government, *Gazette*, no. 72, 11 December 2020, pp. 520–521.
[71] EQ, sub. 3, p. 8.
[72] Queensland Government, *Gazette*, no. 72, 11 December 2020, p. 521.
[73] Queensland Government, *Gazette*, no. 72, 11 December 2020, p. 521.
[74] Queensland Government, *Gazette*, no. 72, 11 December 2020, p. 521.
[75] EQ, sub. 3, p. 9.
[77] EQ, sub. 3, p. 10.

Service provider discretion	Analysis and draft position
(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.[76]	This discretion is for the retailer to approve small loads (other than streetlights) for this tariff. We understand the distribution entity has a role in approving these types of connections. Our draft position is to replace the retailer's discretion by instead referring to the distribution entity's approved unmetered supply devices list (or equivalent document).[78] However, we seek comments from stakeholders, including retailers, on this approach.
Tariff changes 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.[79]	EQ supported removal of this condition.[80] Cotton Australia considered there should be an option for customers in the CAC, ICC and large customer categories to be able to make intra-year tariff changes allowing them to select the most suitable tariff from any tariff class.[81] CPAQ also considered that customers should be able to change their tariffs as frequently as every three months, noting that caravan parks generally have significant variation in their energy usage between seasons.[82] Our draft position is to remove the discretion for the retailer to agree to allow customers on seasonal time-of-use tariffs to change to another tariff less than one year from the application of the tariff to the customer's account. It is unclear on what basis the retailer would exercise this discretion, given the nature and design of seasonal tariffs.
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.[83]	EQ supported removal of this condition as it considered this was no longer an issue given the standard asset customer (SAC)/CAC/ICC designations.[84] Our draft position is to remove this retailer discretion so that voltage supply must be as per the tariff description. This is consistent with our draft position to remove the retailer discretion to allow CACs or ICCs to access tariffs not designated for use by CACs or ICCs.
Meter wiring and equipment to house meters is the customer's responsibility and must be installed and	EQ supported removal of this tariff condition, although it did not specifically comment on the discretion.[86]

[76] Queensland Government, *Gazette*, no. 72, 11 December 2020, p. 521.
[78] For example, see Ergon Energy Network, *Approved unmetered supply devices*, December 2017.
[79] Queensland Government, *Gazette*, no. 72, 11 December 2020, p. 522.
[80] EQ, sub. 3, p. 10.
[81] Cotton Australia, sub. 5, pp. 5–6.
[82] CPAQ, sub. 2, p. 5.
[83] Queensland Government, *Gazette*, no. 72, 11 December 2020, p. 522.
[84] EQ, sub. 3, p. 10.
[86] EQ, sub. 3, p. 11.

Service provider discretion	***Analysis and draft position***
maintained at the customer's expense unless otherwise agreed with the metering service provider.[85]	We are considering whether to remove the discretion for the metering service provider to agree to bear the costs for this equipment, rather than the entire condition. Subject to stakeholder submissions, our draft position is to remove this discretion. Whether or not a metering service provider agrees to bear this cost for a customer appears to be a matter between those parties and it is unclear that this discretion is necessary in the retail tariff schedule.
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.[87]	EQ supported removal of this tariff condition, although said that it would investigate the service provider discretions more closely and would report if issues arise if service provider discretions are removed. EQ subsequently advised us it recommends that all discretions relating to card operated meters should be retained.[88] We understand EQ is the only party that is permitted to provide card operated meters in Queensland. We recognise these are unique arrangements and it may be practicable to retain discretions for this matter. Our draft position is to maintain the existing discretions. However, we seek stakeholder comments on whether it is necessary for the distribution entity to be part of the decision or whether it would be sufficient for the local government authority (on behalf of the customer) and the customer's retailer to agree with the usage of a card operated meter.

Voltage discounts

The delegation requires us to consider the ongoing appropriateness of the discounts applied where supply is given and metered at high voltage, and the tariff applied is not a designated high voltage tariff. Specifically, the tariff schedule includes the following provision:

> 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.[89]

[85] Queensland Government, *Gazette*, no. 72, 11 December 2020, p. 522.
[87] Queensland Government, *Gazette*, no. 72, 11 December 2020, p. 522.
[88] EQ, sub. 3, pp. 6, 11.
[89] Queensland Government, *Gazette*, no. 72, 11 December 2020, p. 522.

Stakeholder comments

EQ said it supports the removal of the voltage discount provisions from the tariff schedule, because:

- the high voltage discounts have been replaced by customers moving to the ICC and CAC tariffs
- the distributor removed the SAC high voltage network tariffs several years ago, meaning that at the SAC level they do not provide discounts based on connection arrangements
- ICC and CAC retail tariffs do not attract high voltage rebates.[90]

Based on subsequent information provided by EQ, we understand that these rebates are a legacy arrangement and were originally used to compensate customers for supplying and maintaining equipment. Further, EQ noted that in our 2012–13 determination we removed an additional high voltage discount associated with transmission connection point costs on the basis that Powerlink did not discount its transmission charges to Ergon Distribution, which were then charged to retailers. EQ said it is unclear why these other high voltage rebates were not removed at that time as the same rationale (no explicit discounts at the distribution level) applies.

Analysis and draft position

On the available information, it appears that high voltage rebates are a legacy arrangement that is no longer reflected at the distribution level and may not have been for some time.

However, it is unclear how many customers are currently receiving the rebate (and are expected to receive it in the coming year), although we understand from EQ the number of customers is likely to decrease as customers move from obsolete tariffs to ICC and CAC standard retail tariffs (which would not attract the rebate).

While EQ supported removing this rebate provision, customers have not commented on this matter.

Given the uncertainty on the extent of customers impacted, we seek further information from retailers and customers about how the rebate is currently applied to customers, including customers that are not on obsolete tariffs and that would be affected by the removal of the rebate.

Threshold amounts used in CAC and ICC definitions

The delegation requires us to consider updating the threshold amounts used in the tariff schedule definitions for CACs and ICCs to generally reflect the equivalent network tariff thresholds.

The tariff schedule includes the following definitions:

- A CAC is a large business customer whose required capacity generally exceeds 1500 kVA and annual energy usage generally exceeds 4 GWh as classified by the distribution entity.
- An ICC is a large business customer whose annual energy usage generally exceeds 40 GWh as classified by the distribution entity.[91]

These are different from the definitions for network tariffs, in particular with respect to the customer thresholds:

[90] EQ, sub. 3, p. 11.
[91] Queensland Government, *Gazette*, no. 72, 11 December 2020, p. 519.

- For the CAC network tariff class description, there is an installed capacity threshold of above 1,000 kVA, and the network tariff definition does not include an annual energy usage threshold.
- For the ICC network tariff class description, there is an installed capacity threshold of above 10 MVA, and the network tariff definition does not include an annual energy usage threshold. The ICC tariff class description also includes a set of circumstances in which customers with installed capacity below 10 MVA may also be allocated to the ICC tariff class.[92]

Analysis and draft position

We consider it appropriate that any updates to definitions (or changes identified) at a network level be reflected at the retail level, including to update threshold amounts in definitions as described. This ensures consistency and, as noted by EQ[93], reduces the potential for confusion.

As such, we have updated the tariff schedule to reflect network tariff thresholds. That is:

- for the CAC network tariff class description, there is an installed capacity threshold of above 1,000 kVA, and the customer is connected to the distribution network at a minimum nominal voltage of 11 kV, but not exceeding a nominal voltage of 66 kV as classified by the distribution entity
- for the ICC network tariff class description, there is an installed capacity threshold of above 10 MVA, and the customer is connected to the distribution network at a minimum nominal voltage of 33 kV, but not exceeding a nominal voltage of 132 kV as classified by the distribution entity.[94] A customer taking supply at these voltages, but with installed capacity less than 10 MVA, may request to be classified as an ICC if they satisfy specific criteria set out in the distribution entity's approved TSS.

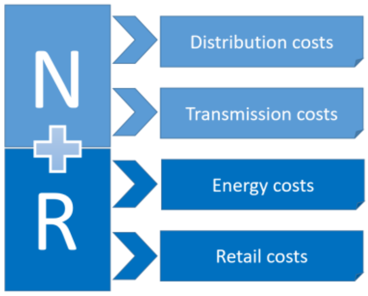
[92] See Ergon Energy, *Ergon Energy Tariff Structure Statement 2020–25*, June 2020 (Erratum: version 6, August 2020, p. 16).
[93] EQ, sub. 3, p. 11.

4 INDIVIDUAL COST COMPONENTS

This chapter provides our draft position on issues related to the cost build-up components under the N+R approach we use to set notified prices.

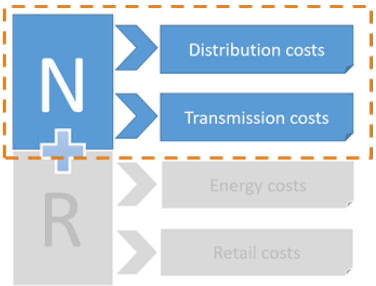
Many of these issues are in the delegation (and terms of reference), which we must consider when setting notified prices. For instance, the Minister has provided specific matters for us to consider in determining the network component (for the new retail tariffs) and the retail component (updating the retail operating costs included in notified prices).

The cost components discussed are:



- the network (N) component—the distribution and transmission costs associated with transporting electricity to customers (section 4.1)
- the retail (R) component—the costs of buying and selling electricity to customers (section 4.2).

4.1 Network component



Network costs comprise the costs of transporting electricity through transmission and distribution networks, as well as jurisdictional scheme charges,[95] all of which are regulated (and approved) by the AER.

Overall, network costs this year (depending on the tariff) are expected to:

- increase by 0.5 to 1.3 per cent for small customers
- decrease by 0.8 to 2.2 per cent for large customers.

4.1.1 Matters in the delegation

The delegation requires us to consider determining the N component in a manner that reflects overarching framework matters—that is, the UTP and N+R methodology (discussed in section 3.2). We must base the N component as follows:

- for residential and small business customers on:
  - flat and secondary load control tariffs—on the relevant Energex network prices (being the charges and tariff structures levied by Energex that apply in SEQ)
  - tariffs 12A, 14, 22A and 24—on the N component used in the 2020–21 price determination, adjusted using a price indexation methodology (on the basis these tariffs no longer have an underlying network tariff)
  - all other tariffs—on the price level of the relevant Energex charges but utilising Ergon Distribution tariff structures

[95] In Queensland, these charges generally include the Solar Bonus Scheme (SBS) and AEMC levy costs.

- for large customer retail tariffs—on the relevant network prices for Ergon Distribution's east zone, transmission region one.[96]

The delegation also sets out specific matters for determining the N component of new retail tariffs (see section 3.3). We must base the N component as follows:

- for the three new transitional retail tariffs—on the relevant network prices for Ergon Distribution's east zone, transmission region one
- for the new large customer retail tariff based on the 'Business customer (Basic)>100 MWh pa' network tariff—on the relevant network prices for Ergon Distribution's east zone, transmission region one
- pending the need for it, for the new residential retail tariff based on the 'Residential customer (Basic)>100 MWh pa'[97] network tariff—on the price level of the relevant Energex charges but utilising Ergon Distribution tariff structures.

The delegation is broadly consistent with previous years and the way in which we have set the N component of notified prices in previous price determinations. There are some new considerations relating to the new retail tariffs.

4.1.2 Stakeholder comments

Stakeholders focused on the possible complications in determining the N component:

- Canegrowers said that the relevant final decisions from the AER may not be available at the time of the final price determination[98]
- EQ stated that where there is no underlying network tariff, indexation can be used in the interim but closing the tariffs may be appropriate in the longer term.[99]

4.1.3 Analysis and draft position

We have determined the N component for existing tariffs (for both small and large customers) and new tariffs having regard to the relevant factors, stakeholder comments and our own analysis. We have set the N component:

- for existing retail tariffs with an underlying network tariff, by passing through the relevant network prices approved by the AER. Consistent with the UTP, this means:
  - for small customers, basing costs on the costs of supply in SEQ (Energex distribution)
  - for large customers, basing the costs of supply on east zone, transmission region one (Ergon Distribution's lowest-cost region that is connected to the NEM)

[96] The Ergon Distribution pricing region with the lowest cost of supply that is connected to the NEM.
[97] As discussed in section 2.2.2, we have been directed by the Minister to consider introducing this residential tariff variant only if it would satisfy a need for the tariff at the retail level.
[98] Canegrowers, sub. 6, attachment p. 2.
[99] EQ, sub. 3, p. 12.

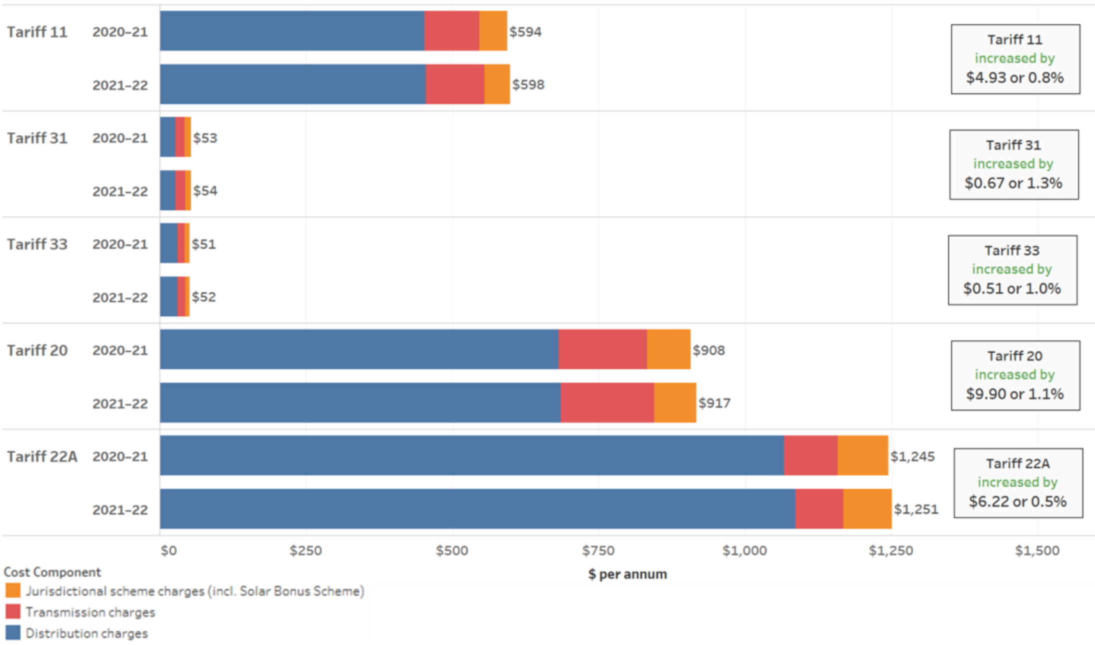
- for retail tariffs with no underlying network tariff (tariffs 12A, 14, 22A and 24), using a price indexation methodology, specifically an 'X-factor' approach[100], which will allow for the pass-through of AER-approved changes in network costs to customers on these retail tariffs[101]
- for the new transitional retail tariffs and the new large customer business tariff, by passing through the relevant network prices approved by the AER. This means basing the costs on the cost of supply in east zone, transmission region one (Ergon Distribution's lowest- cost region that is connected to the NEM).

The N component for the new residential tariff is not discussed, given this tariff is not being introduced in this price review (see section 3.3).

Setting the N component as described above is consistent with our broader pricing approach (see section 3.2) and the approach we have applied in previous price determinations, as well as the specific cost considerations for new retail tariffs (discussed in section 3.3).

Overall, this year the network costs included in the draft notified prices have increased for small customers and decreased for large customers (see charts below).

Figure 3.1 Draft network costs—typical customers on small customer tariffs (GST incl.)

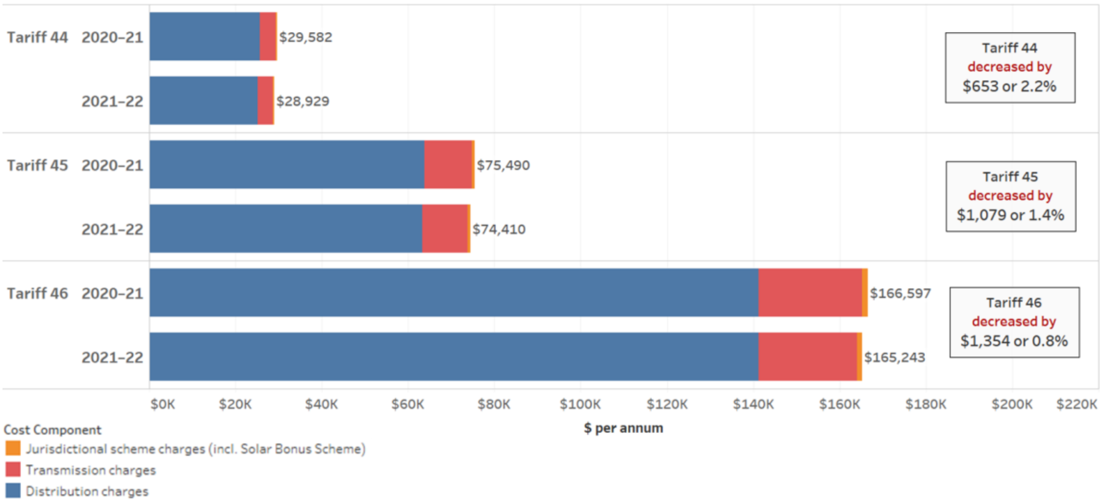


Note: Amounts are rounded to the closest dollar. Therefore, amounts may not add precisely. Percentage changes are based on unrounded amounts.

[100] As part of the revenue determination process, the AER produces five X-factors for the purposes of revenue smoothing (the X-factor for the first year is also known as P_0). Mathematically, X-factors are weights that are applied to allowable revenue for one year to calculate the allowable revenue for the next year using a price formula of the form—(CPI–X).

[101] Specifically, we propose to use the N component that was set for these tariffs as part of our 2020–21 determination as the starting point, which will then be indexed by using the relevant AER X-factors and the *CPI minus X* price formula. For further details on how we set the N component for these tariffs, see Appendix C of our 2020–21 price determination.

Figure 4.2 Draft network costs—typical customers on large customer tariffs (GST incl.)



Note: Amounts are rounded to the closest dollar. Therefore, amounts may not add precisely. Percentage changes are based on unrounded amounts.

We discuss access to tariffs, including those mentioned by EQ, as part of the broader framework matters (chapter 3). However, we note that using the price indexation approach enables us to set notified prices for retail tariffs that no longer have underlying network tariffs to base network costs on. This allows us to maintain (and allows customers to continue to access) the suite of existing retail tariffs, including the less common small customer retail tariffs, as we have been asked to do under the delegation.

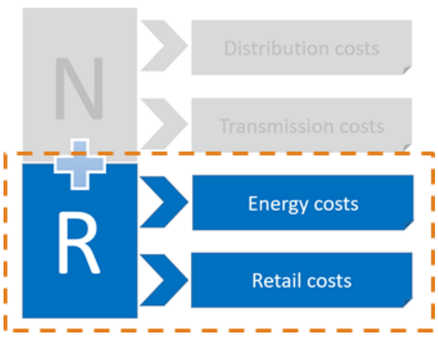
Timing

Due to our review timeframes, we used draft network prices provided to us by Ergon Distribution and Energex as the relevant network prices. We intend to use the updated pricing approved by the AER in its 2021–22 network determinations in our final determination, pending the availability and timing of this information.

We note stakeholders concerns regarding the timing of the AER's final network determinations. If at the time of our final determination the AER is yet to publish the approved network prices, we propose to use the same approach we applied in the previous price determination. That is, using the 2021–22 pricing proposals submitted to the AER by Ergon Distribution and Energex. If the AER's approved prices differ from those submitted by Ergon Distribution and Energex, we will consider using a cost pass-through mechanism to adjust for material differences, if we are delegated this task in the future.

4.2 Retail component

The R component consists of energy and retail costs. These include the costs retailers incur when they purchase electricity to supply their customers, the costs of running their general operations, and a return for the risk they face by operating in the market.



We propose to use broadly the same approach to determine energy costs as we adopted last year. Total energy costs are expected to decrease by 14.9 per cent to 17.3 per cent for small customers (depending on the tariff) and by 13.9 per cent for large customers.

We propose to update the retail cost allowances to serve small customers to account for recent market information but to use the existing retail cost allowance for large and very large customers, adjusted by inflation.

Overall, total retail costs are expected to decrease by 21.9 per cent to 43.1 per cent for residential customers, increase by 9.9 per cent to 14.1 per cent for small business customers, and decrease by 4.3 per cent to 6.1 per cent for large customers, depending on the tariff.

4.2.1 Energy costs

Energy costs include costs associated with wholesale energy costs (the costs of purchasing electricity from the NEM), other energy costs and energy losses.

Consistent with previous years, we have engaged ACIL Allen to provide expert advice on energy costs.[102] Our draft position for this review is to estimate energy costs based on ACIL Allen's advice.

Stakeholder submissions

Stakeholders broadly supported us applying the same approach to estimate energy costs that we used in previous years. EQ also suggested that we should:

- consider modifying the spot price simulation methodology, including adjusting the frequency of negative spot prices in the simulation to reflect the more frequent occurrence of negative prices to date
- investigate the effects of the AEMC's five-minute settlement reform and its impact on the availability of ASX cap contracts and the hedging strategy
- examine the hedging strategy used by ACIL Allen to estimate wholesale energy costs and ensure that it is not applied on an ex post basis[103]
- take into account the impacts of covid-19.[104]

Canegrowers suggested that a separate wholesale energy cost should be estimated for irrigation activities to reflect the relevant network tariff structures.[105]

Wholesale energy costs

Retailers incur wholesale energy costs when purchasing electricity from the NEM to meet the electricity demand of their customers. Retailers typically adopt a range of strategies to reduce their exposure to volatile wholesale electricity prices (spot price risk) when purchasing from the NEM, including pursuing hedging, contractual and operational strategies.

We propose to determine wholesale energy costs based on the ACIL Allen estimates, which reflect:

- a market hedging approach—to simulate expected spot prices that a retailer faces (having regard to the likely variation in demand profiles and generation and supply costs), and then

[102] ACIL Allen, *Estimated Energy Costs*, draft report prepared for the QCA, March 2021.
[103] This refers to the practice of deriving a hedging strategy after the simulated spot prices are known.
[104] EQ, sub. 3, pp. 12–13.
[105] Canegrowers, sub. 6, p. 2.

estimate wholesale energy costs for a retailer that hedges spot price risk (through exchange-traded energy derivatives, i.e. ASX energy futures[106])

- market data up until February 2021—to take into account the most current information (including developments over the potentially volatile summer period).[107]

This is broadly similar to the approach applied in previous years.

Analysis and draft position

Our draft position is to determine wholesale energy costs based on ACIL Allen's advice, using a market hedging approach. We consider this approach:

- is likely to produce reliable estimates that best reflect the costs retailers incur (when purchasing electricity from the NEM) by using the most up-to-date market data and publicly available ASX contract data
- adequately addresses the issues raised in stakeholder submissions.

This approach uses the latest available market data—including information on the uptake of rooftop solar PV, renewable energy resource traces[108], the latest peak demand and supply projections of the Australian Energy Market Operator (AEMO), and market participants' formal announcements on generation availability/operation. This means our estimates adequately take into account the likely variation in demand profiles and generation supply/costs (including fuel costs) within the NEM, while still meeting our draft determination timeframe.

Importantly, a market-based approach has the advantage of being more transparent than other methodologies (such as the long-run marginal cost approach), as it makes use of financial derivative data (i.e. ASX contract data) that are readily available in the public domain.[109]

We have considered the points stakeholders raised and a summary of our assessment is outlined below. More details are available in Appendix C.

We examined EQ's proposed changes in relation to the spot price simulation methodology but are not in favour of undertaking an ex post adjustment for this approach, as:

- the methodology reflects the best information available at the time when the projected spot prices were developed
- the factors leading to lower than expected spot prices and higher frequency of negative spot prices are likely due to factors specific to 2020–21.

We have investigated the points that EQ raised on the effects of the AEMC's five-minute settlement reform, including whether retailers are relying on other types of financial derivatives to compensate for the lack of ASX cap contracts due to the AEMC's reform. At this stage, there is

[106] 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.
[107] See Appendix C for a detailed description of ACIL Allen's market hedging approach.
[108] Renewable energy resource traces reflect the availability and quality of renewable resources/generation in different regions, depending on weather and geographical conditions.
[109] The appropriateness of a market hedging approach is discussed further in Appendix C and ACIL Allen's draft report.

no evidence to suggest that retailers are relying on other types of financial instruments (including base and super peak contracts[110]) as a replacement for the cap contracts.

Further, ASX Energy will introduce new cap contracts[111] (designed for a five-minute settlement) to replace the existing cap contracts around mid- to late March 2021. We will investigate using the data from the newly listed cap contracts for the final determination once these contracts are sufficiently traded. In the interim, we consider ACIL Allen's approach of using historical price movements to estimate cap contract prices beyond the September 2021 quarter[112] to be pragmatic and appropriate.

In relation to EQ's comments on the hedging strategy, we confirm ACIL Allen has used the same hedging approach as in previous years and has not applied the hedging strategy on an ex post basis. Once an appropriate hedging strategy has been developed, the same strategy (i.e. the same hourly hedge volumes) was applied to all simulated demand profiles. This means that ACIL Allen does not alter the hedge volumes on an ex post basis for each of the demand profiles.

EQ raised the topic of the impacts of covid-19. We consider that this approach adequately takes into account the potential impacts of covid-19 on the NEM, including through the incorporation of ASX contract data until February 2021. These contract prices reflect market participants' views to date of the impacts of covid-19, as well as other drivers, on the NEM. We have also used AEMO's latest demand forecasts, which include the projected impacts of covid-19[113], to estimate wholesale energy costs. For the final determination, we will use contract data until April 2021 to estimate wholesale energy costs.

We have examined Canegrowers' suggestion that a separate wholesale energy cost should be estimated for irrigation activities to reflect the relevant network tariff structures. We note that, at this stage, most small business customers in Queensland, including irrigators, are on accumulation meters. To allow for retailers to purchase electricity from the NEM for customers on accumulation meters, AEMO has developed and utilised the net system load profiles (NSLPs). As a result, the cost to a retailer purchasing electricity to supply an irrigator with an accumulation meter is based on the NSLPs. On this basis, we consider it appropriate to continue with the existing approach of estimating wholesale energy costs for irrigators based on the NSLPs.

Compared to the estimates from last year, our draft estimates of wholesale energy costs have fallen for both small and large customer tariff classes[114]—reflecting the expected continued entry of a large amount of renewable generation into Queensland and other NEM regions and the continuation of lower domestic gas prices.[115]

[110] A super peak contract is designed to cover demand in the early morning and evening peak periods (i.e. outside of the main periods in which rooftop solar PV produces electricity).

[111] The new cap contract will be known as the Australian Base Load 5 Minute Cap Futures Contract.

[112] ACIL Allen has estimated the cap contract prices beyond the September 2021 quarter by using the percentage price movement in the September quarter cap contracts between 2020–21 and 2021–22.

[113] AEMO, *2020 Electricity Statement of Opportunities*, August 2020.

[114] As discussed in Chapter 3, our draft position is to base notified prices for small customers on the costs of supply in SEQ, and for large customers on the costs of supply in Ergon east zone, transmission region one. This means the wholesale energy costs for small and large customers are based on the Energex and Ergon profiles respectively.

[115] The lower domestic gas price is the result of improved supply performance of coal seam gas (CSG) fields in Queensland, decreased demand from gas-fired generation and a decline in international liquefied natural gas (LNG) export prices, among other factors.

Other energy costs and losses

Retailers incur other energy costs[116] and losses when purchasing electricity from the NEM, namely:

- Renewable Energy Target (RET) costs—costs associated with the purchase of certificates to meet the targets mandated under the RET[117]
- NEM management fees and ancillary services charges—the costs levied by the AEMO to cover the cost of operating the NEM and services used to manage power system safety, security and reliability
- Reliability and Emergency Reserve Trader (RERT) scheme charges—charges levied by AEMO to cover the costs of maintaining power system reliability and security using reserve contracts. The RERT scheme allows AEMO to contract for emergency reserves, such as generation or demand response outside of the NEM
- prudential capital costs—the costs a retailer incurs to provide financial guarantees to AEMO and to lodge initial margins with the ASX for futures contracts
- costs associated with energy losses—this is because retailers need to purchase more electricity than is demanded by customers to allow for losses that occur when electricity is transported (via transmission and distribution networks).

[116] Retailers may also incur costs related to the Retailer Reliability Obligation (RRO). The RRO is designed to assist with managing the risk of declining reliability of generation supply. When the RRO is triggered for a given quarter and NEM region, retailers are required to secure sufficient qualifying contracts to cover their share of the peak demand. At this stage, for 2021–22, the RRO has not been trigged for Queensland and therefore no RRO costs have been incurred. For a more detailed explanation of our considerations and ACIL Allen's approach, refer to Appendix C and ACIL Allen's draft report.

[117] The RET, comprising 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.

Analysis and draft position

Our draft position is to determine other energy costs and losses based on ACIL Allen's advice:

RET costs	•Large-scale Renewable Energy Target (LRET) costs—estimated using forward prices for large-scale generation certificates (LGC) and renewable power percentage (RPP) values derived from mandated LRET targets and estimates of electricity acquisitions •Small-scale Renewable Energy Scheme (SRES) costs—estimated using the clearing house price for small-scale technology certificates (STC) and small-scale technology percentages (STP) that reflect the most recent expected uptake in small-scale renewable energy systems
NEM fees and ancillary charges	•NEM management fees—estimated using AEMO's budget and fee projections •Ancillary services charges—estimated using the average historical costs observed over the preceding 52 weeks
Prudential costs	•Prudential costs—estimated using AEMO's prudential requirements and margin requirements for trading in the ASX futures market
RERT scheme charges	•RERT scheme charges—estimated using the historical costs published by AEMO for the preceding 52 weeks
Energy losses	•Energy losses—estimated by applying transmission and distribution loss factors published by AEMO, in a manner that aligns with AEMO's settlement process

We consider that these approaches are appropriate and are likely to produce reliable estimates of other energy costs incurred by retailers. These methodologies are aligned with the way retailers incur these costs in practice, and use the latest market data, where available and appropriate, to enhance the accuracy of the estimates.[118]

Compared to the estimates from last year:

- LRET costs have decreased by approximately 17 per cent ($0.86/MWh)—driven by a fall in the forward price of large-scale generation certificates due to an increase in renewable investment
- SRES costs have increased by about 3 per cent ($0.27/MWh)—driven by an increase in the number of small-scale technology certificates retailers are required to purchase, due to a higher uptake in small-scale renewable energy systems than previously estimated
- NEM management fees have declined by around 31 per cent ($0.22/MWh)—reflecting a decline in costs related to operating the NEM and the exclusion of costs associated with AEMO's function as the National Transmission Planner

[118] The appropriateness of these approaches is discussed further in Appendix C and ACIL Allen's draft report.

- ancillary services charges have decreased by approximately 71 per cent ($1.08/MWh)—due to the additional generation supply (that can offer ancillary services) being commissioned to this relatively small market
- prudential costs have decreased by around 4 per cent ($0.07/MWh) for small customer tariffs and by about 4 per cent ($0.06/MWh) for large customer tariffs—reflecting lower contract prices and lower expected price volatility in the NEM.

In summary, compared to the estimates from last year, our draft estimate of other energy costs:

- for small customer retail tariffs decreased by 10.7 per cent ($1.96/MWh)
- for large customer retail tariffs decreased by 10.9 per cent ($1.95/MWh).

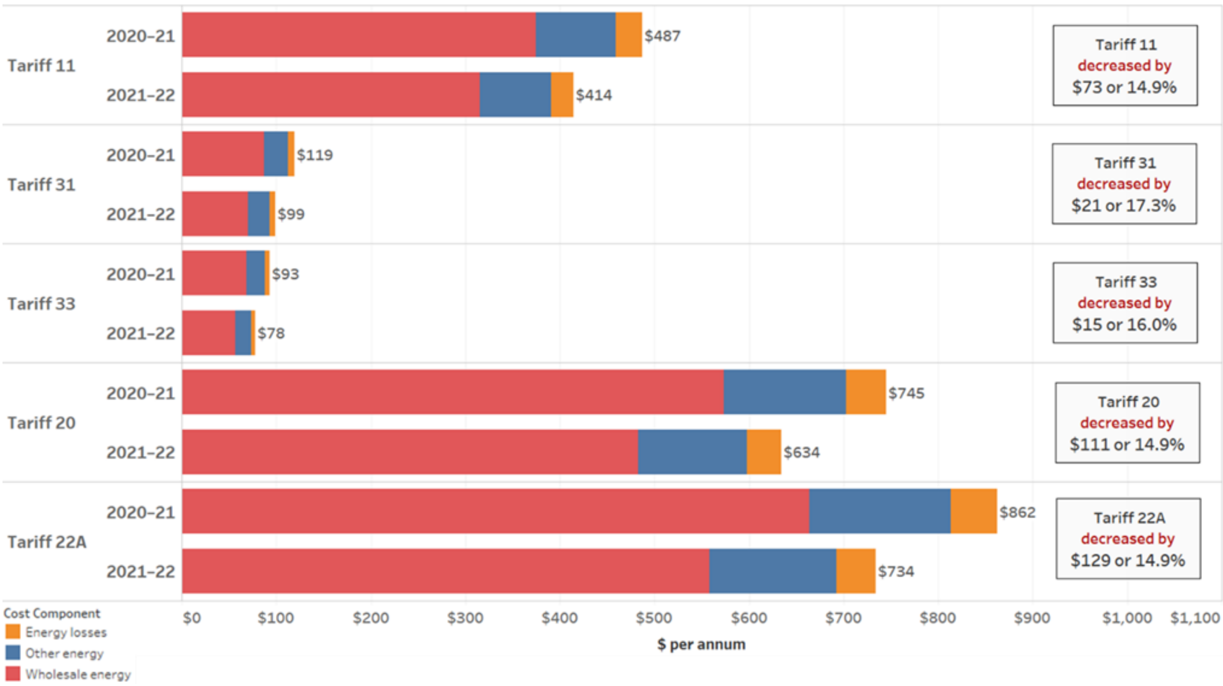
For a more detailed explanation of our considerations and ACIL Allen's approach, refer to Appendix C and ACIL Allen's draft report.

We note that the energy losses in ACIL Allen's draft report are based on AEMO's 2020–21 published loss factors, as loss factors for 2021–22 have not yet been published. ACIL Allen will update the loss factors using AEMO's 2021–22 loss factors in its final report.

Total energy costs included in draft notified prices

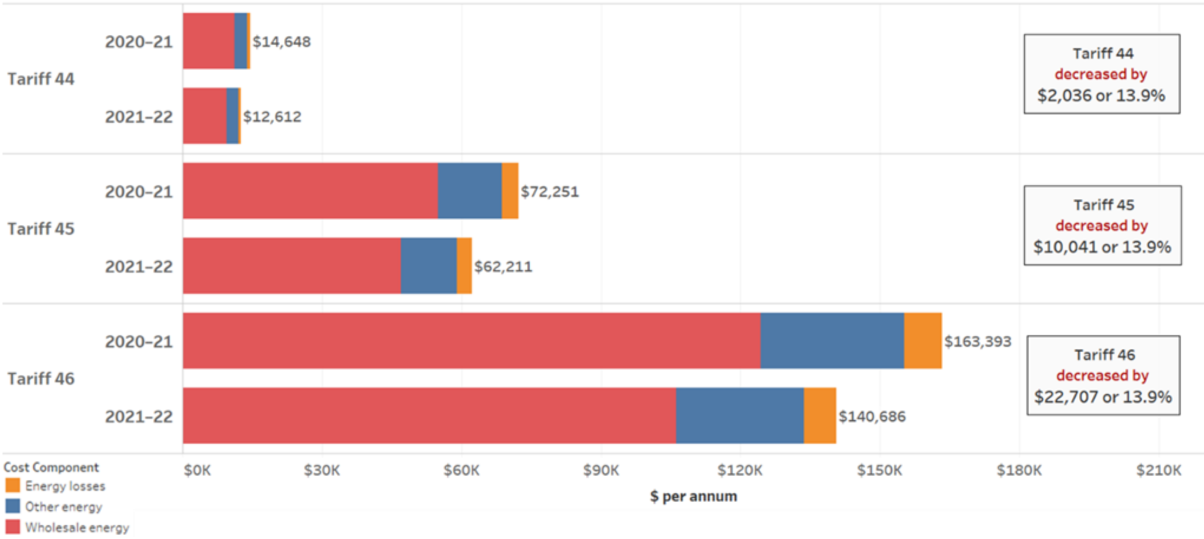
The following charts show the overall energy costs included in draft notified prices—compared to last year's estimates—by tariff type for the typical small and large customers.

Figure 4.3 Draft energy costs—typical customers on small customer tariffs (GST incl.)



Note: Amounts are rounded to the closest dollar. Therefore, amounts may not add precisely. Percentage changes are based on unrounded amounts.

Figure 4.4 Draft energy costs—typical customers on large customer tariffs (GST incl.)



Note: Amounts are rounded to the closest dollar. Therefore, amounts may not add precisely. Percentage changes are based on unrounded amounts.

4.2.2 Retail costs

Retail costs are the costs of running a retail business. They include:

- retail operating costs, such as administrative costs and costs related to operating call centres, operating billing systems and collecting revenue
- a retail margin, which is the return to investors for retailers' exposure to systematic risks associated with providing retail electricity services.

The terms of the delegation require us to consider determining the R component by undertaking a review of retail operating costs, but otherwise do not specify a particular approach or methodology for setting the retail cost allowance. We intend to undertake a more fulsome review of all retail costs, which include the retail operating costs and retail margin, as part of this price determination.[119]

In previous price determinations, we set the retail cost allowance using an established benchmark (set as part of the 2016–17 price determination process), adjusted for inflation.[120] During previous notified price reviews, stakeholders expressed a desire for retail costs to be reviewed and updated estimates to be used to set notified prices.

This year, we are proposing to update the retail cost allowances using a benchmark approach, similar to the approach used to establish retail cost allowances for 2016–17. We engaged ACIL Allen to help us determine the retail cost component of notified prices for this review, including the method and approach to update the existing retail cost benchmark allowances.

[119] Since the 2016–17 determination, the retail margin has not been separately identified due to the benchmarking approach adopted. For further detail, refer to Appendix D.
[120] This approach has been used since the 2017–18 price determinations.

Given the tight review timeframes, we asked ACIL Allen to prepare a report on the potential methodology for updating the retail cost allowances, which we released at the same time as the ICP for stakeholders to comment on.[121]

Stakeholder submissions

There was broad support from stakeholders for retail cost estimates to be reviewed, but stakeholder views differed on the appropriate methodology to use for determining this component.

Canegrowers said the proposed methodology for estimating the retail component needed to be modified to avoid inclusion of non-existent costs such as competition costs and any excess retailer margins arising from the continuing exercise of retail market power.[122]

On the other hand, EQ considered that the pricing strategies of new entrants who are establishing market share and established retailers who respond by artificially lowering their prices to protect their market share means that under the proposed approach, the retail costs would be artificially lowered well beyond their real value.[123]

EQ also said we should allow for the recovery of compliance costs associated with various regulatory and policy reforms. It commented that the use of 2020–21 data was of a significant concern, given that covid-19 and government stimulus packages have skewed certain customer metrics that are key inputs in setting retail costs.[124]

Regarding the retail cost allowances for large customers, EQ highlighted that Ergon Energy Retail needed to forecast much of the data for the 2020–21 financial year (which was provided to us), introducing additional risk to the large customer retail cost calculation.[125]

Analysis and draft position

We consider there is merit in reviewing the retail cost allowances and, where appropriate, updating them to reflect recent market information. Having regard to stakeholder comments, ACIL Allen's reports and our own analysis, we propose to:

- update the retail cost allowances for residential and small business customers (small customers) to take account of recent market information
- use the existing retail cost allowance for large and very large customers, adjusted by inflation.

Small customers

As a result of our review, we propose to update the retail cost allowances for small customers based on the outcomes of ACIL Allen's benchmarking analysis. We are of the view that it is appropriate to undertake a benchmarking exercise similar to the approach used to establish retail cost allowances for small customers for 2016–17. We consider this is a robust and transparent approach, as it relies heavily on outcomes observed in competitive retail markets.

[121] ACIL Allen, *Updating retail costs for the 2021–22 regulated electricity price review – methodology document*, report for the QCA, 2020.
[122] Canegrowers, sub. 6, p. 2.
[123] EQ, sub. 3, pp. 13–14.
[124] EQ, sub. 3, pp. 14–15.
[125] EQ, sub. 3, p. 14.

To update retail cost estimates for small customers, ACIL Allen used retail market tariffs that were offered for 2020–21 in SEQ. Retail cost estimates for small customers were updated by deconstructing the components (network, energy and other costs) of the relevant flat-rate offers to then benchmark the retail cost component. ACIL Allen's approach is explained in further detail in its methodology paper and draft report[126], which are available on our website.

Use of market data

Under the UTP, we must consider setting notified prices for small customers in regional Queensland based on the costs to supply small customers in SEQ (discussed in Chapter 2). Given this, the draft retail cost estimates for 2021–22 are based on the retail market offers in SEQ. This market is likely to be effectively competitive as suggested by the number of retailers in SEQ, the number of market offers available and the distribution of retail costs.[127] We also note that SEQ has the highest level of satisfaction with competition in Australia.[128]

Consistent with our previous practice, we do not consider it appropriate to remove competition-related costs from the estimates used to calculate the retail cost allowances. While Canegrowers said that competition related costs should be excluded from the estimates of the retail component, removing any costs that retailers incur in SEQ from the retail component would result in notified prices that are inconsistent with the UTP. Similarly, an adjustment to account for the different operating models in SEQ that may not be available to retailers in regional Queensland is not appropriate.[129] Additionally, setting notified prices based on the UTP results in electricity prices below the costs of supply for most regional customers due to the competitive nature of the SEQ electricity market.

As a result of improved publicly available data, we have estimated the retail cost allowances based on benchmarked costs weighted by the market share of each retailer[130], rather than a simple average (as in the 2016–17 determination). We consider that this approach better reflects the costs that retailers in SEQ incur and lessens the impact of any loss-leading offers put forward by retailers competing to increase their market share. This, combined with the removal of outliers from the analysis, should provide an appropriate representation of retail costs and avoid any substantial artificial lowering of these costs.[131]

While we note EQ's concerns regarding the use of 2020–21 data, we have based our estimates on these offers given it is the most recent data available and is most representative of current market conditions. We will consider whether it is appropriate to revisit our approach to estimating retail costs as part of the 2022–23 determination, if we are again delegated the task of setting notified prices.

Flat-rate tariffs as the basis for retail costs of all tariffs

Consistent with our approach in 2016–17, the estimates for flat-rate tariffs have been used as the basis for calculating retail costs for all tariffs. In addition to the estimates for flat-rate tariffs, we also considered deriving separate retail cost estimates for other tariff types (such as time-of-use and demand tariffs) by using the relevant market offers.

[126] ACIL Allen, *2021 - 22 regulated electricity price review – Updating retail costs*, draft report prepared for the QCA, March 2021.
[127] This is discussed in further detail in chapter 2.1 of ACIL Allen's draft report.
[128] Energy Consumers Australia, *Energy Consumer Sentiment Survey*, December 2020, p. 18.
[129] EQ, sub. 3, p. 13.
[130] Market share in this context refers to the number of customers served by each retailer.
[131] EQ, sub. 3, pp. 13–14.

However, our investigation has revealed such an exercise to be challenging. This is because the introduction of more complex time-of-use and demand network tariffs[132] has resulted in retailers adopting a variety of strategies for passing through these new network tariff charges and structures. That makes it difficult to assign appropriate network tariffs when undertaking the benchmarking analysis for these tariffs. In addition, there was a lack of appropriate consumption data for the time-of-use and demand tariffs.[133] We consider it is more appropriate to continue to use the estimates for the flat-rate tariffs as the basis to calculate retail costs for all tariffs for this year's review.

Adjusting for recent market developments

Given the potential for recent market and regulatory developments to impact the retail cost component for 2021–22, we considered the appropriateness of any adjustments for such developments. As the retail costs are estimated using 2020–21 market offers, an adjustment will only be necessary where developments in 2021–22 will result in a material change in cost relative to those incurred in 2020–21.[134]

We considered the impacts of covid-19, regulatory reform and potential productivity improvements, but there was no conclusive evidence to suggest that an additional adjustment is required.[135] This approach is broadly consistent with the AER's approach in its draft determination on the DMO for 2021–22.[136] After assessing potential step changes in retail costs, the AER considered that no specific adjustments were necessary. We will consider any further evidence provided in response to this draft determination as part of finalising our final determination.

Accordingly, our draft position for small customers is to establish two separate retail cost estimates to reflect the costs of supplying residential and small business customers, based on the outcomes of ACIL Allen's benchmarking analysis.

For a more detailed explanation of our considerations and ACIL Allen's approach, refer to Appendix D and ACIL Allen's methodology paper and draft report.

Large customers

We considered establishing new allowances for large and very large customers but propose to maintain our current approach for these customers due to the data quality issues identified. That is, setting the retail cost allowances using the established benchmark (set as part of the 2016–17 price determination), adjusted for inflation.

To update retail cost estimates for these customers, ACIL Allen proposed a bottom-up approach. An information request was issued to retailers to obtain the retail costs that are estimated to be incurred in 2020–21 to supply electricity to large and very large customers.[137] We received confidential data from five retailers—of these retailers, five provided data relating to large customers and four provided data relating to very large customers.

Given the limited number of data points and the variability of the data provided, we do not consider it is appropriate to use this data set as the basis for estimating the retail cost estimates

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[132] These tariff structures were introduced on 1 July 2020.
[133] This is discussed in further detail in Appendix D and in chapter 4.3 of ACIL Allen's draft report.
[134] Refer to chapter 5 of ACIL Allen's draft report.
[135] In August 2020, the AEMC made a rule change to allow some retailers to defer payment of network charges for customers impacted by covid-19. To date, no retailers have used the network charges deferral mechanism. For further information, see AER, *COVID-19 Retail market data dashboard—15 February 2021*, viewed 8 March 2020.
[136] AER, *Default Market Offer Prices 2021–22*, draft determination, 2021, pp. 60–72.
[137] This data is commercially sensitive and cannot be reproduced in this report.

for large and very large customers. The data set was of varying quality and highlighted differences in the way retailers categorise costs.[138] We note that EQ also expressed concern that the data they provided in relation to the 2020–21 financial year was largely a forecast rather than being reflective of actual costs incurred.

In view of these matters, we consider that it is more appropriate to maintain our current approach to updating the retail cost allowances for large and very large customers for this year's review. The current approach relies upon the results of a more thorough investigation of the efficient level of retail costs and has been benchmarked against allowances in other regulatory decisions and public information on these costs.[139] This approach also avoids the potential for cost biases resulting from relying on self-reported retail data.

On balance, we consider there is currently insufficient evidence to suggest that the retail cost allowances for large and very large business customers in 2021–22 should be materially different from those allowed in 2020–21. For large customer tariffs, we propose to adjust the 2020–21 fixed retail cost allowances for inflation and maintain variable retail cost allocators at 6.04 per cent (the same level established in the 2016–17 determination).

In previous determinations, we applied inflation to the historical retail cost estimates by using the average of the inflation forecasts (for the beginning and end of the notified price period) as published by the Reserve Bank of Australia (RBA) in its Statement on Monetary Policy (SMP). Using the most recently available SMP, this would provide an estimate of 2.25 per cent, the average of the June 2021 forecast of 3.0 per cent and the June 2022 forecast of 1.5 per cent.[140]

The RBA noted that the June 2021 inflation is impacted by the reversal of government support packages during the covid-19 period, such as free childcare and some other administered prices.[141] Given the short-term volatility in the inflation for June 2021, we are proposing to use the June 2022 inflation measure of 1.5 per cent.

For a more detailed explanation of our considerations and ACIL Allen's approach, refer to Appendix D and ACIL Allen's methodology paper and draft report.

Draft retail cost allowances included in notified prices

For residential customers, retail costs are expected to decrease, compared to 2020–21. For small business customers, a decrease in the fixed retail costs is offset by an increase in the variable retail costs. This movement reflects market data. The increase in the retail costs associated with the small business tariffs may be attributed to the more pronounced effect of covid-19 on small businesses.[142]

The chart below compares the residential and small business retail cost allowances included in our draft notified prices to the 2020–21 allowances.

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[138] Refer to Appendix D and chapter 6 of ACIL Allen's draft report.

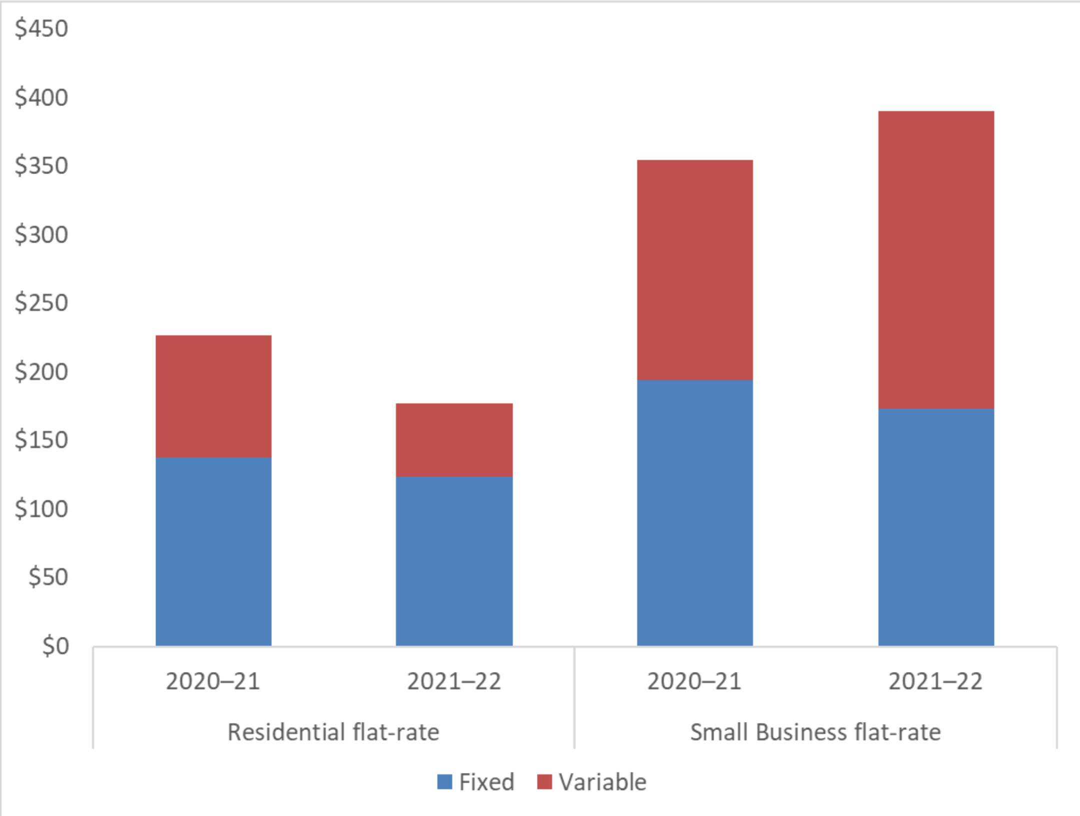
[139] Frontier Economics, *Retail Operating Costs*, report for the Economic Regulation Authority of Western Australia, March 2012, p. 6.

[140] RBA, *Statement on Monetary Policy*, February 2021.

[141] P Lowe, 'The Year Ahead', address to the National Press Club of Australia, Canberra, 3 February 2021.

[142] For example, the RBA reported that small businesses have been disproportionately affected by the covid-19 pandemic, as they are more likely to be in industries that have been harder hit by the pandemic (such as cafes, restaurants, arts and recreation.) See M Lewis and Q Liu, 'The COVID-19 Outbreak Access To Small Business Finance', *RBA Bulletin*, 17 September 2020.

Figure 4.5 Changes in retail cost allowances



Note: Retail cost allowances include regulatory fees.

Source: QCA analysis, using data from ACIL Allen and Energy Queensland.

The following charts compare the retail cost allowances included in the draft notified prices with the 2020–21 allowances. The comparison is by tariff type for typical small and large customers.[143] Actual costs will vary for individual customers with different levels of electricity usage.

[143] Typical customer consumption data was provided by Energy Queensland and Ergon Retail (see Appendix G).

Figure 4.6 Draft retail costs—typical customers on small customer tariffs (GST incl.)

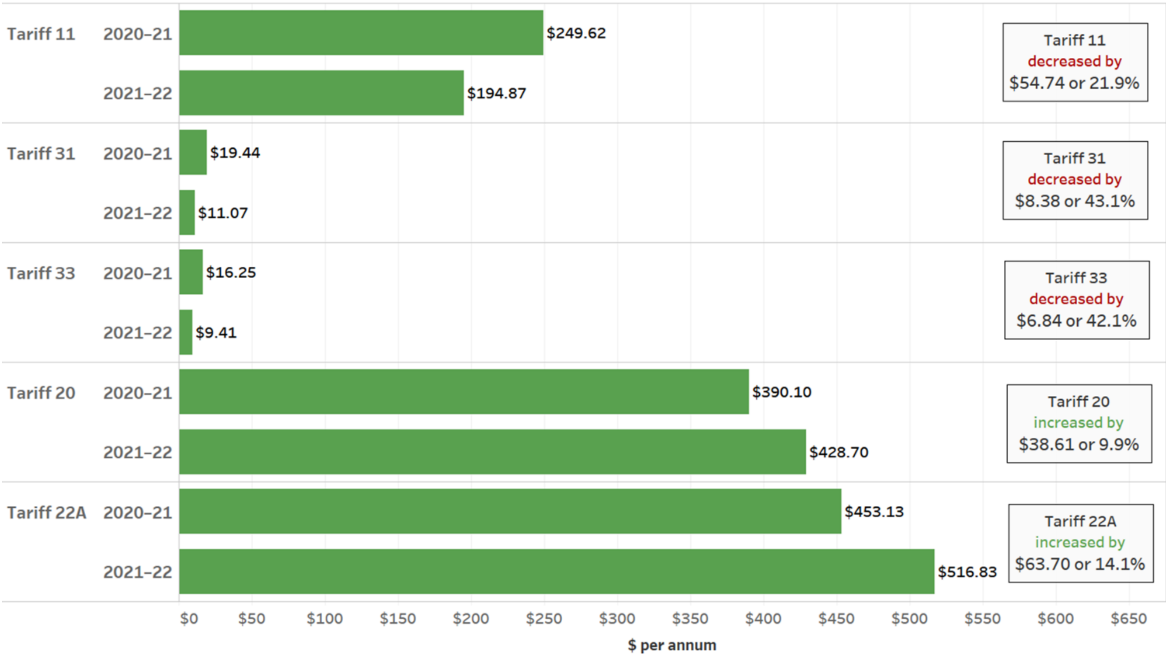
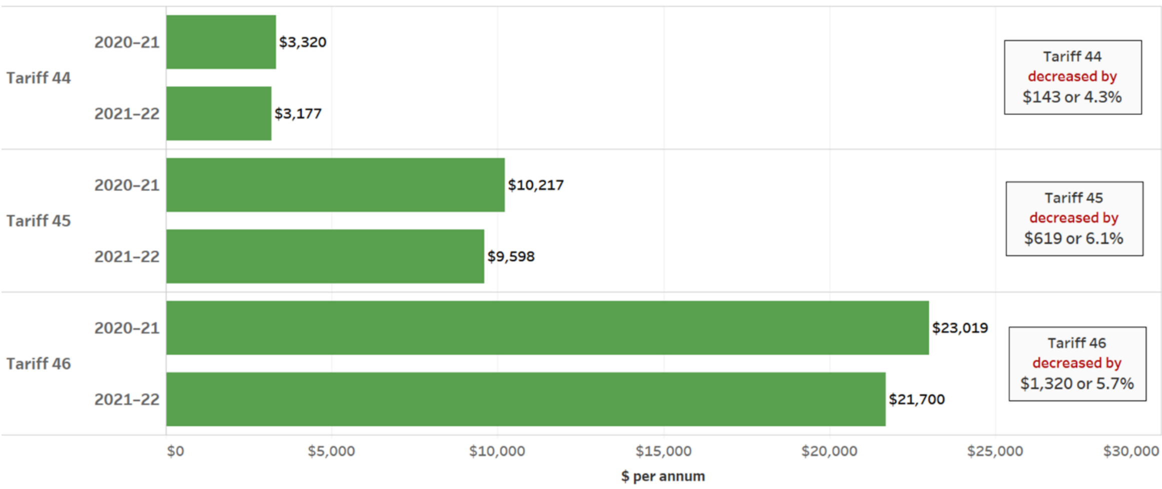


Figure 4.7 Draft retail costs—typical customers on large customer tariffs (GST incl.)



Note: Amounts are rounded to the closest dollar. Therefore, amounts may not add precisely. Percentage changes are based on unrounded amounts.

Application of draft retail cost allowances to proposed new retail tariffs

The terms of the delegation require us to consider making four new retail tariffs based on new network tariffs approved by the AER (discussed in Chapter 3):

- Transitional Network ToU Energy Tariff 1
- Transitional Network ToU Energy Tariff 2
- Transitional Network Dual Rate Demand Tariff 3
- Business customer (Basic)>100 MWh pa (large business).

Stakeholders did not comment on the approach to determining retail costs for these additional new tariffs.

Our draft position is to set the retail costs for the new tariffs using the same estimates (derived as part of this draft determination) for the existing tariffs.

For the three new small business tariffs, we considered setting the retail cost estimates based on the costs of supply in the Ergon east zone, transmission region one, given that the underlying network tariffs (for these retail tariffs) are only available in regional Queensland (but not in SEQ).

Despite this, we have not been presented with any information that retail costs for the Ergon east zone, transmission region one would differ materially from those to supply SEQ, so as to justify an alternative approach to our existing approach for setting notified prices.

Given the limited time and information available, we instead propose to adopt the retail cost estimates derived from ACIL Allen's benchmarking analysis for these new tariffs. That is, for the three new small business tariffs, we propose to apply the same relevant fixed and variable retail cost estimates used to determine the retail cost allowances for existing small business tariffs.

To estimate the retail costs for the new large business tariff, we propose to use the fixed and variable retail costs estimated for an existing large business tariff, tariff 44 (which targets smaller large business customers). In the absence of more reliable information, we consider this to be a conservative approach, as tariff 44 has the lowest fixed retail cost estimate among the most commonly accessed large business retail tariffs.

We consider this approach to be appropriate in the circumstances, as it ensures notified prices for existing and new tariffs are set in a consistent manner. We will consider any further comments provided in response to this draft position as part of finalising our final determination.

5 OTHER COSTS AND PRICING ISSUES

This chapter sets out our draft views on other costs and pricing issues, including any adjustments we need to consider when setting notified prices this year. Many of these matters are identified in the delegation and must be considered when setting notified prices. The matters discussed are:

- standing offer adjustment for small customers (section 5.1)
- headroom for large customers (section 5.2)
- cost pass-through (section 5.3)
- large customer metering costs (section 5.4)
- additional issues raised by stakeholders (section 5.5).

5.1 Standing offer adjustment—small customers

Matters in the delegation

The delegation requires us to consider incorporating a 'standing offer adjustment' amount in notified prices for small customers this year. This is intended to reflect the additional value that standard contracts provide compared to market contracts, for example, through additional protections contained in their terms and conditions.

The Minister said we 'should again consider including an adjustment similar to that applied in 2020–21 (i.e. 5 per cent of total costs of supply) that appropriately reflects this additional value.'[144]

In assessing the value of the adjustment, the delegation requires us to consider:

- the AER's DMO—should the application of this value result in a notified price bill that exceeds the equivalent DMO bill in SEQ, that value should be discounted such that the resulting bill does not exceed the equivalent DMO bill (provided that value is not discounted below zero)
- maintaining price relativity between tariffs—if a tariff is subject to the DMO adjustment described above, we must also consider discounting the value of other similar tariffs that are not subject to a DMO comparison to maintain price relativity. This involves comparing tariffs of the same type (primary or secondary) within a customer class (residential or small business).

While the delegation is broadly consistent with last year, discounting the value of other tariffs (not only those with an equivalent DMO) has not formed part of previous delegations and is a new matter for us to consider for this price determination.

[144] Appendix A: Minister's delegation, cover letter, p. 1.

Stakeholder comments

EQ supported continuing to include a standing offer adjustment into notified prices, to reflect the value that standard contracts provide compared to market contracts. Cotton Australia said the standing offer adjustment should be removed and Canegrowers said we should explain the basis for the 5 per cent mark-up as real costs are likely to be a fraction of this. [145]

Canegrowers said it may be possible for this to be assessed (the incidence and size of any average residual between market and standing contracts) as part of the retail cost review being undertaken by ACIL Allen. EQ also mentioned the retail cost review could be considered '...to ensure no duplication of cost recovery between these two components'.[146]

In the context of the new transitional tariffs, Canegrowers said notified price bills should not exceed the Energex DMO as it would be an unsustainable outcome under the UTP.[147]

EQ said any DMO adjustment should be aligned to only those tariff types that have a DMO price set by the AER, and any adjustment made to non-DMO-equivalent tariffs would not be aligned to the UTP.[148]

Analysis and draft position

Having regard to relevant factors, we consider it is appropriate to incorporate an adjustment into small customer notified prices as follows:

- level of the adjustment—we consider a 3.6 per cent value is appropriate and reflects the potential value of more favourable terms and conditions in standard contracts
- DMO comparison—no further adjustment is required, as the relevant draft notified price bills do not exceed the equivalent DMO bill in SEQ.

Level of the adjustment

We have assessed market data and other relevant factors this year to determine the appropriate value of the standing offer adjustment.

Supporting market data

The approach we applied in previous price determinations sought to use SEQ market contract costs (e.g. fees and charges a customer could incur) as a proxy for measuring regional Queensland standard contract benefits (e.g. fees and charges a customer could avoid[149]).

This year, we used recent market data to undertake a similar assessment, by:

- observing the range of fees and total charges in retail market contracts in SEQ
- identifying additional fees and costs in retail market contracts in SEQ, compared with standard contracts
- estimating the average additional costs that could be incurred by small customers in SEQ on retail market contracts.

[145] EQ, sub. 3, pp. 16, Cotton Australia, sub. 5, pp. 6.
[146] EQ, sub. 3, pp. 16.
[147] Canegrowers, sub. 6, pp. 3.
[148] EQ, sub. 3, pp. 3.
[149] More information on this approach is contained in chapter 6 of the QCA's 2019–20 final determination on notified prices.

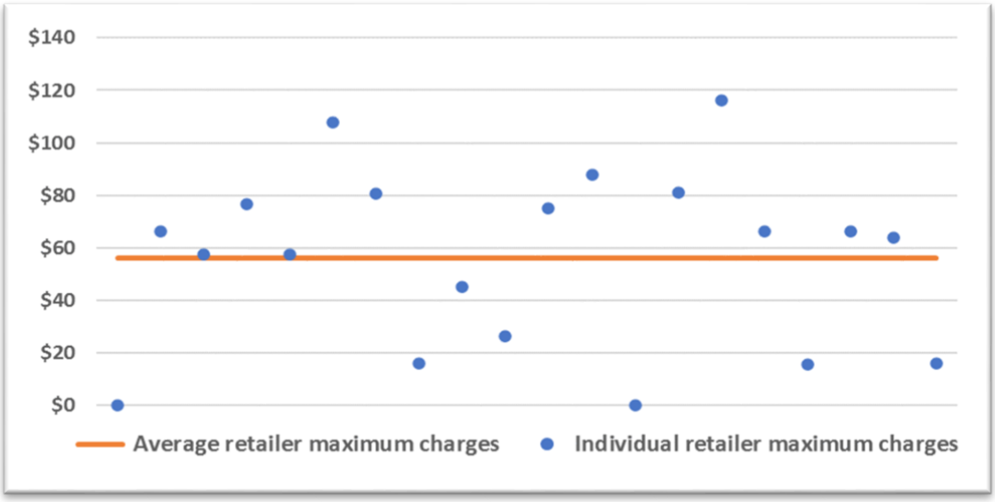
This approach is broadly consistent with the approach in previous price determinations, however, this year we took the average of the additional costs (rather than the maximum costs observed in the market[150]), which we believe better reflects the potential costs that may be incurred.

Using market data from the June quarter 2019–20[151], we found:

- there are additional costs associated with fees and charges in SEQ retail market contracts. Of the various types of fees and charges, most costs are associated with late payment fees (see figure 5.1)
- on average, $55 of additional fees could be incurred annually by an SEQ retail market contract customer. This is based on the annual fees and charges in SEQ market contracts compiled from individual retailers (see figure 5.2).

Figure 4 Type of SEQ retail market offer fees and charges for small customers[152]

Figure 5.2 Annual fees and charges in SEQ market contracts by retailer[153]



[150] A retailer that does not include any fees is excluded from the sample. As the purpose of the analysis is to assess what value retailers attach to terms and conditions (explicitly), the sample used must necessarily contain fees that retailers have explicitly valued separately to the cost of electricity supply.

[151] QCA, *SEQ retail electricity market monitoring 2019–20*, Chapter 4, 2019.

[152] Note, some fees are incurred annually (meter reads and account establishment fees).

[153] Two retailer market offers had zero 'additional costs' for the purpose of this assessment, that is there were no costs that could be incurred above those included in standard contract terms and conditions.

The additional costs associated with fees and charges, on average $55 annually, equates to around 3.6 per cent of a small customer's annual bill (based on a $1,527 annual bill).

We considered stakeholder comments around combining our assessment of retail costs and the standing offer adjustment, however the objective (and information) for assessing these matters is different. For instance, the retail cost assessment uses the residual component of market offers (by deducting network and energy costs) to estimate retail costs, whereas we need to assess the value of terms and conditions attached to contracts as part of this assessment. As such, we are satisfied the information we have used to assess the standing offer is appropriate and, given the separate nature and information used for this assessment, duplication of costs is not an issue that arises.

Using SEQ market contract data in the manner above to measure the value of standard contract benefits, the assessment would suggest an adjustment of 3.6 per cent is appropriate this year.

Other factors

There are other factors relevant to our assessment, including the matters in the delegation, stakeholder comments and our own assessment on recent market developments.

The delegation supports maintaining the level of the adjustment similar to that applied last year (i.e. 5 per cent of total costs of supply), which the Minister has said appropriately reflects the additional value of the more favourable standard contract terms and conditions.

Stakeholders had mixed views on this. EQ supported continuing to include an adjustment, but customers suggested it should be removed or reduced.

More broadly, recent market developments informed our assessment, particularly given these have impacted how customers and retailers interact in the market.

There have been recent regulatory reforms aimed at improving safety net provisions for consumers and influencing the way retailers communicate retail market offers to consumers.[154] As a result, market observations show:

- retailers have limited the use of conditional discounting and complex advertising to gain market share
- since the DMO was introduced in July 2019[155]:
  - bills for standing contract customers have decreased, i.e. the average annual bill decreased by 13.8 per cent in the September 2019 quarter
  - bills for market contract customers are less risky, i.e. there is less variance (increase) in bills if conditional discount obligations are not met. Also, the DMO reference bill must be used as the basis on which retailers offer discounts
  - the gap (or price differential) between market contract offers and standing contract offers has decreased, i.e. the average annual standing offer bills were $110 higher than average annual market offer bills in the September 2019 quarter, compared to being $262 higher in the June 2018 quarter.

[154] For instance, following the ACCC's 2018 retail electricity pricing inquiry, a suite of regulatory reforms were implemented to improve safety net provisions for all electricity consumers. In addition, the Electricity Retail Code introduced in July 2019 specified how retailer prices and discounts must be advertised, published or offered.

[155] QCA, *SEQ retail electricity market monitoring 2019–20*, 2019, pp. 10-11, 50.

We have also observed changes in retailers' market contract terms and conditions. For instance, there are less (or no) retailer penalties for switching retailers/ changing contracts. Also, more retailers are offering flexible payment options (e.g. monthly bills based on estimated usage, similar to bill smoothing available on standing offer contracts).

Given these market developments are still quite recent, and consumer understanding may take some time, we consider the terms and conditions attached to standing offer contracts may still provide some value to small customers. However, it is unclear whether standard contract terms and conditions will continue to offer value to customers in the future and, therefore, be a viable ongoing basis on which to make adjustments to small customer notified prices.

Having regard to the other factors detailed above, on balance, we consider the information available supports reducing the level of the adjustment to 3.6 per cent this year. Recent market developments suggest the value of standard contract terms and conditions has likely diminished due to broader improvements in retail market offers aimed at protecting consumers.

DMO comparison

We have not made any changes to the level of the adjustment based on the DMO comparison. This is because none of the notified price bills (based on draft notified prices in this report) exceeded the equivalent DMO bills. For more details on the DMO comparison, see Appendix F.

We will review this position in the final determination, based on the AER's final approval of the DMO (expected in April 2021).

5.2 Competition and headroom—large business customers

We are required to have regard to, among other things, the effect of the price determination on competition in the Queensland retail electricity market.[156]

Prior to the 2020–21 determination, we included a headroom allowance of 5 per cent (of total costs of supply) in notified prices for large and very large customers. The purpose of including headroom was to promote retail competition in this market segment, including by potentially incentivising retailers to enter the market and compete for customers.

Last year, we did not include a headroom allowance in notified prices. We considered there was no compelling evidence headroom was effective in promoting competition.[157]

Stakeholder submissions

Customers supported continuing to exclude the headroom allowance from notified prices for large customers, including because it does not play any role in promoting competition in the Ergon Network area.[158]

Analysis and draft position

In the absence of new, compelling evidence, we remain of the view that including a headroom allowance is unlikely to further promote competition in the large customer market.

As such, our draft position is not to include a headroom allowance in notified prices for large customers this year.

[156] Section 90(5)(a)(ii) of the Electricity Act.
[157] QCA, *Regulated retail electricity prices 2020–21*, final report, 2020, p. 38.
[158] QFF, sub. 1, p. 4; Cotton Australia, sub. 5, p. 6.

5.3 Cost pass-through mechanism

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

Consistent with our approach in previous determinations, we propose to provide for the pass-through of small-scale renewable energy scheme (SRES) costs in this determination.

SRES cost pass-through

Retailers incur SRES costs based on the number of certificates that they are required to purchase and surrender to the Clean Energy Regulator (CER). The CER determines these SRES liabilities for each calendar year, but notified prices are determined for each financial year.

Generally, at the time of our final determination for notified prices, only the SRES liabilities for the first half of the financial year are known, while liabilities for the second half are based on the forecasts from the CER. The CER typically determines the final SRES liabilities for the second half of the financial year about nine months after our final determination.

Such an arrangement can lead to an over- or under-recovery of SRES costs if there are discrepancies between the CER's forecast and its final determination of the SRES liabilities. To account for the over- or under-recovery SRES costs, we propose to apply a cost pass-through mechanism.

Analysis and draft position

For the draft determination, ACIL Allen has updated the CER's forecast of SRES liabilities for 2021 to reflect the most recent developments in the uptake of small-scale renewable energy systems (discussed in Appendix C). The update has resulted in higher than expected SRES liabilities. This means that retailers are likely to be required to purchase more certificates to surrender to the CER than initially estimated—leading to an under-recovery of SRES costs for 2020–21 and an increase in usage charges for all retail tariffs for 2021–22.

For further detail on how the SRES cost pass-through was estimated, see Appendix E.

Our draft position is to include the under-recovery of 2020–21 SRES costs in 2021–22 notified prices. We consider this to be appropriate, given that it aligns notified prices with the UTP-consistent costs of supply.

The CER is expected to determine the final 2021 SRES liabilities in March 2021. Therefore, we will update the SRES liabilities in our final determination.

Depending on the regulatory framework for future price determinations and whether changes are made to the UTP, 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.

5.4 Large customer metering costs

Consistent with previous determinations, we have separated the large customer metering costs for advanced digital meters from retail costs and estimated these metering charges separately.

Also consistent with previous determinations, we have estimated metering charges based on the latest confidential data provided by retailers. We averaged this data to produce cost estimates for each large customer type.

Overall, the draft metering costs have decreased for connection asset customers and individually calculated customers and increased for standard asset customers.

The metering charges for large customers are set out in Chapter 6.

5.5 Additional issues raised by stakeholders

This table addresses stakeholder issues raised not addressed elsewhere in this report.

Table 5.1 Additional issues raised in stakeholder submissions

Stakeholder comment	*Our* ***response***
CPAQ said small and large businesses that sign contracts with a retailer (other than Ergon Energy Retail) should have the ability to return to Ergon Energy Retail.[159]	Large business customers are restricted from returning to Ergon Energy Retail by operation of s.19C of the *National Energy Retail Law* (Queensland), which reflects the Queensland Government's 'non-reversion policy'.[160] Given this, we cannot review (or amend) such arrangements as part of our price review; this is a matter for the Queensland Government.
Cotton Australia said we should allow all irrigators to be able to access the large customer load control tariffs (tariffs 60A and 60B), regardless of their location, or alternatively allow existing large customers who access obsolete tariffs 62, 65 and 66 to access the new transitional network tariffs.[161]	The large customer load control tariffs require network signalling equipment to be installed in order to function (this equipment allows the distributor to control the energy supply). While we understand the desire for these tariffs to be available in all areas, we cannot review (or direct) distributors to install signalling technology; network infrastructure and investment is a matter for the distributor and we encourage customers to engage with their retailer and EQ on tariff options to meet their circumstances.
CPAQ said additional tools and information should be made available to businesses about the different tariffs and it provided information about its members' understanding of tariff options.[162]	We encourage retailers to engage with their customers and provide tailored information on the tariff options available to them. It is important that customers understand which tariffs best meet their circumstances to enable them to make informed decisions.
Canegrowers indicated that distribution network service provider tariffs do not conform to the network pricing objective and the long run marginal cost pricing principle.[163]	We cannot review (or amend) network tariffs as part of our pricing review. The network prices and tariff structures form part of the AER's regulatory review process and annual price setting process for Ergon Distribution and Energex. Stakeholders can participate in the AER's public regulatory process, including providing comments on the network pricing, as part of these reviews.
EQ supported the removal of the EasyPay Rewards scheme from the tariff schedule, as all obligations under this scheme have been finalised.[164]	We have removed the EasyPay Rewards scheme from the tariff schedule given it is no longer current (the scheme expired on 1 September 2020).
EQ supported retaining in the tariff schedule the two exceptions to the application of kVA	We have retained the two exceptions to the application of kVA charging. That is:

[159] CPAQ, sub. 2, p. 5.
[160] In 2018, the Queensland Government removed the non-reversion policy for residential and small business customers.
[161] Cotton Australia, sub. 5, p. 4.
[162] CPAQ, sub. 2, pp. 5–6.
[163] Canegrowers, sub. 6, p. 5.
[164] EQ, sub. 3, p. 17.

Stakeholder comment	*Our* ***response***
charging parameters for large customer tariffs.[165]	• for customers with type 6 metering, the charging parameter will continue to be kW • where type 6 metering is replaced with type 1 to 4 metering due to fault, age, distributor-initiated customer reclassification or other action not initiated by the customer, the charging parameter will be either kW or kVA at the customer's choice until the first anniversary of the meter replacement, and kVA from that time. We note, we have removed the provision in the tariff schedule allowing large customers to choose whether a kW or kVA charging parameter is applied, given this provision expires on 30 June 2021 (the tariff schedule for prices set in this review will commence after this date, on 1 July 2021).

[165] EQ, sub. 3, p. 17.

6 DRAFT NOTIFIED PRICES

This chapter sets out the draft notified prices for 2021–22. A breakdown of the draft notified prices by cost component is provided in Appendix H. The draft gazette notice, which includes the draft notified prices published in a tariff schedule, and the eligibility criteria and terms and conditions for accessing each tariff, is provided in Appendix I.

Table 6.1 Draft notified prices—residential customers (excl. GST), 2021–22

Retail tariff	***Fixed[a]***	***Usage***			***Demand***	
		Off-peak/flat	***Shoulder***	***Peak***	***Off-peak***	***Peak***
	c/day	***c/kWh***	***c/kWh***	***c/kWh***	***$/kW/mth***	***$/kW/mth***
Tariff 11—residential (flat-rate)	88.317	19.400				
Tariff 12A—residential (time-of-use)[b]	70.506	16.166		51.490		
Tariff 12B—residential time-of-use[c]	88.317	14.290	16.018	25.846		
Tariff 14—residential seasonal (time-of-use demand)[d]	43.091	12.732			7.110	49.506
Tariff 14A—residential time-of-use demand[e]	87.073	16.426			2.559	
Tariff 14B—residential time-of-use demand[e]	87.073	13.663			7.308	
Tariff 31—night rate (super economy)		12.390				
Tariff 33—controlled supply (economy)		13.808				

a *Charged per metering point.*

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

c *Peak usage—4 pm to 9 pm; shoulder (night) usage—all other times; off-peak (day) usage—9 am to 4 pm.*

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

e *Demand—4 pm to 9.00 pm all days.*

Table 6.2 Draft notified prices—small business and unmetered supply customers (excl. GST), 2021–22

Retail tariff	*Fixed[a]*	*Usage*		*Demand*	
		Off-peak/flat	*Peak*	*Off-peak/flat*	*Peak*
	c/day	*c/kWh*	*c/kWh*	*$/kW/mth*	*$/kW/mth*
Tariff 20—business (flat-rate)	120.957	22.135			
Tariff 22A—business (time-of-use)[b]	111.143	20.484	54.696		
Tariff 24—business (time-of-use demand)[c]	57.732	14.900		7.487	74.511
Tariff 24A—business (time-of-use demand)[d]	119.713	20.763		2.397	
Tariff 24B—business (time-of-use demand)[d]	119.713	18.261		9.565	
Tariff 34—business (interruptible supply)	110.907	15.900			
Tariff 41—low voltage (demand)	625.903	13.275		18.344	
Tariff 91—unmetered		18.996			

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).*

d *Demand—4 pm to 9 pm on weekdays.*

Table 6.3 Draft notified prices—small business customers (excl. GST), 2021–22

Retail tariff	***Fixed band[a]***					***Usage***		
	Band 1	***Band 2***	***Band 3***	***Band 4***	***Band 5***	***Off-peak/flat***	***Shoulder***	***Peak***
	c/day	***c/day***	***c/day***	***c/day***	***c/day***	***c/kWh***	***c/kWh***	***c/kWh***
Tariff 20A—small business inclining-band	120.957	150.275	179.594	208.913	238.335	22.135		
Tariff 22B—small business time-of-use inclining band [b]	120.957	150.275	179.594	208.913	238.335	18.270	21.237	30.354

a *Fixed band 1—0MWh to 20MWh annual consumption; fixed band 2—20MWh to 40MWh annual consumption; fixed band 3—40MWh to 60MWh annual consumption; fixed band 4—60MWh to 80MWh annual consumption; fixed band 5—80MWh and above annual consumption.*

b *Peak usage—4 pm to 9pm weekdays; shoulder (night) usage—all other times; off-peak (day) usage—9 am to 4 pm all days.*

Table 6.4 Draft notified prices—large business and street lighting customers (excl. GST), 2021–22

Retail tariff	***Fixed***	***Usage***		***Demand***			***Excess demand***
		Off-peak/flat	***Peak***	***Off-peak/flat***[a]	***Peak***	***Flat***[a]	
	c/day	***c/kWh***	***c/kWh***	***$/kW/mth***	***$/kW/mth***	***$/kVA/mth***	***$/kVA/mth***
Tariff 44—over 100 MWh small (demand)	4042.704	10.005		24.891		22.402	
Tariff 45—over 100 MWh medium (demand)	13148.598	10.005		19.786		17.807	
Tariff 46—over 100 MWh large (demand)	34279.916	10.005		16.239		14.615	
Tariff 50—over 100 MWh seasonal time-of-use (demand)[b]	3387.138	11.786	9.776	10.027	67.919		
Tariff 50A—large business time-of-use demand[c]	15845.438	10.274				13.520	2.704
Tariff 60A—large business flat-rate interruptible supply (primary)	4042.704	17.231					
Tariff 60B—large business flat-rate interruptible supply (secondary)		17.231					
Tariff 71—street lighting		22.659					

a *Customers on tariffs 44, 45 and 46 will be charged for demand on either a kW or kVA basis, based on their metering arrangements.*

b *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).*

c *Demand—4 pm to 9 pm weekdays.*

Table 6.5 Draft notified prices—very large business customers (excl. GST), 2021–22

Retail tariff	***Fixed***	***Usage***	***Connection unit***	***Capacity***	***Demand***
	c/day	***c/kWh***	***$/day/unit***	***$/kVA of AD/mth***	***$/kVA/mth***
Tariff 51A—high voltage (CAC 66 kV)	24922.052	9.527	5.928	3.425	3.191
Tariff 51B—high voltage (CAC 33 kV)	18364.552	9.527	5.928	4.183	3.305
Tariff 51C—high voltage (CAC 22/11 kV Bus)	17228.652	9.527	5.928	4.825	4.007
Tariff 51D—high voltage (CAC 22/11 kV Line)	16579.652	9.527	5.928	9.353	8.084
Tariff 53—high voltage (ICC)	24736.881	9.527		3.425	3.191
ICC site-specific—high voltage	2494.281	8.308		0.195	0.182

Table 6.6 Draft notified prices—very large business customers (excl. GST), 2021–22

Retail tariff	*Fixed*	*Usage*		*Connection unit*	*Capacity*	*Demand*
		Off-peak	*Peak*			
	c/day	*c/kWh*	*c/kWh*	*$/day/unit*	*$/kVA of AD/mth*	*$/kVA/mth*
Tariff 52A—high voltage (CAC STOUD 33-66 kV)	13902.252	9.515	9.198	5.928	6.045	12.098
Tariff 52B—high voltage (CAC STOUD 22/11 kV Bus)	13902.252	9.515	9.198	5.928	4.266	45.572
Tariff 52C—high voltage (CAC STOUD 22/11 kV Line)	13902.252	9.515	9.198	5.928	7.823	79.554

Table 6.7 Draft notified prices—large business customers (excl. GST), 2021–22

Retail tariff	*Fixed*	*Usage*[a]	
		Below threshold	*Above threshold*
	c/day	*c/kWh*	*c/kWh*
Tariff 43—Business customer (over 100 MWh)	4042.704	9.962	19.180

a *Usage (below threshold)—up to 97,000 kWh per year; usage (above threshold)— 97,000kWh per year and above.*

Table 6.8 Draft limited-access obsolete tariffs—small business customers (excl. GST), 2021–22

Retail tariff	*Fixed*	*Usage*			*Capacity*	
		Block 1/ Peak	*Block 2*	*Off-peak/flat*	*Up to 7.5kW*	*Over 7.5kW*
	c/day	*c/kWh*	*c/kWh*	*c/kWh*	*$/kW*	*$/kW*
Tariff 62A—time-of-use declining block tariff[a]	102.037	50.509	42.253	15.936		
Tariff 65A—time-of-use tariff[b]	101.737	39.556		20.450		
Tariff 66A—dual–rate demand tariff	204.237			19.275	3.573	10.789

a *Block 1—7am to 9pm on weekdays (first 10,000 kWh per month); Block 2—7 am to 9 pm on weekdays (remaining kWh per month); off-peak—all other times.*

b *Peak—a fixed 12 hour period as agreed between the retailer and customer from the range 7am to 7pm, 7.30am to 7.30pm or 8am to 8pm; off-peak—all other times.*

Table 6.9 Draft obsolete tariffs—large business customers (excl. GST), 2021–22

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

Table 6.10 Draft metering charges—small customer advanced meters (excl. GST), 2021–22

Description	***Charge Type***	***Metering charge (c/day)***
Primary tariff	Capital	7.094
	Non-capital	3.324
Secondary tariff	Capital	2.049
	Non-capital	0.987

Source: Data from Energy Queensland.

Table 6.11 Draft metering charges—large and very large business customers advanced meters (excl. GST), 2021–22

Customer type	***Metering charge (c/day)***
Standard asset customer (annual usage of 750 MWh or less)	196.975
Standard asset customer (annual usage greater than 750 MWh)	233.770
Connection asset customer	429.862
Individually calculated customer	439.848

Source: Retailer data.