Queensland Competition Authority

Final determination

Regulated retail electricity prices for 2021–22

Regional Queensland

June 2021

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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).

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 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. [1]

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

Matters we must consider under the delegation

The terms of reference in the Minister's delegation sets out matters relevant to our price determination we must consider 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
- 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, for example holding stakeholder workshops on key issues.

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

[1] Electricity Act, s.90(5)(a).
[2] Electricity Act, s. 90(5)(b).

1.3 Review process and consultation

This final determination contains notified prices, presented as bundled prices appropriate to the retail tariff structure (except for site-specific tariffs), to apply in 2021–22.[3] In making this determination, we have had regard to relevant factors in the Electricity Act, matters in the delegation, stakeholder submissions received throughout our review process, as well as our own analysis.

This is the final stage of this year's review process. The notified prices set out in this price determination will apply from 1 July 2021. All reports and public stakeholder submissions are available on our website.[4] The key review dates, including when we published reports and consulted with stakeholders, are set out below.

1.4 Human Rights Act declaration

As required by s. 58 of the *Human Rights Act 2019* (Qld), 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 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.

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[3] As required in cl. 8 of the terms of reference (Appendix A).
[4] We note EQ provided a confidential submission on the draft determination which was later withdrawn.

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 final determination is structured as follows:

- Indicative customer bill impacts (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)
- Individual cost components (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)
- 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 notified price customer 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 main report (not as a substitute).

Consultant's reports

We engaged ACIL Allen to assist us in setting 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).

These reports have been 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: Default market offer comparison
- Appendix G: Data used to estimate customer impacts
- Appendix H: Build-up of notified prices
- Appendix I: Gazette notice.

2 INDICATIVE BILL IMPACTS

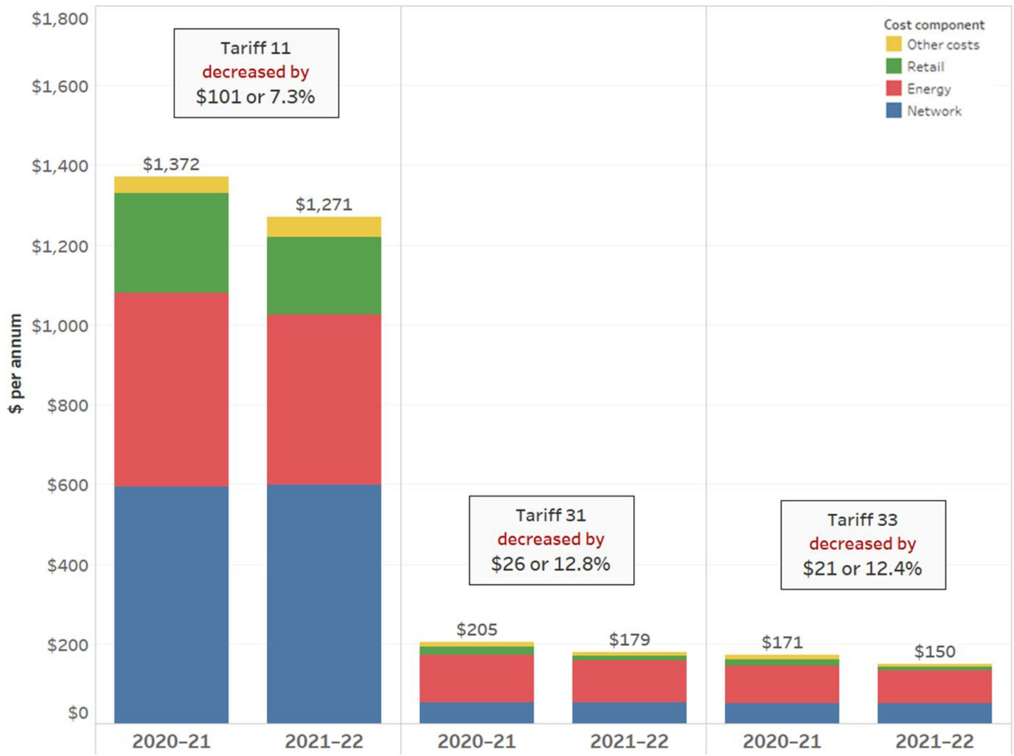
Overall, typical customers[5] on all major tariffs can expect a decrease in their electricity bills based on the final 2021–22 notified prices, compared to bills based on the 2020–21 notified prices (see figures below).[6] This decrease is largely due to a decline in estimated energy costs, which is partially offset by an increase in network costs.[7]

Importantly, an individual customer's actual bill will vary from our indicative bills depending on how much and when electricity is used. We strongly recommend that customers engage with their retailer for further advice and information tailored to their individual circumstances.

2.1 Residential customers

Typical customers on the main residential tariffs (tariffs 11, 31 and 33)[8] are expected to pay around 7.3 to 12.8 per cent less for their electricity in 2021–22 (see figure below).[9]

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.

[5] 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).

[6] The final notified prices are set out in Chapter 6.

[7] Individual cost components of notified prices are discussed in Chapter 4.

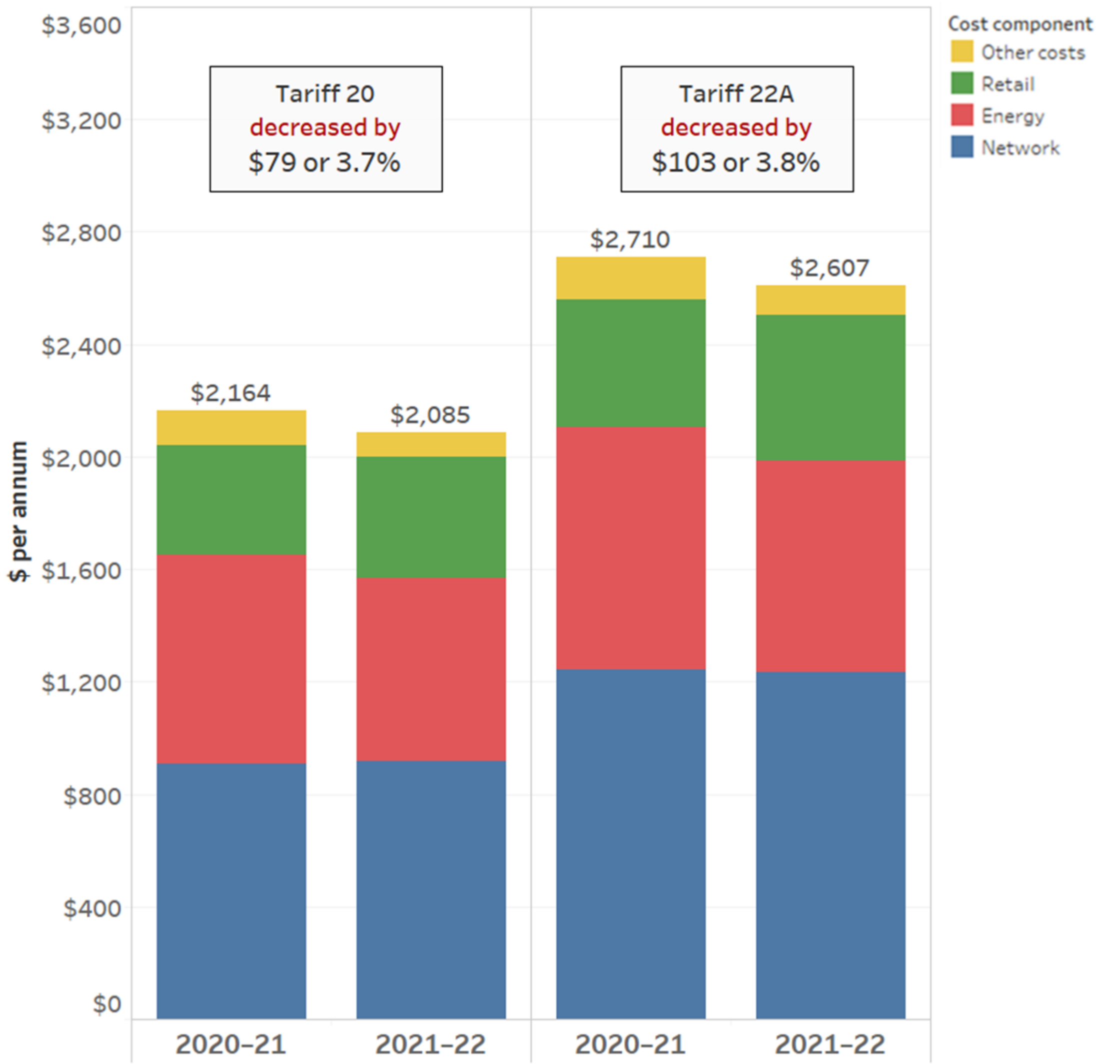
[8] Most residential customers are on tariff 11, but many customers also access load control tariffs—tariffs 31 and 33—for appliances that do not require a constant supply of electricity (e.g. hot water systems and pool pumps).

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

2.2 Small business customers

Typical customers on the main small business tariffs (tariffs 20 and 22A)[10] are expected to pay around 3.7 to 3.8 per cent less for their electricity in 2021–22 (see figure below).[11]

Figure 2.2 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.

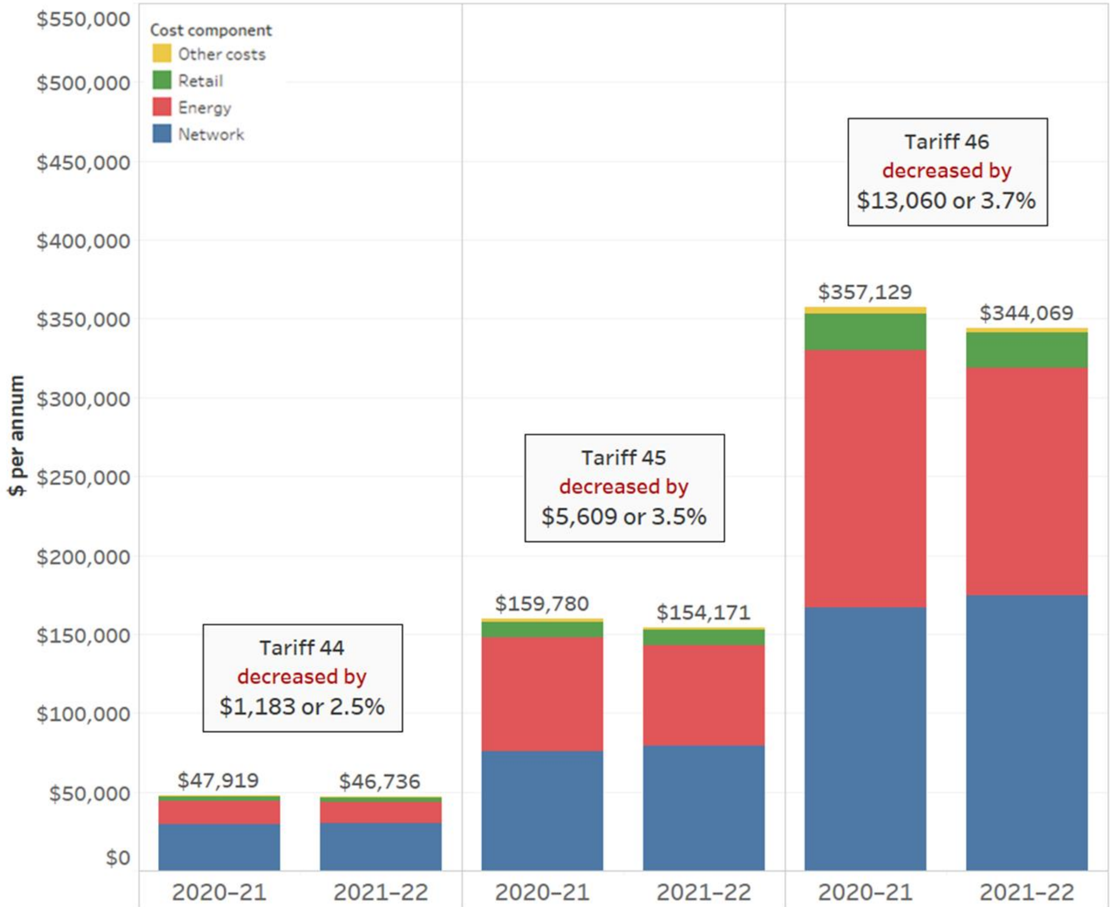
[10] Tariff 20 is a flat-rate tariff, and tariff 22A is a time-of-use tariff.

[11] 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 tariffs 44, 45 or 46 are expected to pay around 2.5 to 3.7 per cent less for their electricity in 2021–22 (see figure below).[12]

Figure 2.3 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.

[12] 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 views on key issues we considered in this year's price determination, including overarching framework matters that affect 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 provided broad considerations we must have regard to when setting notified prices and additional considerations impacting how we set the new retail tariffs, and the terms and conditions for accessing tariffs contained in the tariff schedule.[13]

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

The matters we discuss here 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 released the DMOs for the coming year on 27 April 2021
- the ongoing network tariff reforms—the AER sets network revenues and tariffs for energy distributors in Queensland, namely Energex and Ergon Energy Network (Ergon Network). As part of the 2020–25 regulatory determination process, the AER approved new network tariffs with more complex structures for distributors. The new tariffs are 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 (more information new tariffs in section 3.3)
- 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

[13] The current 2020–21 tariff schedule of regulated retail electricity prices is available on our website.

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 refer to the DMO and network reforms as important considerations this year, with additional matters included in the delegation to reflect this.

We 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

The delegation requires us to consider various policies, principles and other matters, including:

- 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 Network plus Retail (N+R) cost build-up methodology, including applying this approach flexibly for setting some small customer retail tariffs that no longer have an underlying network tariff (i.e. tariffs 12A, 14, 22A, and 24).[14]

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 delegations in previous years and our approach to setting notified prices in previous price determinations—with some new matters relevant to setting the new retail tariffs.

We considered approaches for setting notified prices that take account of these matters, including having regard to the government's UTP and using the N+R cost build-up methodology to set notified prices.

Stakeholder comments

Several stakeholders said the cost of electricity continues to be a key issue in regional Queensland[15], and while steps have been taken to improve electricity prices in Queensland, several network reform issues are still to be addressed and pricing structures could be more simplified and transparent, so customers can more easily make informed business decisions.[16]

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. However, EQ did not agree that new retail tariffs must be set based on network tariff structures. Further, EQ considered this an

[14] Appendix A: Minister's delegation, terms of reference, clause 2(e).
[15] QEUN, sub. 12, pp. 1–8; Etrog, sub. 14, pp. 3–4.
[16] Canegrowers, sub. 6, pp. 3,2, ii and 7; QFF, sub. 1, p. 4.

opportune time to explore and review retail tariffs, with the intent to offer tariff structures that better suit the needs of regional electricity customers.[17]

EQ also said:

- 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 by 30 June 2022, 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, such as incorporating time-of-use retail costs into existing time-of-use tariffs.[18]

QFF supported the introduction a of broad suite of tariffs that provide additional and valuable tariff options to small customers. However, QFF said:

- it is disappointing and unacceptable that the QCA continues to dismiss industry concerns and has not introduced more diverse and flexible tariff structures, or provided equitable and sustainable prices for farmers, including prices that reflect the seasonal use of electricity by the agricultural sector
- education around new and replacement tariffs is essential, as there is currently no information to help guide and prepare the agricultural sector on what tariffs are best suited to their business.[19]

Some stakeholders suggested the community service obligation payment (CSO) should be paid to Ergon Network, not Ergon Energy Retail (Ergon Retail), to increase competition with other retailers.[20] Moreover, QEUN called for the transparent reporting of how the UTP and CSO are defined and calculated.[21]

Analysis and final position

We considered the matters raised by stakeholders in the context of our review.

Stakeholders commented on a range of matters, some of which go beyond the scope of our review. The framework in which we operate sets boundaries for considering how notified prices should be set (see section 1.2). The Minister's delegation does not unlock investigative and decision-making powers to assess broad industry-related concerns (e.g. tariff education, diversity, and affordability for particular industry groups in regional Queensland) or implement measures proposed by stakeholders aimed at addressing these concerns (e.g. reducing electricity prices and introducing a range of bespoke or new retail tariffs). This also applies to the concerns QEUN raised around government CSO funding and reporting, which arise in connection with the

[17] EQ, sub. 8, p. 2.
[18] EQ, sub. 3, pp. 5, 12, 17, sub. 8, pp. 2–3.
[19] QFF, sub. 7, pp. 3–5.
[20] QFF, sub. 7, p. 5; Canegrowers, sub. 11, p. 3; QEUN, sub. 12, pp. 30–31.
[21] QEUN, sub. 14, p. 36.

development and operation (legislation and policy) of the overarching framework, rather than how a particular task is performed within this framework (our role in setting notified prices).

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:
  - for small customers—on the costs of supply in SEQ (Energex pricing region)
  - for large business customers—on the costs of supply in the Ergon 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 our approach to setting notified prices in previous price determinations. In doing so, we have not, as EQ suggested[22], sought to review retail tariffs with a view to offering new tariff structures or condensing the suite of existing retail tariffs available. Rather, we have maintained the existing approach of basing retail tariffs on network tariff structures (where available). The N+R approach is understood by stakeholders and has been applied for some time under our pricing framework, resulting in retail tariffs that reflect the structure of their respective underlying network tariffs. As such, it is not clear what new retail tariffs EQ has in mind to offer, or the basis on which they would be calculated.

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 CSO subsidy to Ergon Retail (expected to be $454 million in 2020–21)[23]
- 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 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:

[22] EQ, sub. 3, pp. 5, 12, 17, sub. 8, pp. 2–3.
[23] Queensland Government, *Budget Strategy and Outlook 2020–21*, Budget Paper 2, December 2020, p. 200.

- the three new load control tariffs that commenced in November 2020
- a suite of eight additional retail tariffs that commenced in January 2021[24]
- 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[25]
- we are required to consider maintaining all existing standard tariffs, unless otherwise set out in the delegation. This includes tariffs 12A, 14, 20A, 22A, 24 and 41 identified by EQ[26]
- stakeholders indicated support for the additional optionality provided through the introduction of new retail tariffs.

That said, in the future it would be possible to review 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 we are delegated the task, this type of review could occur in future price determinations, and EQ could use the additional time to get useful feedback from customers on the workability of the suite of current tariffs, particularly on those tariffs EQ identified to be removed.

3.3 Approach for setting 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 Network'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.

[24] For more information on the new tariffs introduced, see our Supplementary notified price determination 2020–21.
[25] See the Minister's cover letter and delegation to the QCA, 2020–21 supplementary notified price review, June 2020.
[26] Appendix A: Minister's delegation, terms of reference, clause 2(h).

According to Ergon Network's TSS[27], these network tariffs:

- will commence from 1 July 2021 and are intended to mirror the tariff structures of obsolete retail tariffs 62, 65 and 66[28] (due to expire on 30 June 2021)
- will be grandfathered immediately, available to existing small business customers in the Ergon east zone region that accessed the corresponding obsolete retail tariff between 1 July 2017 and 30 June 2020.

When we set these tariffs, we must consider specific matters that are set out in the delegation:

- the price level—basing the network cost component on the relevant Ergon Network charges for 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 the Ergon east zone region); instead, these tariffs should be available to eligible customers across all Ergon regions.

On that basis, we have considered 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 made several 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[29]
  - the new tariffs contain material price increases relative to existing obsolete tariffs. Further, large customers unable to access the new tariffs will face significant increases in fixed charges as they move to standard large customer tariffs. It recommended we identify and report the likely bill impacts for customers moving to the new tariffs or to large customer tariffs.[30]
- Cotton Australia, QFF and Agforce said large customers who have accessed the obsolete retail tariffs from 1 July 2017 should not be excluded from accessing the new tariffs.[31]

[27] Ergon Energy, *Ergon Energy Tariff Structure Statement 2020–25*, June 2020 (Erratum: version 6, August 2020, pp. 24–25).
[28] Customers on obsolete tariff 66 should note the corresponding new AER-approved network tariff structure is not mirrored in all respects, it has a monthly dual-rate capacity charge, instead of an annual dual-rate capacity charge.
[29] Canegrowers, sub. 6, p. 1, attachment, pp. 5–6, sub. 11, p. 2.
[30] Canegrowers, sub. 6, pp. 1–2.
[31] Cotton Australia, sub. 5, p. 3, sub. 9, p. 2; QFF, sub. 1, pp. 2–3, sub. 7, p. 3; Agforce, sub. 10, p. 2.

- QFF asked us to clarify what tariffs customers will be transferred to if they do not choose an alternative tariff prior to their obsolete tariff expiring.[32]
- Ergon Retail said:
  - there is scope to depart from the network tariff conditions for these tariffs. It recommended that we limit access to customers who remain on the expiring obsolete tariffs on 30 June 2021 (i.e. eligibility should not be backdated to 1 July 2017). Ergon Retail said it has invested heavily in working with stakeholder groups and customers, and allowing customers on non-obsolete tariffs to opt in to the new tariffs goes against Ergon Network's strategy to transition customers towards greater cost reflectivity[33]
  - its preference is for eligible customers to be given 12 months to opt in to these tariffs, after which the tariffs will be closed to new customers.[34]

Analysis and final position

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

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

Pricing approach

We have set the new transitional retail tariffs by:

- basing the price level on the relevant Ergon Network prices for east zone transmission region one approved by the AER
- using the N+R methodology—we built 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 added the R component (i.e. energy and retail costs) determined by us.

While the new transitional tariffs are set in a similar manner to other notified prices, the cost considerations are different. That is, while the usual approach under the UTP for small customers bases network costs on Energex network prices, we consider that basing the network costs for these tariffs on the relevant Ergon 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
- are 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 the Ergon pricing region 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).

[32] QFF, sub. 7, p. 4.
[33] EQ, sub. 8, p. 4.
[34] EQ, sub. 8, p. 4.

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 that:

- 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[35] 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 used the network prices and tariff structures that the AER approved for Ergon Network as the basis for setting notified prices. We cannot review (or amend) the network price levels or tariff structures, as Canegrowers suggested, so that customers receiving deeply discounted prices continue to do so.

We do not consider it appropriate to establish retail tariff structures 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 (including 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—for example, tariff 22B (the small business time-of-use inclining band tariff) and tariffs 24A and 24B (the small business time-of-use monthly demand tariffs). As such, customers currently on the obsolete retail tariffs (or considering accessing these new transitional tariffs) should consult Ergon 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.

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 the Ergon east zone pricing region). 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

[35] Note that the new AER-approved structure for the network tariff that is based on obsolete tariff 66 has a monthly dual-rate capacity charge, instead of an annual dual-rate capacity charge.

to the retail level this geographic element of the network tariff requirements, although it did note this will mean that the alignment between network and retail tariffs will not always be achievable.[36] However, we do not consider this to be significant, given that network and retail tariffs for customers on obsolete retail tariffs are not currently aligned.

Some stakeholders requested that the new 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.

EQ commented that Ergon Network's rationale for limiting access to small business customers was to minimise cross-subsidisation to the maximum extent possible (as required by the National Electricity Rules) and reflect the fact large customers are more likely to have smart meters (greater network tariff options and ability to mitigate bill impacts). EQ also noted large customers with basic metering would be able to access the new basic meter tariff (see section 3.3.2). EQ further stated that industry-specific network tariffs would not be approved by the AER, as they would not comply with the pricing principles.[37]

This means existing large business customers accessing obsolete tariffs will not be able to access the new transitional tariffs. However, as noted above, these are new tariffs, which are not a continuation of the obsolete retail tariffs. We encourage these customers to contact Ergon Retail and explore the alternative retail tariffs available to them.

We have applied the grandfathering arrangements of the corresponding network tariffs to these retail tariffs.[38] This means:

- existing small business customers will be eligible to access the retail tariff if they accessed the corresponding obsolete retail tariff 62, 65 or 66[39] at some point between 1 July 2017 and 30 June 2020. 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.

Ergon Retail had concerns that adopting the network tariff arrangements would be inconsistent with Ergon Network's strategy to transition customers on obsolete tariffs towards greater cost reflectivity.[40] Given this, it recommended we restrict access to small customers accessing obsolete tariffs on 30 June 2021 and have a 12-month opt-in period for eligible customers.

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). This is also consistent with the specific requirements in the delegation and the Minister's expectations that these new tariffs be based on the corresponding AER-approved network tariffs and grandfathering arrangements.

[36] EQ, sub. 8, p. 5.
[37] EQ, sub. 8, pp. 5–6.
[38] See Appendix I for the tariff schedule and the detailed terms and conditions of these tariffs.
[39] The new retail tariffs that correspond with the obsolete tariffs will be tariffs 62A, 65A and 66A (respectively).
[40] EQ, sub. 8, p. 4.

We have not incorporated Ergon Retail's recommended alterations to the grandfathering arrangements, which would ultimately impose more stringent conditions than those at the network level. This would mean deviating from the network requirements and, in this instance, it is unclear why these tariffs should be made available to customers at the network level, but not at the retail level on the same basis. We are also not convinced our approach is inconsistent with Ergon Network's strategy, as Ergon Retail suggested. We are incorporating the arrangements Ergon Network put forward to the AER (which were subsequently approved)—we assume Ergon Network would propose arrangements consistent with its internal strategy and transition pathway for these customers.

Customers will only be able to opt in to these tariffs once—that is, if customers opt in to these tariffs and then move to another tariff, they will not be able to access the new transitional tariffs again.

Customers eligible to access these tariffs should note these tariffs are transitional in nature. 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 Network's TSS). However, whether they extend beyond this will depend on the arrangements Ergon Network proposes, and the AER approves, for the next regulatory control period (2025–30).

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

Information and timing

We are mindful stakeholders would have preferred further detail on the new transitional retail tariffs sooner. Customers raised concerns throughout the review on the level of information available and said we should provide detail on the likely bill impacts for small and large customers moving from the existing obsolete tariffs.[41]

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

- Ergon Network's TSS[42], 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
- Ergon Network's 2021–22 pricing proposal to the AER, which was approved on 14 May 2021.[43]

We do not have the necessary customer information to assess and provide the detailed bill impact assessments stakeholders requested. This would need to be developed with the assistance of Ergon Retail (using relevant customer consumption data) and using the final notified prices set out in this report. Further, even if we could present bill impacts, it would be at an aggregate level and based on average consumption (like our other bill impact charts), which would not likely satisfy customers' desire for further details tailored to their circumstances.

We strongly recommend customers engage directly with Ergon Retail, in addition to the engagement it has reported to have made with customers to date. Ergon Retail remains best

[41] QFF, sub. 1, pp. 2–3; Cotton Australia, sub. 5, pp. 2–4; Canegrowers, sub. 6, pp. 2–3.
[42] The AER published its final revenue and tariff determinations for Ergon Network on 5 June 2020. The AER subsequently approved Ergon Network's 2020–21 pricing proposal on 30 June 2020.
[43] The AER approved 2021–22 network tariffs for Energex and Ergon Network to apply from 1 July 2021.

placed to provide the more detailed assessments customers desire, including what alternative tariffs are available (as well as bill impacts) based on their individual circumstances.

To clarify, in response to QFF's comments, if customers on obsolete tariffs do not elect to move to an alternative tariff before their obsolete tariff expires, they will be transferred to an applicable tariff at the discretion of the retailer. As discussed in section 3.4.2, this discretion is contained in the tariff schedule to allow the retailer to assign the customer to the tariff that is suitable for the customer's individual circumstances. This, however, will not limit customers from electing to subsequently move to a different applicable tariff. However, we emphasise this circumstance will only occur if a customer fails to nominate a tariff themselves prior to the expiry of the obsolete tariff, and we again strongly recommend customers on obsolete tariffs to contact Ergon Retail for advice and information on the tariffs available to them.

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 Network's TSS:

- business customer (basic)>100 MWh per annum network tariff
- residential customer (basic)>100 MWh per annum network tariff.

We must consider only introducing a retail tariff based on the residential variant if there is a need for it at the retail level.[44] 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.[45] 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 Network'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).[46]

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 Network's annual pricing proposal for 2021–22.[47]

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.[48]

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[44] Appendix A: Minister's delegation, terms of reference, clause 2(d).
[45] Appendix A: Minister's delegation, terms of reference, clause 2(d).
[46] AER, *Ergon Energy Network determination*, *Attachment 18: tariff structure statement*, final decision, June 2020, pp. 25–26.
[47] Ergon Energy Network, *Ergon Energy Network Tariff Structure Statement 2020–25*, June 2020 (erratum: version 6, August 2020), pp. 27–28.
[48] EQ, sub. 3, p. 5, sub. 8, p. 3; Etrog, sub. 14, p. 4.

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.[49]

Analysis and final 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.

EQ supported introducing this tariff but said we should change the tariff number we assigned in our draft determination (tariff 43). This is because this number was previously assigned to a retail tariff that has since been made obsolete and this could cause customer confusion.[50]

We have decided to maintain our approach and number this tariff as tariff 43. The previous (obsolete) tariff 43 was discontinued in 2015 and was a demand tariff with a time-of-use charging component. Given the length of time since that tariff was discontinued and the fact that it had a different tariff structure than (the new) tariff 43, we consider that customer confusion with the previous discontinued tariff is likely to be low and can be managed by retailers.

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.[51] 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[52] or 200 MWh per annum.[53] CPAQ also requested that caravan parks operating embedded networks be excluded from large customer tariffs.[54]

We acknowledge several stakeholders raised concerns and said we should raise the large customer threshold as part of this price determination. However, as noted above, the threshold for determining a large customer is established in legislation and is not something we can change. As such, these concerns go beyond the scope of this determination—legislative requirements are set by the Queensland Government.

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[49] CPAQ, sub. 2, pp. 4–5.
[50] EQ, sub. 8, p. 3.
[51] See the *National Energy Retail Law (Queensland)*, ss. 5–6. The National Energy Retail Regulation (s. 7) establishes the upper consumption threshold at 100 MWh per annum, for determining whether business customers are small or large customers of electricity.
[52] Cotton Australia, sub. 5, p. 5, sub. 9, p. 2; QFF, sub. 7, pp. 4–5.
[53] Canegrowers, sub. 6, p. 1.
[54] CPAQ, sub. 2, pp. 4–5.

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.[55]

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 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.[56]

Stakeholders did not raise any concerns with this approach and supported cost-effective measures that assist users in their transition to ADM.[57]

Analysis and final position

Having regard to relevant factors, our determination 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.

Our final ADM charges reflect the AER's approved Energex metering costs for type 6 small customers.

The final ADM charges for small customers are set out in Chapter 6. For clarity, these charges do not include a further surcharge for manual meter reading (for type 4A meters), as type 6 metering service charges already include manual meter reading services.

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.[58]

[55] Appendix A: Minister's delegation, terms of reference, clause 2(j).
[56] Appendix A: Minister's delegation, cover letter, p. 2.
[57] Cotton Australia, sub. 5, p. 5; EQ, sub. 3, p. 5; Etrog, sub. 14, p. 4.
[58] Connection asset customers (CACs) and individually calculated customers (ICCs).

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)[59]
- 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.[60]

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'.[61] Further, 'while 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'.[62]

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 standalone 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.[63]

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.

[59] Appendix A: Minister's delegation, terms of reference, clause 2(p).
[60] Appendix A: Minister's delegation, terms of reference, clause 2(k).
[61] Appendix A: Minister's delegation, cover letter, p. 1.
[62] Appendix A: Minister's delegation, cover letter, p. 1.
[63] Queensland Government, *Gazette*, no. 72, 11 December 2020, p. 519.

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 (mentioned above).[64]

Based on subsequent information it provided, EQ 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.

Etrog supported making the tariff schedule simpler and more accessible for customers, but agreed the schedule needs to provide sufficient certainty about how tariffs are to be applied and made available to customers. It supported including network tariff requirements in the tariff schedule to ensure they apply at the retail level and increase transparency (including the specific eligibility criteria of the distributors). Customers then would not need to investigate distributors' requirements as well as consider the tariff schedule.

Etrog noted such an exercise is not straightforward, however, because changes by distributors to meet regulatory requirements is not something the QCA can fully control. As such, Etrog said a mechanism would be required so the distributor could only change their criteria at such time the retail tariff schedule can also be modified; otherwise, there will be a mismatch between two sets of requirements.[65]

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.

Analysis and final 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. Some stakeholders said the retail tariff schedule would benefit from more concise information (including simpler language)[66] 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. It is relevant that the tariff schedule currently:

- contains key network conditions relevant to stakeholders, including details on load control network tariff requirements[67]

[64] EQ, sub. 3, p. 5.
[65] Etrog, sub. 14, p. 5.
[66] Cotton Australia, sub. 5, p. 5.
[67] The schedule does not completely mirror or reproduce network tariff requirements and terminology.

- 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 that are 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, several new retail tariffs are being introduced as part of this determination, based on network tariffs whose terms and conditions have only recently been 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.

As noted by Etrog, there are difficulties associated with incorporating further substantial detail on network requirements into the tariff schedule, including those associated with ensuring consistency at all times between the tariff schedule and the most current network requirements. Etrog's suggestion of a mechanism to flow through changes would be desirable; however, we do not have the ability to control the timing of changes to a distributor's regulatory framework, and our role in setting notified prices is subject to delegation from the Minister.

Accordingly, we consider the tariff schedule is as standalone as practicable at this time and contains sufficient detail and information for customers.

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[68] 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.[69]

Analysis and final 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.

[68] 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.
[69] Appendix A: Minister's delegation, terms of reference, clause 2(i).

Tariff 33 retailer discretion

Our final 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 Retail to work with customers and move them to a tariff appropriate for their individual needs.[70]

Etrog said this transition period is preferable to immediately removing this tariff option, but it is inappropriate for us to set a sunset date without knowing how many customers will be affected, the characteristics of those customers, and why those customers are currently using this tariff option. It said this information should be presented to stakeholders for further consultation prior to deciding on this matter.[71]

We confirm EQ has confidentially advised us the number of customers on this tariff option, which is low (i.e. less than 50). We maintain our view it is appropriate to phase out this tariff option given it is not reflected at the network level. Further, stakeholders have not identified a need to maintain this tariff option for residential customers. We consider a 12-month sunset date is reasonable and will provide sufficient time for existing customers to transition to an alternative tariff arrangement.

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.[72] We note 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[73], given we introduced a specific primary load control tariff for small business customers.

Other discretions

Our 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 final 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.[74]	EQ supported the removal of this discretion and stated its preference is for CACs and ICCs to be on tariffs that have been developed specifically for these customer types.[75] 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

[70] EQ, sub. 3, p. 9, sub. 8, p. 6.
[71] Etrog, sub. 14, p. 6.
[72] Cotton Australia, sub. 5, p. 5.
[73] QCA, *Supplementary review: regulated retail electricity prices 2020–21*, final determination, October 2020, p. 13.
[74] Queensland Government, *Gazette*, no. 72, 11 December 2020, p. 519.
[75] EQ, sub. 3, p. 6, sub. 8, p. 6.

Service provider discretion	Analysis and final position
	changes allowing them to select the most suitable tariff from any tariff class, noting the seasonal variations in electricity use for cotton ginning.[76] 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, we removed this retailer discretion. Customers should use the tariffs reflecting 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.[77]	We removed this entire provision from the tariff schedule, given the scheme expires on 30 June 2021, which is before this price determination period starts (i.e. 1 July 2021). We note EQ supported this provision being removed.[78]
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.[79]	This discretion has been retained. We consider it is necessary for the proper functioning of tariff arrangements.[80] Without 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. This discretion 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. EQ supported retaining this discretion.[81]
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.[82] Such equipment must be installed at the customer's expense	We removed this discretion. Whether or not a metering service provider agrees to bear this cost for a customer is a matter between those parties and it is unclear this discretion is necessary in the retail tariff schedule. We note EQ supported removing this discretion.[84]

[76] Cotton Australia sub. 5, pp. 5–6.
[77] Queensland Government, *Gazette*, no. 72, 11 December 2020, p. 519.
[78] EQ, sub. 8, p. 6.
[79] Queensland Government, *Gazette*, no. 72, 11 December 2020, p. 520.
[80] While this discretion has been retained in the tariff schedule, it has been relocated due to other amendments made to the tariff schedule–see Appendix I.
[81] EQ, sub. 8, p. 6.
[82] Queensland Electricity Connection and Metering Manual.
[84] EQ, sub. 8, p. 6.

Service provider discretion	*Analysis and final position*
unless otherwise agreed with the metering service provider.[83]	
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.[85]	These discretions have been retained. 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. EQ supported retaining these conditions to make it explicitly clear to customers that timeframes of supply will vary subject to the distribution entity's discretion.[86]
Tariff 33 … Times when supply is available is subject to variation at the absolute discretion of the distribution entity.[87]	
Tariffs 34, 60A and 60B Times when supply is available is subject to variation at the absolute discretion of the distribution entity.[88]	
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.[89]	We removed the discretion for the retailer to agree to an exception to these arrangements, as it is not reflected in the network tariff requirements. We also made changes to the eligibility criteria for these tariffs to better align with the network tariff requirements. We consider this is appropriate and will improve clarity and the stand-alone nature of the tariff schedule. EQ supported these changes.[90]
Tariff 91 It is available only to customers with small loads other than streetlights as approved by the retailer, and applies where:	EQ supported retaining this discretion. It said the unmetered supply network tariff will be determined at the time of connection by the distribution entity.[92] We understand the distribution entity has a role in approving these types of connections. We have replaced the

[83] Queensland Government, *Gazette*, no. 72, 11 December 2020, p. 520.
[85] Queensland Government, *Gazette*, no. 72, 11 December 2020, pp. 520–521.
[86] EQ, sub. 3, p. 8; sub. 8, p. 7.
[87] Queensland Government, *Gazette*, no. 72, 11 December 2020, p. 521.
[88] Queensland Government, *Gazette*, no. 72, 11 December 2020, p. 521.
[89] Queensland Government, *Gazette*, no. 72, 11 December 2020, p. 521.
[90] EQ, sub. 8, p. 7.
[92] EQ, sub. 3, p. 10, sub. 8, p. 7.

Service provider discretion	***Analysis and final 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.[91]	retailer's discretion by instead referring to the distribution entity's approved unmetered supply devices list (or equivalent document).[93]
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.[94]	EQ supported removing this condition.[95] Cotton Australia said 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.[96] Similarly, CPAQ said 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.[97] We removed 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.[98]	EQ supported removing this condition and said this was no longer an issue given the standard asset customer (SAC)/CAC/ICC designations.[99] Given our decision to introduce a 12 month sunset date for the voltage discount arrangements (see below), we have retained this discretion at this time. The continuing need for this discretion could be considered in a future determination.
Meter wiring and equipment to house meters is the customer's responsibility and must be installed and maintained at the customer's expense unless otherwise agreed with the metering service provider.[100]	We removed this discretion. Whether or not a metering service provider agrees to bear this cost for a customer is a matter between those parties, and it is unclear this discretion is necessary in the retail tariff schedule. EQ supported removing this discretion.[101]

[91] Queensland Government, *Gazette*, no. 72, 11 December 2020, p. 521.
[93] For example, see Ergon Energy Network, *Approved unmetered supply devices*, December 2017.
[94] Queensland Government, *Gazette*, no. 72, 11 December 2020, p. 522.
[95] EQ, sub. 3, p. 10; sub. 8, p. 8.
[96] Cotton Australia, sub. 5, pp. 5–6.
[97] CPAQ, sub. 2, p. 5.
[98] Queensland Government, *Gazette*, no. 72, 11 December 2020, p. 522.
[99] EQ, sub. 3, p. 10, sub. 8, p. 8.
[100] Queensland Government, *Gazette*, no. 72, 11 December 2020, p. 522.
[101] EQ, sub. 8, p. 8.

Service provider discretion	*Analysis and final position*
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.[102]	We maintained these discretions, noting the unique circumstances of arrangements for card-operated meters. We also understand EQ is the only party permitted to provide card operated meters in Queensland. We sought further information from stakeholders about whether it is necessary for the distribution entity to continue to be involved in these decisions. EQ advised that because isolated networks are non-Power of Choice communities, the distribution entity is the meter provider—therefore, it needs to continue to be involved in these arrangements.[103]

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.[104]

Stakeholder comments

EQ supported 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.[105]

Based on subsequent information provided by EQ, we understand 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 Network, 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.

[102] Queensland Government, *Gazette*, no. 72, 11 December 2020, p. 522.
[103] EQ, sub. 8, p. 8.
[104] Queensland Government, *Gazette*, no. 72, 11 December 2020, p. 522.
[105] EQ, sub. 3, p. 11.

Analysis and final position

On the information available, our final position is to remove the voltage discount provision from the retail tariff schedule and set a sunset date of 12 months for affected customers to transition from these arrangements and consider alternative tariff options.

Given the rebate is not reflected at the network level, it is not appropriate for it to be retained at the retail level. Based on EQ's comments, it appears these rebates are a legacy arrangement that may not have been reflected at the distribution level for some time.

Because customers receiving the rebate may need time to assess the bill impacts and suitable tariff options, we have provided customers with a sunset period of 12 months so that they can undertake this assessment.

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.[106]

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

- 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.[107]

Analysis and final 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. We note EQ supported aligning these definitions and threshold amounts to ensure consistency and reduce the potential for confusion.[108] As such, we have updated the tariff schedule to reflect network tariff thresholds.

However, we have retained language from the current retail tariff schedule (use of 'generally' in connection with the thresholds), which provides some flexibility, so that these thresholds do not need to be strictly met in all instances. This will allow, for example, legacy connections to be maintained at their existing customer class where appropriate. This is reflective of network

[106] Queensland Government, *Gazette*, no. 72, 11 December 2020, p. 519.
[107] See Ergon Energy, *Ergon Energy Tariff Structure Statement 2020–25*, June 2020 (Erratum: version 6, August 2020, p. 16).
[108] EQ, sub. 8, p. 8, sub. 3, p. 11.

arrangements, which acknowledge some existing customers will continue to be allocated to the ICC tariff class for legacy reasons.[109]

Tariff 22B structure

Ergon Retail considered that tariff 22B (small business time-of-use inclining band primary tariff) is overly complicated for the purpose it serves. It recommended that this tariff structure be simplified by removing bands 2 to 5 for the daily supply charge. It said this would make this tariff more attractive to customers and assist them with determining the benefits of a time-of-use tariff structure.[110]

We acknowledge the views of Ergon Retail on this matter. However, the structure of tariff 22B is based on the corresponding network tariff. This is consistent with the N+R approach we have applied in this determination. It is also consistent with the Minister's delegation to consider maintaining existing standard retail tariffs. As such, we have decided not to amend the structure of this retail tariff in the manner suggested by Ergon Retail.

Tariff combination restrictions for tariffs 62A, 65A and 66A

Consistent with network tariff requirements, we have made the business flat rate tariff (tariff 20) not available in conjunction with any other primary business tariff.[111]

This restriction will apply to customers seeking to access the new tariffs 62A, 65A and 66A, which means these tariffs will not be available in conjunction with tariff 20. On that basis, we have removed the specific restrictions we proposed in our draft determination that would prevent these tariffs from being available in conjunction with any other primary tariff. This approach for tariffs 62A, 65A and 66A is consistent with the approach taken at the network-level for the underlying network tariffs.

Consistency of tariff 62A with tariff 62

EQ said tariff 62A should apply in the same manner as the expiring tariff 62. It sought clarification that usage blocks 1 and 2 are based on average daily load.[112] We have not made any changes to the tariff structure of tariff 62A relative to tariff 62. Consistent with the N+R framework, we have based the tariff structure of tariff 62A on the underlying network tariff, which in turn has been based on the existing tariff 62.

Charging for alternative control services

We have included an amendment in the retail tariff schedule to recognise that the prices retailers may charge for distribution entity alternative control services, which the AER regulates, may be modified by energy law.[113] This is a clarifying amendment that reflects the operation of existing energy law arrangements.

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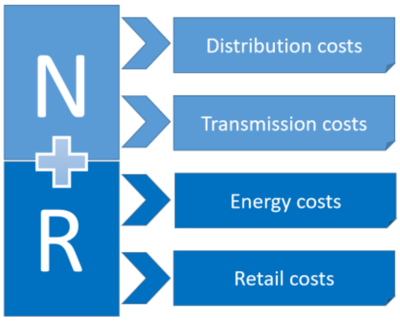
[109] See Ergon Energy, *Ergon Energy Tariff Structure Statement 2020–25*, June 2020 (Erratum: version 6, August 2020), p. 16.
[110] EQ, sub. 8, p. 16.
[111] Similarly, we have made the residential flat rate tariff (tariff 11) not available in conjunction with any other primary residential tariff, which is also consistent with network tariff requirements.
[112] EQ, sub. 8, p. 3.
[113] Schedule 8 of the Electricity Regulation 2006 (Qld) sets out the maximum prices that customers can be required to pay for certain services related to the supply of electricity. These services overlap with the alternative control services that the AER regulates.

4 INDIVIDUAL COST COMPONENTS

This chapter considers 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).

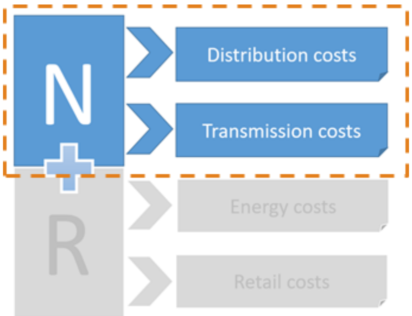
The cost components we discuss here are:



- 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,[114] all of which are regulated (and approved) by the AER.



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

- increase by up to 1.1 per cent for most small customers and decrease by 1 per cent for customers on tariff 22A
- increase by 2.4 to 4.9 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 set the N component by:

- For residential and small business customers on:
  - flat and secondary load control tariffs—basing the N component 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—using 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—basing the N component on the price level of the relevant Energex charges but utilising Ergon Network tariff structures.

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

- For large customer retail tariffs—basing the N component on the relevant prices for Ergon Network's east zone, transmission region one.[115]

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

- For the three new transitional retail tariffs—basing the N component on the relevant prices for Ergon Network's east zone, transmission region one.
- For the new large customer retail tariff based on the 'Business customer (Basic)>100 MWh pa' network tariff—basing the N component on the relevant prices for Ergon Network'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'[116] network tariff—basing the N component on the price level of the relevant Energex charges but utilise Ergon Network tariff structures.

The delegation is broadly consistent with previous years and the way in which we 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.[117]
- EQ said 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.

In addition, stakeholders said there is no transparency around the Solar Bonus Scheme (SBS) costs included in electricity prices this year[118] and ultimately these costs should be removed from network costs and paid for by the Queensland Government (not electricity users).[119] Canegrowers said we should clearly identify the costs to the Queensland economy that flow from the switching of the solar bonus payment from consolidated revenue to electricity prices.[120]

4.1.3 Analysis and final position

We have set the N component for existing tariffs (both small and large customers) and new tariffs having regard to the relevant factors, stakeholder comments and our own analysis. On this basis, we 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 pricing region)

[115] The Ergon Distribution pricing region with the lowest cost of supply that is connected to the NEM.
[116] 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.
[117] Canegrowers, sub. 6, attachment p. 2.
[118] Canegrowers, sub. 11, p. 3.
[119] QEUN, sub. 12, pp. 12, 14–15, 22–24; QFF, sub. 7, p. 3; Cotton Australia, sub. 9, p. 2.
[120] Canegrowers, sub. 11, p. 3.

  - for large customers, basing the costs of supply on east zone, transmission region one (Ergon Network's lowest-cost region that is connected to the NEM)
- for retail tariffs with no underlying network tariff (tariffs 12A, 14, 22A and 24)—using a price indexation methodology, specifically an 'X-factor' approach[121], which will allow for the pass-through of AER-approved changes in network costs to customers on these retail tariffs[122]
- 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 Network's lowest-cost region that is connected to the NEM).[123]

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).

We are mindful customers would prefer the SBS charges not to be included in notified prices and would like these charges itemised in the notified price build-up. Similar concerns were raised by stakeholders in last year's price determination.

However, it remains the case that jurisdictional scheme charges (including SBS charges) are included in the AER–approved network prices, which in turn form the basis of the network component in notified prices. As such, SBS costs are legitimate costs EQ is entitled to recover through its network prices under the National Electricity Law (which provides for distributors to recover jurisdictional costs, including SBS costs, through network charges). Also, as the SBS charges are also included in the total AER-approved network prices, it is not necessary for us to separately include (or itemise) these costs for the purpose of setting the N component for notified prices.

Overall, the network costs included in notified prices this year have increased for most small and large customer tariffs (Figures 4.1 and 4.2).

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 some small customer 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.

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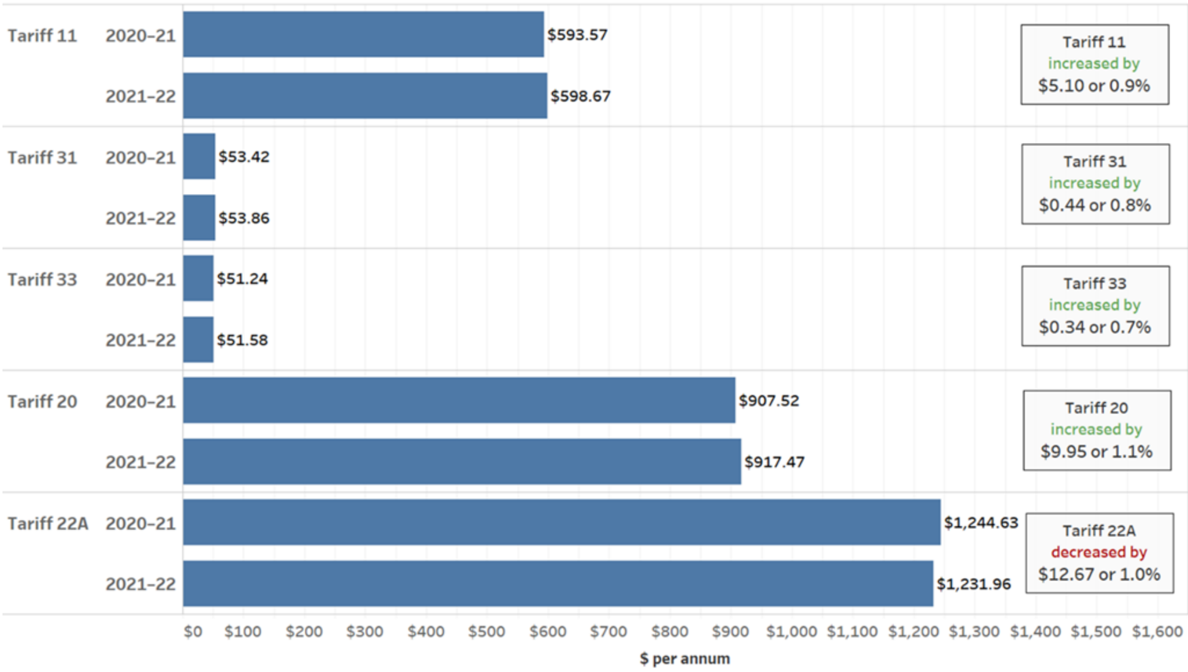
[121] As part of the revenue determination process, the AER produces five X-factors for the purposes of revenue smoothing (the X-factor for the first year is also known as P_0). Mathematically, X-factors are weights that are applied to allowable revenue for one year to calculate the allowable revenue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

[122] 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.

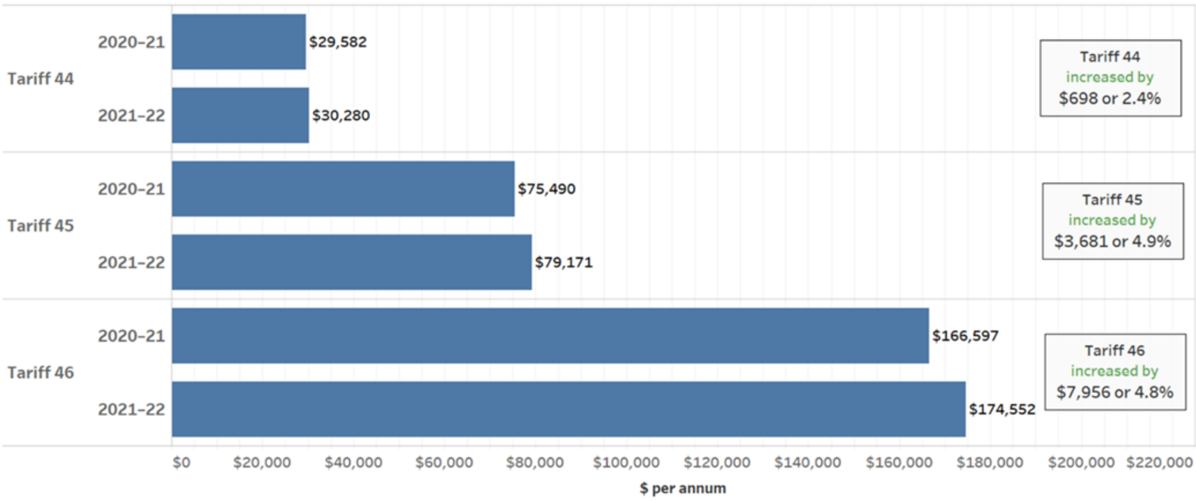
[123] The N component for the new residential tariff is not discussed, given this tariff is not being introduced in this price review (see section 3.3).

Figure 4.1 Network costs—typical customers on small customer tariffs (incl. GST)



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

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



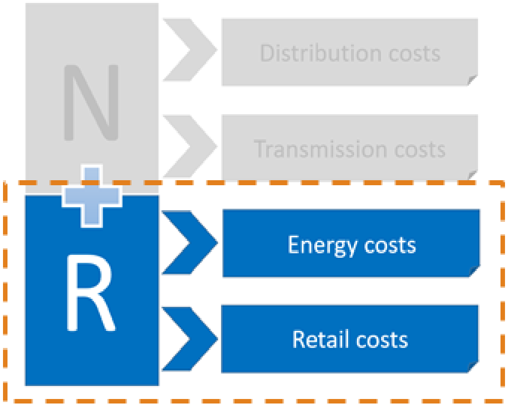
Note: Amounts are rounded to the closest dollar. Therefore, amounts may not add precisely. Percentage changes are based on unrounded amounts.

Timing and updates

The draft network prices provided to us by Ergon Network and Energex (used in our draft determination) have been updated in this report to reflect those approved by the AER in May 2021. This addresses some concerns stakeholders had on whether this would be possible given the timeframes of our review coinciding with the AER's annual price review.

The notified prices we have set therefore include the AER-approved network prices for 2021–22. As a result, for small customers there is no material change in notified prices, because the approved network prices are substantially unchanged from those used in our draft determination. For large customers, there are changes in notified prices, because the approved network prices have increased relative to those used in our draft determination. According to EQ, this is because the final network prices approved reflect updated customer uptake and energy consumption, as well as an increase in Powerlink's transmission charges.[124]

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.

Our approach to estimating energy costs this year is broadly the same as last year. Total energy costs are expected to decrease by 11.8 to 12.7 per cent for small customers (depending on the tariff) and by 11.7 per cent for large customers.

We updated the retail cost allowances for small customers based on recent market information but used the existing retail cost allowance for large and very large customers, adjusted by inflation.

Overall, total retail costs are expected to decrease by 21.7 to 40.7 per cent for residential customers, increase by 10.7 to 14.2 per cent for small business customers, and decrease by 1.4 to 2.4 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 (such as environmental and market participation costs) and energy losses. Consistent with previous years, we have engaged ACIL Allen to provide expert advice on energy costs.[125]

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 the reform's impact on the availability of ASX cap contracts and on 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[126]
- take into account the impacts of covid-19

[124] See Ergon Energy's pricing proposal for more information on the approved network prices, including for large customers (specifically discussed in section 5.1 of that report).
[125] ACIL Allen, *Estimated Energy Costs*, final report prepared for the QCA, May 2021.
[126] This refers to the practice of deriving a hedging strategy after the simulated spot prices are known.

- review the allowance for the costs associated with the NEM management fees.[127]

Canegrowers suggested that a separate wholesale energy cost should be estimated for irrigation activities to reflect the relevant network tariff structures.[128] The Queensland Electricity User Network (QEUN) stated that wholesale electricity prices should be capped at $60/MWh and noted the recent declining wholesale spot prices. It also compared wholesale prices with our energy cost estimates.[129]

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 determined 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 supply/costs), and then estimate wholesale energy costs for a retailer that hedges spot price risk (through exchange-traded energy derivatives, i.e. ASX energy futures[130])
- market data up until May 2021—to take into account the most current information (including developments over the potentially volatile summer period).[131]

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

Analysis and final position

Our final 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.

The approach uses the latest available market data—including information on the uptake of rooftop solar PV, renewable energy resource traces[132], 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 final determination timeframe.

[127] EQ, sub. 3, pp. 12–13; EQ, sub. 8, pp. 9–10.
[128] Canegrowers, sub. 6, p. 2; Canegrowers, sub. 11, p. 2.
[129] QEUN, sub. 12, pp. 27–29.
[130] 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.
[131] See Appendix C for a detailed description of ACIL Allen's market hedging approach.
[132] Renewable energy resource traces reflect the availability and quality of renewable resources/generation in different regions, depending on weather and geographical conditions.

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.[133]

A summary of our assessment is outlined below, including a discussion of the points that stakeholders raised. 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 specific to 2020–21.

We 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 no evidence to suggest that retailers are relying on other types of financial instruments (including base and super peak contracts[134]) as a replacement for the cap contracts.

In March 2021, ASX Energy introduced new cap contracts[135] (designed for a five-minute settlement) to replace the existing cap contracts. We investigated the viability of using the data from the newly listed contracts to estimate wholesale energy costs. We concluded that such an approach is appropriate on the basis that there is a reasonable level of trading in the newly listed cap contracts. The level of trades of these new contracts (since they have been available) is comparable to the level of trades for the existing cap contracts for the same duration (in the July to September 2021 quarter). In the absence of more reliable information, we consider data from the new cap contracts to be the best indicator of the costs that retailers are likely to face when hedging with cap contracts.

This approach is also consistent with EQ's view that the actual traded price of cap contracts would be a better guide in estimating the costs that retailers will incur.[136] The AER adopted the same approach when determining the wholesale energy costs for its 2021–22 default market offer.

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 May 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

[133] The appropriateness of a market hedging approach is discussed further in Appendix C and ACIL Allen's final report on energy costs.
[134] 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).
[135] The new cap contract is known as the Australian Base Load 5 Minute Cap Futures Contract.
[136] EQ, sub. 8, pp. 9–10.

latest demand forecasts, which include the projected impacts of covid-19[137], to estimate wholesale energy costs.

We 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.

Canegrowers also said that the type of meters that customers hold have no impact on how retailers incur costs when purchasing electricity from the NEM.[138] However, this view is inconsistent with how the NEM is operated. To allow for settlement within the NEM (with different spot prices and volumes for settlement every half-hour), AEMO uses the NSLPs to approximate the amount of electricity consumed by customers on accumulation meters in a region. In other words, the average wholesale spot prices that retailers pay for customers on accumulation meters are determined by using the NSLPs.

We note QEUN's preference that wholesale electricity prices should be capped at $60/MWh, but we do not consider an arbitrary cap appropriate for the task at hand. It would introduce risks of understating the costs of supply, as energy costs fluctuate due to market conditions. It would also mean setting notified prices that are inconsistent with the Queensland Government's UTP, which requires prices for small customers to be based on the cost of supply in SEQ (where wholesale electricity prices are not capped).

QEUN also compared wholesale prices with our energy cost estimates. However, wholesale prices do not reflect the costs retailers incur in practice when sourcing electricity from the NEM. To manage spot price volatility risk, retailers generally lock in the price for an amount of electricity that they will pay for in the future (e.g. hedging through the purchase of ASX contracts). This means that, in addition to wholesale prices, a retailer's hedging strategy plays a crucial role in determining the actual costs the retailer incurs when purchasing electricity from the NEM.

Compared to the estimates from last year, our estimates of wholesale energy costs have fallen for both small and large customer tariff classes[139]—primarily reflecting the expected continued entry of a large amount of renewable generation into Queensland and other NEM regions and prevailing lower domestic gas prices to date.[140]

[137] AEMO, *2020 Electricity Statement of Opportunities*, August 2020.
[138] Canegrowers, sub. 11, p. 2
[139] As discussed in Chapter 3, our 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.
[140] 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[141] 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[142]
- NEM management fees and ancillary services charges— fees levied by 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) charges—fees levied by AEMO to cover the costs of maintaining power system reliability and security using reserve contracts. The RERT 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).

[141] 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 final report on energy costs.

[142] 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 final position

Our 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 charges	• RERT 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 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.[143]

EQ said we should review the allowance for NEM management fees. It queried the exclusion of the National Transmission Planner (NTP) related costs from these fees. In response we note:

- the costs related to the NTP are excluded because the recovery of these costs has been transferred recently to the transmission network service providers, forming part of the transmission use of system charges
- using AEMO's latest budget and projected fees (to estimate NEM fees) is appropriate, as these fees are levied by AEMO and reflect how retailers are likely to incur these costs in practice.

Compared to the estimates from last year:

- LRET costs have decreased by approximately 14 per cent ($0.70/MWh)—driven by a fall in the forward price of large-scale generation certificates due to an increase in renewable investment

[143] The appropriateness of these approaches is discussed further in Appendix C and ACIL Allen's final report on energy costs.

- SRES costs have increased by about 24 per cent ($2.21/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
- ancillary services charges have decreased by approximately 73 per cent ($1.12/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 5 per cent ($0.08/MWh) for small customer tariffs and by about 5 per cent ($0.07/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 estimate of other energy costs:

- for small customer retail tariffs increased by 0.5 per cent ($0.09/MWh)
- for large customer retail tariffs increased by 0.6 per cent ($0.10/MWh).

As part of this final determination, we have also updated our estimate of energy losses, based on AEMO's recently published 2021–22 loss factors. Compared to estimates for last year, overall energy loss factors[144] have:

- increased for small customer tariffs, reflecting an increase in distribution loss factors
- increased for large customer tariffs, reflecting an increase in transmission loss factors.

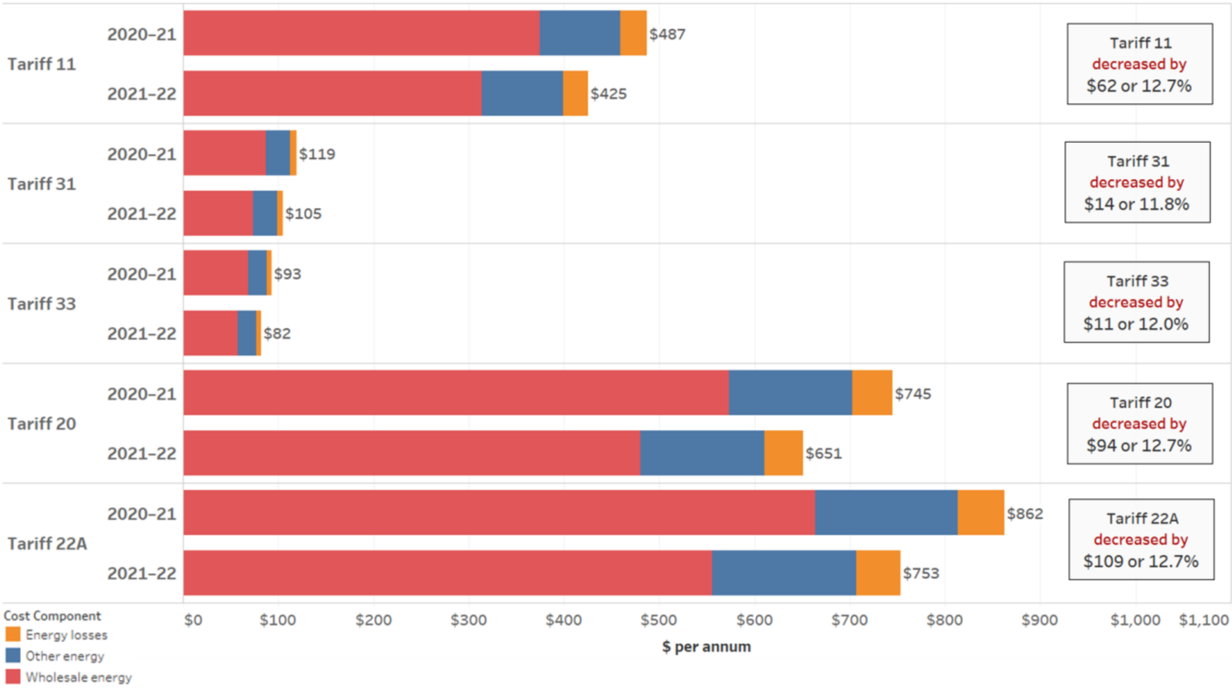
For a more detailed explanation of our considerations and ACIL Allen's approach, refer to Appendix C and ACIL Allen's final report.

Total energy costs included in notified prices

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

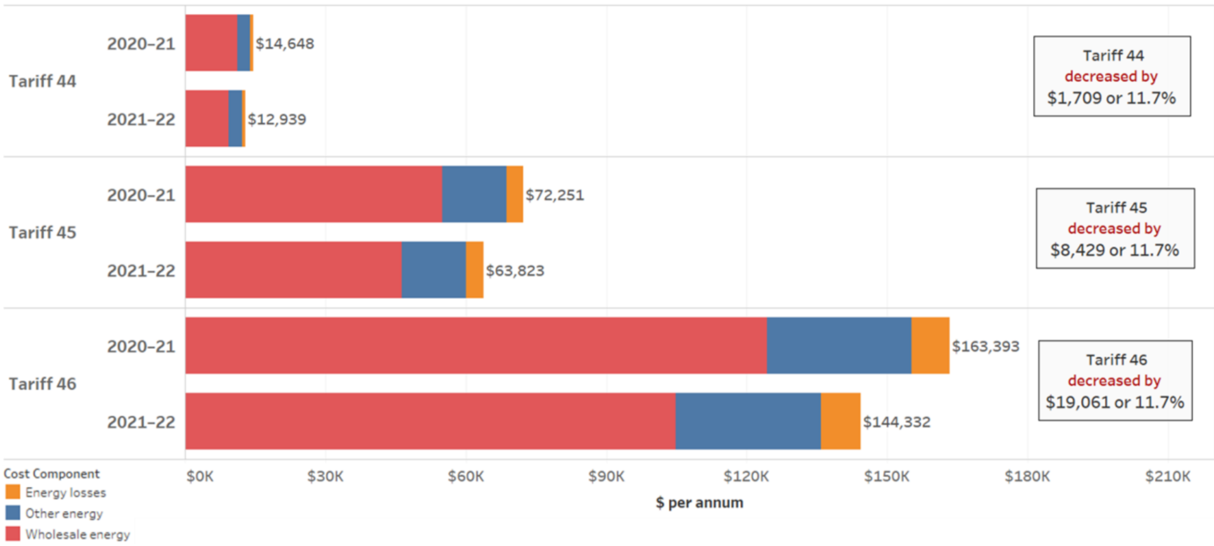
[144] Total energy loss factors are the product of the distribution loss factor and the transmission loss factor.

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



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

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



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 have undertaken a more fulsome review of all retail costs, which include the retail operating costs and retail margin, as part of this price determination.[145]

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.[146] Stakeholders expressed a desire in recent years for retail costs to be reviewed and updated estimates to be used to set notified prices.

This year, we updated the retail cost allowances using a benchmark approach similar to the approach we 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.

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 interim consultation paper for stakeholders to comment on.[147]

Stakeholder submissions

Canegrowers said the proposed methodology for estimating the retail component needed to be modified to avoid including non-existent costs, such as competition costs and any excess retailer margins arising from the continuing exercise of retail market power.[148] Similarly, QEUN said that customers in regional Queensland should not be paying for customer acquisition and retention costs SEQ retailers incur that are not incurred by Ergon Retail.[149]

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 mean that under the proposed approach, the retail costs would be artificially lowered well beyond their real value.[150] EQ also said that:

- the retail cost allowances should include costs associated with various regulatory and policy reforms [151]
- using 2020–21 market data is of significant concern, given covid-19 and government stimulus packages have skewed certain customer metrics that are key inputs in setting retail costs[152]
- a productivity factor should not be applied to the retail cost allowances given the current economic climate and ongoing regulatory reforms[153]

[145] 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.
[146] This approach has been used since the 2017–18 price determinations.
[147] ACIL Allen, *Updating retail costs for the 2021–22 regulated electricity price review – methodology document*, report prepared for the QCA, 2020.
[148] Canegrowers, sub. 6, p. 2.
[149] QEUN, sub. 12, p. 33.
[150] EQ, sub. 3, pp. 13–14.
[151] EQ, sub. 3, pp. 14–15, sub. 8, p. 14.
[152] EQ, sub. 3, pp. 14–15, sub. 8, p. 12.
[153] EQ, sub. 3, p. 15.

- payment fees should be netted out of the retail costs and incorporated into the gazette as standalone fees.[154]

Regarding the retail cost allowances for large customers, EQ supported us maintaining our current approach of using the established benchmark adjusted for inflation.[155]

Analysis and final position

We considered there was 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 have:

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

Small customers

As a result of our review, we updated the retail cost allowances for small customers based on the outcomes of ACIL Allen's benchmarking analysis. We undertook a benchmarking exercise similar to the approach used to establish retail cost allowances for small customers for 2016–17.[156] We consider this is a robust and transparent approach, as it relies heavily on outcomes observed in competitive retail markets.

To update retail cost estimates for small customers, ACIL Allen used retail market tariffs that were offered for 2020–21 in SEQ. The retail cost estimates 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 final report[157], which is 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 3). Given this, the 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.[158] We also note that SEQ has the highest level of satisfaction with competition in Australia.[159]

We considered EQ's comments that it was more appropriate for us to use standing offers of Tier 1 retailers operating in SEQ as the basis for estimating retail cost allowances, given the notified prices we set are used by retailers as their standing offer prices.[160] However, we are of the view

[154] EQ, sub. 8, p. 14.
[155] EQ, sub. 8, p. 10.
[156] In the 2016–17 final determination, we used a benchmarking approach to establish retail costs, with a bottom-up assessment to test the reasonableness of the benchmark market observations. This is in line with the AEMC's best practice retail price methodology outlined in its 2013 report. See AEMC, *Advice on best practice retail price methodology*, final report, 27 September 2013. This year, we have updated the benchmarked retail cost allowances set in 2016–17 to reflect more recent market data.
[157] ACIL Allen, *2021–22 regulated electricity price review – Updating retail costs*, final report prepared for the QCA, May 2021.
[158] This is discussed in further detail in ACIL Allen's final report on retail costs, chapter 2.1.
[159] Energy Consumers Australia, *Energy Consumer Sentiment Survey*, December 2020, p. 18.
[160] EQ, sub. 8, p. 11.

that it is more appropriate to use market offers to calculate the retail cost allowances, given that under our pricing framework, we separately account for the additional value standard contracts provide compared to market contracts in notified prices (see the standing offer adjustment discussed in section 5.1). Using market offers also better reflects the costs to supply small customers in SEQ, in line with the UTP.

Consistent with our previous practice, we do not consider it appropriate to remove competition-related costs (including customer acquisition and retention costs) from the estimates used to calculate the retail cost allowances. While stakeholders said that competition-related costs should be excluded from the estimates of the retail component, removing any costs 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 and remote Queensland is not appropriate.[161] 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[162], rather than a simple average (as in the 2016–17 determination). 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.[163]

While we considered EQ's concerns around using 2020–21 market data, we remain satisfied that using this more recent data is appropriate and most representative of current market conditions. We will consider whether it is appropriate to revisit our approach in future if we are 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. 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.

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[164] 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. There was also a lack of appropriate consumption data for the time-of-use and demand tariffs.[165] We consider it 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.

[161] EQ, sub. 3, p. 13, sub. 8, p. 11.
[162] Market share in this context refers to the number of customers served by each retailer.
[163] EQ, sub. 3, pp. 13–14.
[164] These tariff structures were introduced on 1 July 2020.
[165] This is discussed in further detail in Appendix D and ACIL Allen's final report on retail costs, chapter 4.3.

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 whether it was necessary to make any adjustments for these developments.

As the retail costs are estimated using 2020–21 market offers, an adjustment would only be necessary where developments in 2021–22 are likely to result in a material change in costs relative to those incurred in 2020–21.[166]

Overall, there was no conclusive evidence to suggest that any adjustments are required for covid-19, regulatory reform or productivity improvements.[167]

Impacts of covid-19

We do not consider the costs associated with covid-19 are likely to materially increase in 2021–22. In particular, we note:

- The RBA's May 2021 Statement on Monetary Policy forecasted a stronger improvement in economic activity in 2021–22 relative to 2020–21 than its November 2020 Statement on Monetary Policy (i.e. an improvement in GDP growth from 4 to 5 per cent). It also noted that the Australian economy is transitioning from recovery to expansion phase earlier and with greater momentum than initially anticipated.[168]
- The provisioning for bad debts by the three largest retailers—AGL, Origin Energy and Energy Australia—indicates that there does not appear to be any change in bad debts from 2020–21 to 2021–22.[169]

We consider that these improving economic conditions will likely put downward pressure on the level of debt and provisions for bad debt, such that retail costs will not be materially impacted in 2021–22.[170] On this basis, we consider the costs associated with covid-19 are likely to already be implicitly included in the retail cost estimates (through the use of 2020–21 market data).

We do not consider that historical evidence of increases in retail costs due to covid-19 is a reason to expect of a further increase in 2021–22 and does not demonstrate the need for an adjustment.[171] Further, evidence of allowances for covid-19 by other regulators will only be relevant where they have been made to allow for movements in costs from 2020–21 to 2021–22.[172] Accordingly, we do not consider any adjustment to account for the impact of covid-19 is warranted.

This conclusion is broadly consistent with the AER's approach in its final determination on the DMO for 2021–22. The AER considered that bad debt cost increases due to covid-19 would not be sufficiently material to warrant an adjustment to the DMO.[173]

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[166] ACIL Allen's final report on retail costs, chapter 5.2.2.

[167] 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—29 March 2021*, viewed 28 April 2021.

[168] RBA, *Statement on Monetary Policy*, May 2021.

[169] ACIL Allen's final report on retail costs, chapter 5.2.2.

[170] EQ, sub. 8, pp. 12–13.

[171] EQ, sub. 8, p. 12. Specifically, we note that the 6.68 per cent increase in retail costs calculated by the ACT's Independent Competition and Regulatory Commission relates to a change in costs from 2019–20 to 2020–21. Additionally, this increase in costs can primarily be attributed to an increase in smart meter costs.

[172] EQ, sub. 8, p. 12.

[173] AER, *Default Market Offer Prices 2021–22*, final determination, April 2021.

Regulatory reform

We have assessed the array of regulatory reforms identified[174] but do not consider it appropriate to make an adjustment at this time.

Of the regulatory reforms identified, a number of these are unlikely to result in increased incremental costs in 2021–22, compared to 2020–21. In particular:

- the majority of costs for the five-minute settlement reform and wholesale demand response mechanism would have been incurred before 2021–22 (given implementation is due to occur in October 2021[175])
- the costs of the global settlement reform are expected to be marginal and are likely to be outweighed by the benefits that arise[176]
- the Power of Choice reforms were implemented in 2017, and as such, any ongoing costs are unlikely to be incrementally higher than those costs incurred in 2020–21.

It is challenging to accurately quantify how reforms yet to be implemented will affect retailers' costs in 2021–22. For example, the AEMC noted that the costs associated with the bill contents and billing requirements rule change would be difficult to quantify and would be dependent on the nature of the required changes.[177] EQ also noted the costs associated with the Consumer Data Right[178] cannot be accurately forecast, because the rules and data requirements associated with the changes are currently unknown.[179] Any estimates based on the limited information currently available would be speculative and likely to be inaccurate.

For these reasons, we consider an adjustment is not warranted, and any quantifiable regulatory costs are likely to already be implicitly included in the retail cost estimates (by using 2020–21 market data).

Productivity improvements

We are of the view that there is insufficient evidence to justify an adjustment for productivity improvements. There is limited publicly available information on this topic, and the information that is available (such as the cost to serve data published by AGL and Origin Energy and the retail operating costs reported by the ACCC) show both upward and downward fluctuations over the reported periods.[180]

Based on this small sample of information and the absence of a downward trend in these retail costs, we do not consider that an adjustment for productivity improvements is warranted.

[174] EQ, sub. 3, pp. 14–15; EQ, sub. 8, p. 13.

[175] This is consistent with the AER's conclusion on the costs associated with the five-minute settlement reforms. See AER, *Default Market Offer Prices 2021–22*, final determination, April 2021.

[176] AEMC, *National Electricity Amendment (Global Settlement and Market Reconciliation) Rule 2018*, final rule determination, 6 December 2018, p. iii.

[177] AEMC, *Bill contents and billing requirements*, final rule determination, 18 March 2021, pp. 19, 35–37. This final rule determination requires retailers to comply with an AER mandatory billing guideline. The AER will publish the first billing guideline by 1 April 2022 and retailers will be required to comply with the billing guideline from 4 August 2022.

[178] The Consumer Data Right is a competition and consumer reform which will allow consumers to require a company such as their energy retailer to share their data with an accredited service provider such as a comparison site to get more tailored, competitive services. The ACCC released a consultation paper on 8 July 2020 and received submissions from a number of stakeholders in September 2020.

[179] Energy Queensland, submission to the ACCC, *Consumer Data Right Rules (energy)*, 28 August 2020, p. 23.

[180] See ACIL Allen's final report on retail costs, chapter 5.1.2.

Payment fees

EQ raised concerns with the treatment of credit card fees and annual membership fees in the benchmarking exercise. ACIL Allen provided further detail in its final report relating to the treatment of these fees as negative discounts. Sensitivity analysis showed that the assumptions made regarding the payment methods do not materially affect the results of the analysis.[181]

EQ also suggested that it would be more appropriate for these payment fees to be netted out of the retail costs and incorporated in the retail price gazette as standalone fees, to avoid over-recovery of these costs by retailers. We note that under section 22A of the National Energy Retail Law (NERL), retailers are restricted in the types of fees they can charge on standing offers. Credit card fees and annual membership fees are not included in the permitted fee types.[182] It is therefore not appropriate to include these fees in the gazette as suggested.

Our final position

Our final 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, draft report and final report.

Large customers

We considered establishing new allowances for large and very large customers but maintained our approach for these customers due to the data quality issues identified. That is, we have set 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.[183] 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 dataset as the basis for estimating the retail cost estimates for large and very large customers. The dataset was of varying quality and highlighted differences in the way retailers categorise costs.[184] EQ also expressed concern that the data it provided in relation to the 2020–21 financial year was largely a forecast rather than being reflective of actual costs incurred.[185]

We therefore consider that it is more appropriate to maintain our approach to updating the retail cost allowances for large and very large customers for this year's review. That 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

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[181] See ACIL Allen's final report on retail costs, chapter 3.1.2.
[182] QCA, *SEQ retail electricity market monitoring 2019–20*, market monitoring report, November 2020, p. 62.
[183] This data is commercially sensitive and cannot be reproduced in this report.
[184] Refer to Appendix D and ACIL Allen's final report on retail costs, chapter 6.
[185] EQ, sub. 3, p. 14.

these costs.[186] The approach also avoids the potential for cost biases resulting from relying on self-reported retail data.

On balance, we consider there is insufficient evidence to suggest that the retail cost allowances for large and very large business customers in 2021–22 will be materially different from those allowed in 2020–21. For large customer tariffs, we have adjusted the 2020–21 fixed retail cost allowances for inflation, and we 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 RBA in its Statement on Monetary Policy. 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.[187] Given the short-term volatility in the inflation for June 2021, we used the RBA's latest (June 2022) inflation forecast of 1.25 per cent.[188]

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

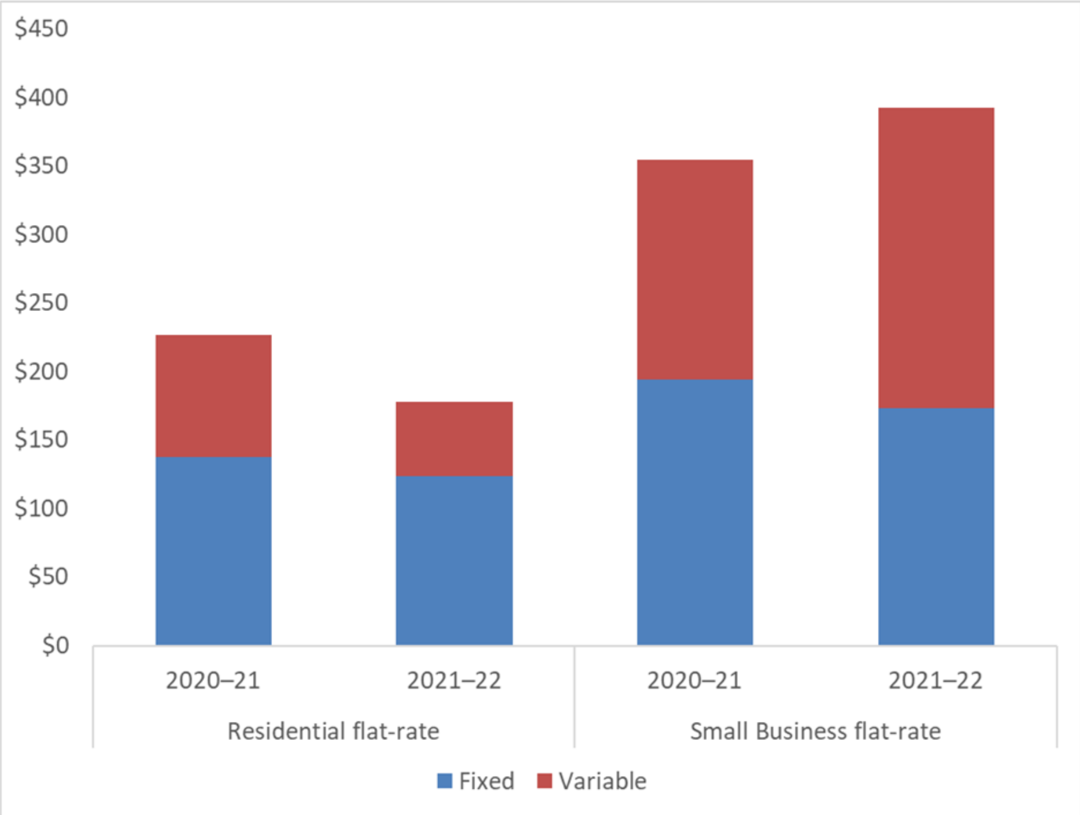
Retail cost allowances included in notified prices

For residential customers, retail costs are decreasing, 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.[189]

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

[186] Frontier Economics, *Retail Operating Costs*, report for the Economic Regulation Authority of Western Australia, March 2012, p. 6.
[187] P Lowe, 'The Year Ahead', address to the National Press Club of Australia, Canberra, 3 February 2021.
[188] RBA, Statement on Monetary Policy, May 2021.
[189] 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 (excl. GST)



Note: Retail cost allowances include regulatory fees.

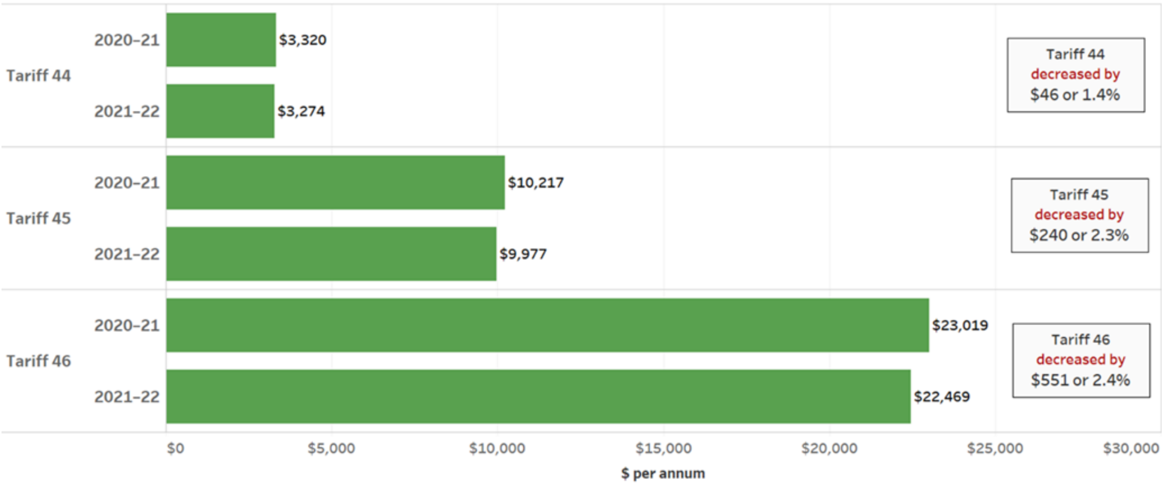
Source: QCA analysis, using data from ACIL Allen and Energy Queensland.

The following charts compare the retail cost allowances included in the notified prices with the 2020–21 allowances. The comparison is by tariff type for typical small and large customers.[190] Actual costs will vary for individual customers with different levels of electricity usage.

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

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

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



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

Application of 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 final position is to set the retail costs for the new tariffs using the same estimates (derived as part of this 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 adopted 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 applied 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 used 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.

5 OTHER COSTS AND PRICING ISSUES

This chapter sets out other costs and pricing issues, including any adjustments we have considered 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 we discuss here 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 to reflect the additional value and protections of terms and conditions contained in standard contracts
- maintaining the adjustment level previously applied (5 per cent of total costs), so long as the resulting electricity bill does not exceed the equivalent DMO reference bill—in which case we must also consider discounting the value of the adjustment in all tariffs, not only those with an equivalent DMO.

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

Stakeholder comments

Many stakeholders said electricity prices should not include a standing offer adjustment[191] and we should provide more information on how we quantify the benefits of standing offer contracts compared to market contracts.[192]

Etrog said we should make the calculations more transparent to ensure the fees and charges are not overstated, including by:

- potentially double counting payment fees
- not using retailer market-share when averaging avoided fees
- not adjusting the fees to reflect how often customers actually incur the fees.[193]

Etrog also considered consumers ascribed zero value to the provision prohibiting the charging of late payment fees—given many customers were unaware they were being overcharged late fees

[191]Cotton Australia, sub. 5, p. 6; QEUN, sub. 12, p. 33.
[192] Canegrowers, sub. 6, p. 7; QEUN, sub. 12, p. 36; Etrog, sub. 14, p. 12.
[193] Etrog, sub. 14, pp. 10–15.

by retailers until enforcement action (initiated by the regulator not the customer) was taken and retailers were directed to repay these fees to customers.

Further, Etrog said the value customers place on terms and conditions in standing offer contracts can only be determined by the customers themselves and we should conduct market research to ask customers what the value is rather than making our own judgement. [194]

On the other hand, EQ supported continuing to include a standing offer adjustment into notified prices to reflect the additional value that standard contracts provide.[195]

In considering the DMO and any adjustments to notified prices:

- QEUN said the DMO adjustment is at odds with 'the QCA's insistence that the "standing offer adjustment" charge must be maintained to promote retail competition in regional Queensland'[196]
- Canegrowers said, in the context of the new transitional tariffs, notified price bills should not exceed the Energex DMO, as it would be an unsustainable outcome under the UTP[197]
- 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.[198] More broadly, EQ raised concerns that regional prices are significantly lower than the DMO and said this indicates clearly there are errors in the calculation of retail costs included in notified prices.[199]

Analysis and final 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 notified price bills do not exceed the equivalent DMO bill in SEQ.

We note stakeholders' comments on the DMO comparison in context of setting the new transitional tariffs. While this matter was raised in the context of the standing offer adjustment, we address it in the discussion on new transitional tariffs (section 3.3).

Level of the adjustment

Under the delegation, we must consider basing the standing offer adjustment on the value of more favourable standard contract terms and conditions relative to market contracts and including an adjustment that is similar to the adjustment in previous determinations (5 per cent of total costs).

Although some customers would prefer that no adjustment was included in notified prices, we consider standard contracts typically provide more favourable terms and conditions than market contracts. These benefits include simpler pricing, access to paper bills at no extra cost, better

[194] Etrog, sub. 14, pp. 10–15.
[195] EQ, sub. 3, p. 16.
[196] QEUN, sub. 12, p. 33.
[197] Canegrowers, sub. 6, p. 3.
[198] EQ, sub. 3, p. 3.
[199] EQ, sub. 8, pp. 14–15.

payment terms (which can include bill smoothing) and ongoing certainty of terms (i.e. retailers cannot change terms or impose restrictions, as they can under market contracts). That said, because of recent market developments, we have observed changes in retailer market offers that may affect the ongoing value of standard contract terms and conditions (discussed under 'recent market developments' below).

In previous determinations, our approach involved assessing SEQ market contract costs (e.g. the fees and charges a customer could incur) as a proxy for quantifying regional Queensland standard contract benefits (e.g. the fees and charges a customer could avoid[200]).

While there are some difficulties and inherent limitations with this type of analysis, we remain of the view that this approach is appropriate and provides a quantifiable proxy for the value associated with the favourable terms and conditions attached to standing offer contracts. The approach involves:

- 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 a small customer in SEQ on retail market contracts.

Our approach relies on publicly available retailer cost data, which ensures the value is based on the fees and charges already levied by individual retailers in a competitive market. As such, we have not pursued the alternative methods suggested by stakeholders, including conducting a survey to assess the value customers ascribe to particular fees and charges (instead of using market data), or (if market data is used) making adjustments to reflect retailer market share. These methods are likely to reflect subjective assessments by us or individual stakeholders, are likely to be less transparent and may not reflect what is occurring in the market.

Supporting market data

Our methodology calculates the maximum dollar value of fees and charges a SEQ market customer could incur under each retailer's individual set of fees and charges, without double counting any mutually exclusive fee types.[201] The maximum fee amount for each retailer is a simple accumulation of each fee type levied by that particular retailer.[202] This means zero values (either where a retailer did not offer that service or offered it but did not charge for it) are included in the analysis—but ultimately have no bearing on the final accumulated value of each retailer’s maximum fees and charges.

Using market data from the June quarter of 2019–20[203], 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)

[200] More information on this approach is contained in chapter 6 of the QCA's 2019–20 final determination on notified prices.

[201] Typical customer based on the average flat rate market offer bill for a residential and small business customer in 2019–20, as reported in our SEQ retail electricity market monitoring 2019–20 report.

[202] QCA, SEQ retail electricity market monitoring 2019–20, November 2020, p. 65 (table 21) and p. 71 (table 23).

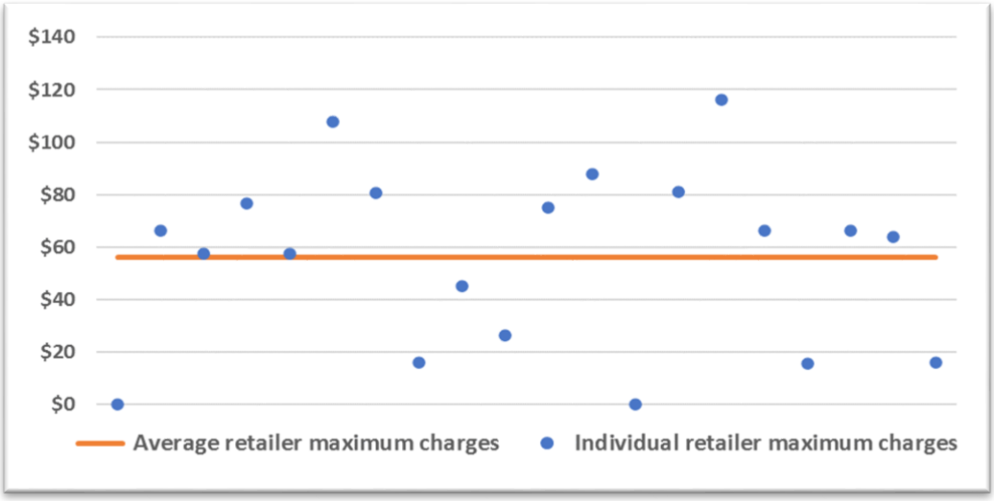
[203] QCA, SEQ retail electricity market monitoring 2019–20, November 2020, Chapter 4.

- the maximum additional fees that could be incurred annually by a SEQ retail market contract customer range from $0 to over $110, with an average of around $55. This equates to around 3.6 per cent of a small customer's annual bill (see Figure 5.2).

Figure 5.1 Types of SEQ retail market offer fees and charges for small customers

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

Figure 5.2 Annual fees and charges in SEQ market contracts, by retailer[204]



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), which we believe better reflects the potential costs that may be incurred.

We reviewed stakeholder concerns regarding the overstating of costs, but are satisfied our calculations are appropriate, including because

- we are seeking to use the maximum avoided fees for each retailer as a quantifiable proxy for the maximum benefit a customer can derive from the favourable terms and conditions of a standing offer contract, therefore, we necessarily need to include the full fee amount levied

[204] 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.

by each retailer, rather than averaging across the percentage of customers who may incur them.

- the costs presented in Figure 5.1 are for illustrative purposes only, to demonstrate the average amount retailers *who charge a particular fee for a service or late payment penalty* can levy to market contract customers, and do not directly accumulate into Figure 5.2 or the calculation of the $55 value.

Recent market developments

Recent market developments may inform our assessment in future determinations, particularly given these have impacted how customers and retailers interact in the market. Recent regulatory reforms have been aimed at improving safety net provisions for consumers and influencing the way retailers communicate retail market offers to consumers.[205] As a result, 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.

Recent 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[206]:
  - bills for standing contract customers have decreased—the average annual bill decreased by 13.8 per cent in the September 2019 quarter
  - bills for market contract customers are less risky; that is, 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—the average annual standing offer bills were $110 higher than average annual market offer bills in the September 2019 quarter, whereas they were $262 higher in the June 2018 quarter.

We have also observed changes in retailers' market contract terms and conditions. For instance, there are fewer (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, like bill smoothing available on standing offer contracts).

Our observations suggest the value of standard contract terms and conditions has likely diminished due to broader improvements in retail market offers aimed at protecting consumers. However, 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.

[205] 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, specifies how retailer prices and discounts must be advertised, published, or offered.
[206] QCA, *SEQ retail electricity market monitoring 2019–20*, November 2020, pp. 10–11, 50.

DMO comparison

We have not made any changes to the level of the standing offer adjustment based on the DMO comparison. This is because none of the customer bills based on final notified prices exceeded their equivalent DMO bills in SEQ (for details on the DMO comparison, see Appendix F).

Based on our comparison, notified price bills for tariff 11 and 20 are approximately $52 and $25 less than the equivalent DMO bills. EQ suggested this differential clearly indicates an error (specifically in relation to the way retail costs included in notified prices have been determined). We do not consider this to be the case, given the different purpose and frameworks that apply (see section 5.5).

We disagree with QEUN's comment stating the DMO adjustment is at odds with 'the QCA's insistence that the "standing offer adjustment" charge must be maintained to promote retail competition in regional Queensland'. The promotion of retail competition has been a consideration in the inclusion of the headroom adjustment in large customer retail tariffs, and not for the small customer standing offer adjustment (see section 5.2).

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.[207]

Before 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 that headroom was effective in promoting competition.[208]

Stakeholder comments

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 area.[209]

Analysis and final 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 position is to not include a headroom allowance in notified prices for large customers this year.

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.

[207] Electricity Act, s. 90(5)(a)(ii).
[208] QCA, *Regulated retail electricity prices 2020–21*, final report, June 2020, p. 38.
[209] QFF, sub. 1, p. 4; Canegrowers, sub. 11, p. 3; QEUN, sub. 12, p. 33; Cotton Australia, sub. 9, p.2.

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.[210]

Such an arrangement could lead to an over- or under-recovery of SRES costs, which we account for through a cost pass-through.

Stakeholder comments

Etrog did not support a pass-through of the SRES costs, as it considered they are an estimate of costs that is the same as all other cost categories.[211] Etrog said that any pass-through needs to be compared to the previous DMO cap to ensure that if the SRES costs were correctly estimated, the total price would not exceed the DMO cap.[212] Etrog noted that this issue would be avoided if the pass-through mechanism did not apply.[213]

Analysis and final position

Our 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 unlike other cost components, the under-recovery of SRES costs was driven by a factor that is outside the control of the regulated entity (i.e. the SRES liabilities determined by the CER). Further, the inclusion of a SRES cost pass-through allows us to better align notified prices with the UTP-consistent costs of supply.

The delegation requires us to compare the calculated notified prices (which include the cost pass-through) to the current DMO as set by the AER.[214] We would reduce the standing offer adjustment if the notified prices were higher than the current DMO for south east Queensland.[215] The delegation does not require us to make comparisons to the previous year's DMO.

We have updated the SRES liabilities in our final determination based on the CER's latest determination for 2021. Retailers are required to purchase more certificates to surrender than the CER 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.

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.

[210] The CER typically determines the final SRES liabilities for the second half of the financial year about nine months after our final determination.
[211] Etrog, sub. 14, p. 14.
[212] Etrog, sub. 14, p. 14.
[213] Etrog, sub. 14, p. 14.
[214] Appendix A: Minister's delegation, terms of reference, clause 2(a).
[215] If the standing offer adjustment is reduced to zero and the bill is still greater than the DMO, then no further adjustments are required.

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.

EQ considered SAC class metering charges should be aligned with metering type installed at the premises.[216] At this stage, we do not consider altering the classification is appropriate, as the metering cost information used to estimate large customer metering costs is aligned to customer consumption groups, not metering installation type. Based on this information, it is not possible to determine metering costs by metering installation type; therefore, our position is to continue to classify metering charges by annual consumption.

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

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

5.5 Additional issues raised by stakeholders

Table 5.1 addresses issues stakeholders raised that are not addressed elsewhere in this report.

Table 5.1 Additional issues raised by stakeholders

Stakeholder comment	Our response
Information and customer education A few stakeholders said customers should be provided with further information on tariff options[217] and commented that: • many customers are not aware of the tariff they are currently on, including customers on obsolete tariffs due to expire. Additional tools about the different tariffs should be made available to businesses[218] • the range of new tariffs should be communicated effectively, and we should provide more education when introducing new tariffs[219] • we should direct the Queensland Government and Ergon to devote significant efforts to educate customers on their tariff options and the most cost-effective tariff for their circumstances.[220]	We appreciate stakeholder views about the need for more information and customer education on tariff options. It is important customers understand which tariffs best meet their circumstances to enable them to make informed decisions. This report, along with the accompanying information booklet, includes information about tariff prices, structures and eligibility criteria to inform customers on the tariff options available. However, it is critical customers engage with their electricity retailer for more detailed information on which tariff options would best suit their needs. Retailers play a key role in providing information, educating customers and disseminating tariff information, given their 'on-the-ground' relationship with customers. Additionally, retailers have detailed customer data and actual historical usage data, which allows them to provide information tailored to a customer's individual circumstances. We also encourage retailers to engage with their customers and provide tailored information on the tariff options available to them. The scope of our review does not extend to directing Ergon Retail or the Queensland Government to undertake customer education tasks, as some stakeholders requested. We note, however, Ergon Retail's comments that it has worked closely with stakeholders (in particular those on obsolete tariffs) and will incur costs associated

[216] EQ, sub. 8, p. 17.
[217] CPAQ, sub. 2, pp. 5–6; Agforce, sub. 10, p. 2; QEUN, sub. 12, p. 26; QFF, sub. 7, p. 3; Cotton Australia, sub. 9, p. 2.
[218] CPAQ, sub. 2, pp. 5–6; QEUN, sub. 12, p. 26.
[219] Agforce, sub. 10, p. 2; QFF, sub. 7, p. 3.
[220] Cotton Australia, sub. 9, p. 2; QFF, sub. 7, p. 4.

<table>
<tr><th>Stakeholder comment</th><th>Our response</th></tr>
<tr><td></td><td>with managing customer eligibility and education for new tariffs.[221]</td></tr>
<tr><td>Stakeholder consultation
Etrog said there is a strong need to address pricing and other matters based on consumer impacts, rather than focus on industry-facing costs and positions. It also said the stakeholder virtual workshop was more accessible for customer representatives to attend.[222]
QEUN said it participates in our consultation process but is yet to see any evidence we (or the Queensland Government) have adopted any of its recommendations.[223]</td><td>We placed greater emphasis in recent reviews on presenting information to better meet the needs of stakeholders, including:
publishing an information booklet alongside the draft and final reports that outlines key issues (including price and non-price aspects of the review)
providing graphs showing bill impacts for all major residential and small customer tariffs
conducting the stakeholder workshop online, which, as Etrog noted, made it more accessible to everyone.
However, we strive to continually improve our approach, including through stakeholder feedback (such as the comments Etrog provided).
We continue to encourage stakeholders to participate in our consultation processes and recognise the following as evidence that, over time, stakeholder views have influenced matters relevant to our determinations:
setting a 7-year phase-out period (transition period) for customers on obsolete tariffs (starting in 2013–14) to align with the remaining life of irrigation equipment
removing the headroom allowance in large customer tariffs
reducing the standing offer adjustment to 3.6 % in small customer tariffs
introducing several new retail tariffs based on tariffs introduced as part of the network reforms, including new controlled load tariffs
updating the retail cost benchmark to take account of more recent market data.</td></tr>
<tr><td>Policy matters
Stakeholders raised concerns around:
the Queensland Government's non-reversion policy[224] and threshold[225]
the transparency of reporting on government policies and the impact of these on the broader Queensland economy (e.g. the UTP, payment of the CSO to Ergon Network instead of Ergon Retail, solar bonus scheme and headroom).[226]
Stakeholders called for an assessment of electricity prices on industries, regions and the</td><td>Stakeholders commented on a range of matters which go beyond the scope of our review.
The framework in which we operate sets boundaries for considering how notified prices should be set (see section 1.2). The Minister's delegation does not unlock investigative and decision-making powers to assess all concerns stakeholders raise (e.g. affordability for particular industry groups in regional Queensland), or implement measures proposed by stakeholders aimed at addressing these concerns (e.g. changing the Queensland Government's non-revision policy and threshold, or who receives CSO funding). These concerns arise in connection with the development and operation (legislation and policy) of the overarching framework, rather than how a</td></tr>
</table>

[221] EQ, sub. 8, p. 4.
[222] Etrog, sub. 14, pp. 1, 4.
[223] QEUN, sub. 12, p. 22.
[224] CPAQ, sub. 2, p. 5.
[225] QEUN, sub. 12, p. 37.
[226] QEUN, sub. 12, p. 1; Canegrowers, sub. 11, p. 3.

Stakeholder comment	Our response
wider Queensland economy, as well as on customers' ability to pay.[227] Stakeholders wanted us to look at small business customer trends during covid-19[228] and conduct ex post reviews on Ergon Retail.[229] EQ supported the removal of the EasyPay Rewards scheme (which will not be available in 2021–22) from the tariff schedule.[230]	particular task is performed within this framework (our role in setting notified prices). On the matters stakeholders raised, we note: • the Queensland Government's 'non-reversion policy'[231] is operational under s. 19C of the National Energy Retail Law (Queensland) • the Minister's delegation provides for us to set notified prices, it does not extend to undertaking ex post reviews of the type stakeholders raised • provisions relating to the Queensland Government's EasyPay Rewards scheme have been removed from the tariff schedule, as this scheme expired on 1 September 2020.
Access to load-control tariffs Cotton Australia and QFF said we should allow all customers to access the large customer load control tariffs (tariffs 60A and 60B), regardless of their location.[232] If not, we should allow existing large customers who access obsolete tariffs 62, 65 and 66 to access the new transitional network tariffs.[233]	The large customer load control tariffs require the installation of network signalling equipment (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 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 that meet their circumstances. Information on customer eligibility for the new transitional network tariffs is set out in section 3.3.1.
Obsolete tariffs QEUN recommended maintaining the obsolete tariffs until less than 500 customers are left on these tariffs and said Ergon Retail should report on the: • type of businesses on tariff 21 • customer impact of tariff alternatives • the number of customers on each obsolete tariff monthly.[234]	In our 2013–14 determination, we provided customers on obsolete tariffs a 7-year period to transition to an alternative tariff (until June 2020). At the end of that period, the Queensland Government extended the expiry date by another year to give customers further time to seek alternative arrangements (until 30 June 2021). Overall, customers have had 9 years to prepare to move to standard tariff prices and structures. Customers on tariffs 62, 65 and 66 may be eligible to access the new transitional tariffs, whose tariff structures are based on those obsolete tariffs. We encourage affected customers to engage with Ergon Retail to discuss the most suitable tariffs available to them, based on their own individual circumstances. It is a matter for Ergon Retail as to the reports it publishes on its customers. Stakeholder groups who wish for more detailed aggregate reporting can engage directly with Ergon Retail.
Network tariffs	The network prices and tariff structures are approved by the AER, forming part of the AER's five-yearly regulatory

[227] QEUN, sub. 12, p. 22; Canegrowers, sub. 11, p. 3.
[228] QEUN, sub. 12, p. 5.
[229] Canegrowers, sub. 11, p. 4.
[230] EQ, sub. 3, p. 17.
[231] In 2018, the Queensland Government removed the non-reversion policy for residential and small business customers.
[232] QFF, sub. 7, p. 3.
[233] Cotton Australia, sub. 5, p. 4, sub. 9, p. 2.
[234] QEUN, sub. 12, pp. 24–27.

Stakeholder comment	Our response
Canegrowers said network tariffs do not conform to the network pricing objective and the long-run marginal cost pricing principle.[235] It also said we should identify and report irregularities and inconsistencies in Ergon Network's tariffs.[236]	period reviews and annual price-setting processes for Ergon Network and Energex. Stakeholders can participate in the AER's public process, including providing comments on network pricing, as part of these reviews.
Application of kVA charging EQ supported retaining in the tariff schedule the two exceptions to the application of kVA charging parameters for large customer tariffs.[237] Ergon Retail requested that customers with digital meters who are moving from expiring obsolete tariffs to standard tariffs with a kVA charging parameter be given the choice of using a kW charging parameter for 12 months. It said this would limit the price shock for customers who will already see a substantial price increase when moving off their obsolete tariff.[238]	We retained the two exceptions to the application of kVA charging: • 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 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). However, in light of Ergon Retail's submission, we decided to introduce an additional exception to the application of kVA charging parameters. This is to allow a large customer with a digital meter that moves from an obsolete tariff onto a tariff with both a kW and kVA charging parameter to be able to choose either the kW or kVA charging parameter for 12 months, after which a kVA charging parameter will apply. We consider this will ease the transition of these customers from obsolete tariffs to standard tariffs.
Demand charges under 5-minute settlement EQ sought to clarify how demand charges should be calculated, given the commencement of the AEMC's five-minute settlement reforms on 1 October 2021 (i.e. whether demand should be averaged over 30 minutes or charged over five minutes).[239]	As per the retail tariff schedule, demand is the average rate of use of electricity over a 30-minute period. We have not made any changes to these arrangements as part of this determination, noting the five-minute settlement reforms will not commence until partway into the tariff year. Any changes made now would also be in advance of any changes that might be made at the network level. This matter could be considered as part of a future price determination.
Demand definition EQ raised a potential issue with the definition of demand included in the retail tariff schedule, namely that the definition does not make an adjustment for export to the distribution network. It considered that, as this type of adjustment is made by Ergon Network at the network level, it could result in Ergon	We have not made any changes to the demand definition at this time. It is unclear what the scope of this potential issue is and what changes EQ is seeking in order to address it, e.g. whether this is an issue for the calculation of demand for all customers, whether it is limited to the CAC and ICC customer classes, or whether it is a kVA-specific issue.

[235] Canegrowers, sub. 6, p. 5.
[236] Canegrowers, sub. 11, p. 2.
[237] EQ, sub. 3, p. 17.
[238] EQ, sub. 8, p. 18.
[239] EQ, sub. 8, p. 15.

Stakeholder comment	Our response
Energy Retail determining a demand figure that is different than what is calculated by Ergon Network.[240]	Also, EQ raised this only after our draft determination. As such, other stakeholders, including potentially affected customers, would not have had any opportunity to give their views on this. This is particularly relevant, given that the extent of this issue and the potential customer impacts are unclear to us.
Load-shape retail charges for ICC customers Ergon Retail suggested that the QCA introduce load-shape retail charges for ICC customers to further enhance retail prices for this customer type, as an ICC customer might not have the assumed Ergon net system load profile load shape.[241]	It is unclear which cost component EQ referred to in referring to 'retail charges'. Further, the load profiles for ICC customers are not publicly available. As this issue was raised by EQ after the draft determination, other stakeholders, including potentially affected ICC customers, would not have had the opportunity to provide views on this approach.

[240] EQ, sub. 8, pp. 16–17.
[241] EQ, sub. 8, p. 15.

6 NOTIFIED PRICES

This chapter sets out notified prices for 2021–22. A breakdown of the notified prices by cost component is provided in Appendix H. The gazette notice, which includes the 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 Notified prices—residential customers (excl. GST), 2021–22

Retail tariff	***Fixed***[a]	***Usage***			***Demand***	
		Off-peak/flat	***Shoulder***	***Peak***	***Off-peak/flat***	***Peak***
	c/day	***c/kWh***	***c/kWh***	***c/kWh***	***$/kW/mth***	***$/kW/mth***
Tariff 11—residential (flat-rate)	88.392	19.782				
Tariff 12A—residential (time-of-use)[b]	69.967	16.461		51.260		
Tariff 12B—residential time-of-use[c]	88.392	14.664	16.398	26.241		
Tariff 14—residential seasonal (time-of-use demand)[d]	42.958	13.079			7.004	48.769
Tariff 14A—residential time-of-use demand[e]	87.252	16.807			2.563	
Tariff 14B—residential time-of-use demand[e]	87.252	14.045			7.320	
Tariff 31—night rate (super economy)		13.026				
Tariff 33—controlled supply (economy)		14.313				

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 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)	121.032	22.551			
Tariff 22A—business (time-of-use)[b]	110.206	20.760	54.463		
Tariff 24—business (time-of-use demand)[c]	57.590	15.260		7.376	73.402
Tariff 24A—business (time-of-use demand)[d]	119.789	21.172		2.402	
Tariff 24B—business (time-of-use demand)[d]	119.789	18.670		9.580	
Tariff 34—business (interruptible supply)	110.983	16.682			
Tariff 41—low voltage (demand)	625.564	13.688		18.350	
Tariff 91—unmetered		19.413			

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 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	121.032	150.351	179.773	209.196	238.618	22.551		
Tariff 22B—small business time-of-use inclining band [b]	121.032	150.351	179.773	209.196	238.618	18.677	21.657	30.778

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 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)	4048.684	10.860		26.050		23.444	
Tariff 45—over 100 MWh medium (demand)	13132.311	10.860		21.125		19.013	
Tariff 46—over 100 MWh large (demand)	34223.182	10.860		17.320		15.587	
Tariff 50—over 100 MWh seasonal time-of-use (demand)[b]	3413.813	12.852	10.491	10.551	68.077		
Tariff 50A—large business time-of-use demand[c]	15816.913	11.290				13.582	2.717
Tariff 60A—large business flat-rate interruptible supply (primary)	4048.684	18.459					
Tariff 60B—large business flat-rate interruptible supply (secondary)		18.459					
Tariff 71—street lighting		23.770					

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 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)	25506.786	10.265	5.861	3.483	3.196
Tariff 51B—high voltage (CAC 33 kV)	18976.186	10.265	5.861	4.243	3.311
Tariff 51C—high voltage (CAC 22/11 kV Bus)	17844.986	10.265	5.861	4.884	4.015
Tariff 51D—high voltage (CAC 22/11 kV Line)	17198.586	10.265	5.861	9.423	8.098
Tariff 53—high voltage (ICC)	25322.071	10.265		3.483	3.196
ICC site-specific—high voltage	2488.271	8.816		0.199	0.182

Table 6.6 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)	14532.186	10.193	9.847	5.861	5.992	12.437
Tariff 52B—high voltage (CAC STOUD 22/11 kV Bus)	14532.186	10.193	9.847	5.861	4.248	46.898
Tariff 52C—high voltage (CAC STOUD 22/11 kV Line)	14532.186	10.193	9.847	5.861	7.735	76.547

Table 6.7 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)	4048.684	10.702	18.628

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

Table 6.8 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]	103.470	52.963	44.313	16.744		
Tariff 65A—time-of-use tariff[b]	103.270	41.488		21.473		
Tariff 66A—dual–rate demand tariff[c]	210.670			20.240	3.744	11.303

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.*

c *Tariff 66A has a monthly dual-rate capacity charge, instead of an annual dual-rate capacity charge. The capacity charge is determined by whichever is larger—the connected motor capacity used for irrigation pumping or 7.5kW.*

Table 6.9 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 Metering charges—small customer advanced meters (excl. GST), 2021–22

Description	*Charge Type*	*Metering charge (c/day)*
Primary tariff	Capital	7.106
	Non-capital	3.330
Secondary tariff	Capital	2.053
	Non-capital	0.988

Source: Data from Energy Queensland.

Table 6.11 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.

GLOSSARY

5MS	Five-minute settlement rule on the NEM, due to start October 2021
ACCC	Australian Competition and Consumer Commission
ACIL Allen	Consulting firm appointed by the QCA to advise on this review
ADM	Advanced digital metering
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
ASX	Australian Securities Exchange
CAC	Connection Asset Customer
CER	Clean Energy Regulator
CLP	Controlled load profile
Code	Electricity Retail Code
CPAQ	Caravan Parks Association of Queensland
CPI	Consumer price index
CSG	Coal seam gas
CSO	Community service obligation payment, a subsidy provided by the Queensland government to EQ to meet the additional costs of supplying electricity to regional Queensland.
Delegation	The delegation issued by the Minister for Energy, Renewables and Hydrogen on 8 January 2021 (see Appendix A)
Distributors	Energex and Ergon Network
DMO	Default market offer
DRECS	Drought Relief from Electricity Charges Scheme
Electricity Act	Electricity Act 1994 (Qld)
EME	Energy Made Easy, an AER website
Energex	Energex Limited (electricity distributor in SEQ)
EQ	Energy Queensland, government-owned corporation which comprises Energex, Ergon Energy Network, Ergon Energy Retail and Yurika
Ergon Network	Ergon Energy Corporation Limited (electricity distributor in regional Queensland)
Ergon Retail	Ergon Energy Queensland Pty Ltd (electricity retailer in regional Queensland)
ESC	Essential Services Commission, the economic regulator in Victoria
ESSO	Electricity Statement of Opportunities, an AEMO report
FCAS	Frequency Control Ancillary Services
GWh	Gigawatt hour
ICC	Individually calculated customer

ISP	AEMO's Integrated System Plan
kV	Kilovolt
kVA	Kilovolt ampere
LGC	Large-scale generation certificate
LNG	Liquefied natural gas
LRET	Large-scale renewable energy target
LRMC	Long-run marginal cost
MCL	Maximum credit limit, assessed and calculated by AEMO
Minister	Minister for Energy, Renewables and Hydrogen
MVA	Megavolt ampere
MWh	Megawatt hour
N	Network costs
N+R	Network + retail cost build-up methodology to set notified prices
NEM	National Electricity Market
NERL	National Energy Retail Law
Notified prices	Regulated retail electricity prices
NSCAS	Network Support Control Ancillary Services
NSLP	Net system load profile
NTP	National Transmission Planner, one of AEMO's functions
POE	Probability of exceedance
PPA	Power purchase agreement
PV	Photovoltaic
QCA	Queensland Competition Authority
QECMM	Queensland Electricity Connection and Metering Manual
QEUN	Queensland Electricity Users Network
QFF	Queensland Farmers' Federation
QNI	Queensland to New South Wales interconnector
R	Energy and retail costs
RBA	Reserve Bank of Australia
RERT	Reliability and Emergency Reserve Trader
RET	Renewable energy target
RPP	Renewable power percentage
RRO	Retailer Reliability Obligation
SAC	Standard Asset Customer
SBS	Solar Bonus Scheme

SEQ	South east Queensland
SRAS	System Restart Ancillary Services
SRES	Small-scale renewable energy scheme
STC	Small-scale technology certificate
STOUD	Seasonal time-of-use demand
STP	Small-scale technology percentage
ToU	Time-of-use
TSS	Tariff structure statement
TWP	Time-weighted average spot price
USE	Unserved energy
UTP	Uniform Tariff Policy
VDO	Victorian Default Offer