Queensland Competition Authority

Final determination

Regulated retail electricity prices in regional Queensland 2023–24

June 2023

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Contents

1 ABOUT OUR REVIEW

1.1 Setting notified prices for 2023–24

We received two delegations from the Minister for Energy, Renewables and Hydrogen (the Minister) to set regulated retail electricity prices (notified prices) and two new retail tariffs to apply in regional Queensland in 2023–24.[1]

We commenced our review to set notified prices in December 2022.

The delegations were issued in accordance with s. 90AA of the *Electricity Act 1994* (Qld).

1.2 Scope

This review is limited to setting 2023–24 notified prices and two new retail tariffs, having regard to the following factors set out in the Electricity Act:

- 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.[2]

We must have regard to factors in the Electricity Act when setting notified prices.

The Minister's delegations state the terms of reference for our review, including:

- the period—the price determination will apply from 1 July 2023 to 30 June 2024
- the timeframes—we must publish reports and make a draft and a final price determination, with the final price determination due by 9 June 2023
- the pricing methodology—we must set notified prices having regard to the network plus retail (N+R) cost build-up methodology (with some additional considerations for the new retail tariffs)
- particular policies or principles—we must set notified prices having regard to, among other matters, the Queensland Government's uniform tariff policy (UTP)
- consultation—we must consult at various stages before making the final determination.

The Minister sets out particular matters we must consider as part of our review, including how we set notified prices.

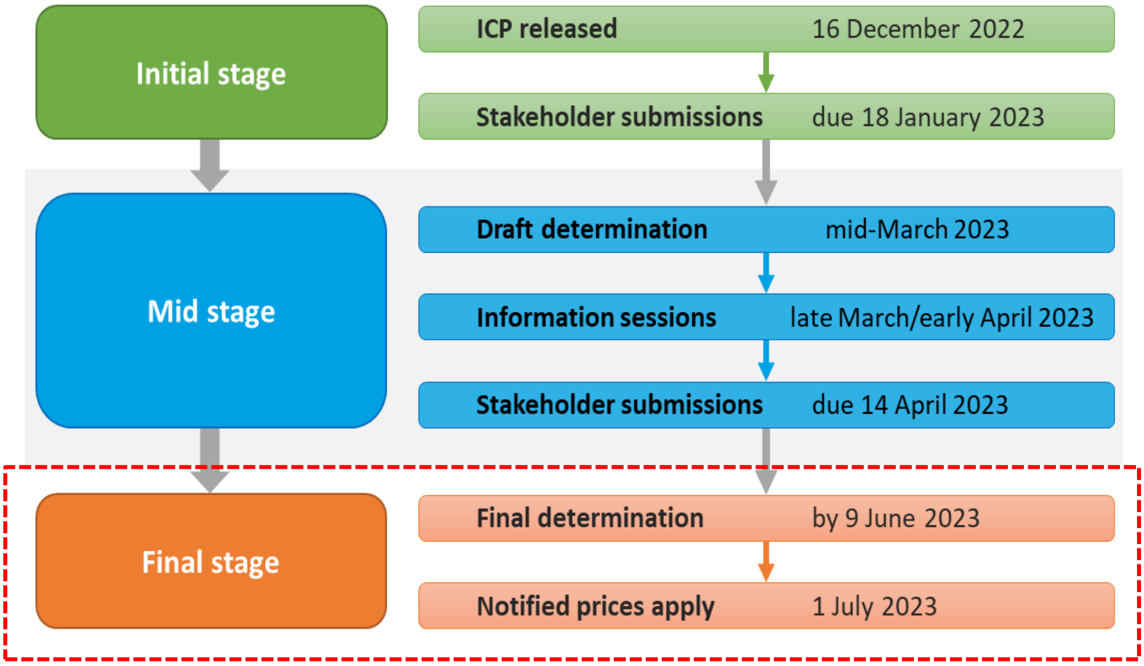
1.3 Process

This determination contains notified prices, presented as bundled prices appropriate to the retail tariff structure (except for site-specific tariffs).[3] In making this determination, we have had regard

[1] Both delegations are provided in Appendix A.
[2] Section 90(5)(a) of the Electricity Act. We may also have regard to any other matter we consider relevant (s. 90(5)(b) of the Electricity Act).
[3] As required in the terms of reference (in cl. 8 of the schedule), which can be viewed in Appendix A. Bundled prices combine the individual cost components (e.g. network, retail and other costs—see chapters 4 and 5) that make up the notified prices.

to relevant factors in the Electricity Act, matters in the delegations, stakeholder submissions[4] and our own analysis.

The key stages of our review are provided below. The notified prices set out in this final determination will apply from 1 July 2023.



1.4 Human Rights Act declaration

As required by the *Human Rights Act 2019* (Qld) (s. 58), we have considered the compatibility of our determination with human rights. Our determination relates to the prices that individuals, 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 the Queensland Government's UTP, which provides that:

> wherever possible, customers of the same class should pay no more for their electricity, and should be able to pay for their electricity via similar common price structures, regardless of their geographic location.[5]

Because of this policy, the electricity prices for most customers in regional Queensland are set below the actual cost of supply. As such, our determination will not limit the above-mentioned rights and is compatible with the Human Rights Act.

[4] We received 14 stakeholder submissions (listed at the end of this report and available on our website).
[5] Appendix A: Minister's delegation for notified prices, terms of reference, cl. 2(a).

1.5 Report structure

The determination is structured as follows:

- Process and timing of our review (chapter 1)
- Indicative customer bill impacts (chapter 2)
- Overarching framework—including our approach for setting prices (chapter 3)
- Individual cost components (chapter 4)
  - Network component (section 4.1)
  - Retail component (section 4.2)
- Other costs and pricing matters (chapter 5)
- Notified prices (chapter 6)
- Stakeholder submissions and references.

1.6 Supporting documents

The following additional information is available on our website.

Technical appendices

The technical appendices provide the Ministerial delegations, further analysis and other relevant information as follows:

- Appendix A: Minister's delegations
- Appendix B: Energy cost approach
- Appendix C: Standing offer adjustment approach and default market offer comparison
- Appendix D: Cost pass-through approach
- Appendix E: Data used to estimate customer impacts
- Appendix F: Build-up of notified prices
- Appendix G: Gazette notice.

Information booklet

An information booklet accompanies this determination—it provides an overview of the key issues relevant for setting notified prices this year (as contained in this report) and potential bill impacts for customers.

Consultant's report

We engaged ACIL Allen (ACIL) to assist us in setting the energy cost component of notified prices. ACIL's report (discussed in section 4.2.1), and data to support its energy cost estimates, is available on our website.

2 INDICATIVE CUSTOMER BILL IMPACTS

Overall, typical customers[6] on all major tariffs can expect an increase in their electricity bills in 2023–24, largely due to an increase in wholesale energy costs and (to a lesser extent) other cost components. This chapter includes **indicative customer bill impact charts**[7] and **a snapshot of the key elements driving increases in notified prices this year**.

Importantly, an individual customer's actual bill will vary based on how much electricity that customer uses. Customers should contact their retailer for further advice and information based on their individual circumstances.

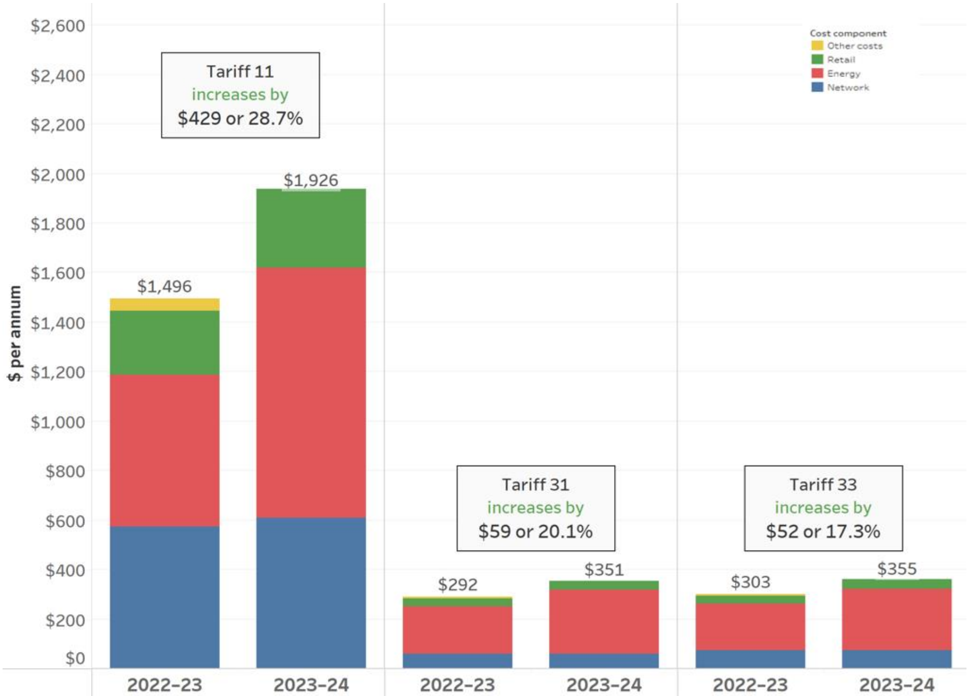
2.1 Small customers

As the indicative bills for the main small customer tariffs include the cost of metering services this year (see section 3.2.2), we have included comparable metering costs in the 2022–23 bills to enable stakeholders to compare bills on a like-for-like basis.

Residential customers

Typical customers on the main residential tariffs (tariffs 11, 31 and 33)[8] can expect to pay around 17.3 to 28.7 per cent more for electricity in 2023–24.

Figure 2.1 Residential customers—bill comparison, 2022–23 and 2023–24 (incl GST)



Note: As other costs are negative for residential customers in 2023–24 (explained in sections 5.1 and 5.2), they do not appear in the figure above.

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

[7] In all charts, amounts are rounded to the closest dollar, percentage changes are based on unrounded amounts.

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

Small business customers

Typical customers on the main small business tariff (tariff 20) can expect to pay around 26.8 per cent more for electricity in 2023–24.

Figure 2.2 Small business customers—bill comparison, 2022–23 and 2023–24 (incl GST)

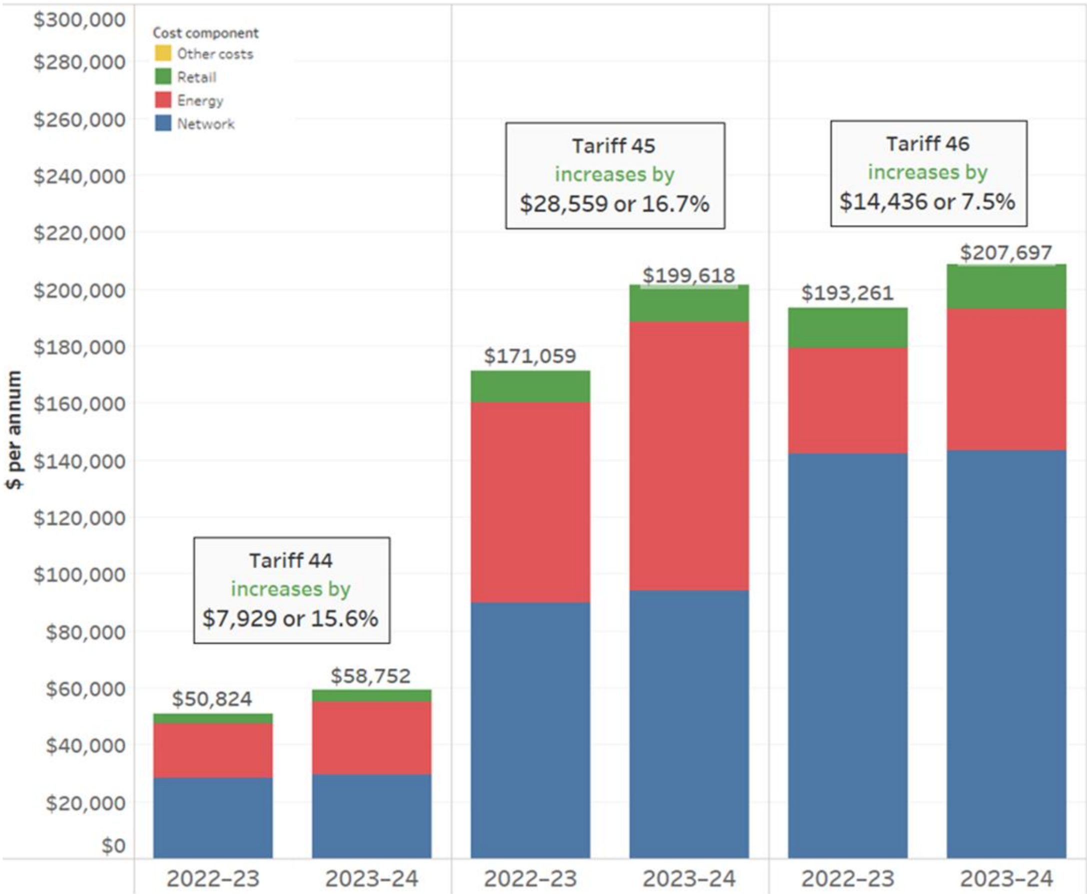
Note: As other costs are negative for small business customers in 2023–24 (explained in sections 5.1 and 5.2), they do not appear in the figure above.

2.2 Large customers

Typical customers on tariffs 44, 45 or 46 can expect to pay around 7.5 to 16.7 per cent more for electricity in 2023–24.

Bill increases are lower for large customers due to smaller increases in wholesale energy costs relative to small customers (see section 4.2.1). This is because large customers have flatter consumption profiles, which are less expensive for retailers to hedge.[9]

Figure 2.3 Large business customers—bill comparison, 2022–23 and 2023–24 (incl GST)



Note: As other costs are negative for large customers this year (explained in section 5.2), they do not appear in the figure above.

2.3 Key elements driving increases in notified prices

Increases in this year's notified prices are the result of increases in the costs that retailers face. Energy costs—in particular, *wholesale* energy costs—are estimated to increase significantly compared to last year due to several factors, including:

- higher gas and coal prices faced by thermal generators, principally due to the war in Ukraine and energy sanctions imposed on Russia. This added further uncertainty to energy markets

[9] Large customers generally tend to consume a greater proportion of their energy during the day than the night, compared to small customers, leading to flatter consumption profiles. In section 4.2.1, we explain how we estimate wholesale energy costs, including the hedging strategies retailers use (e.g. purchasing ASX contracts) to manage spot price risk when purchasing electricity from the NEM.

already impacted by global supply constraints and led to high and volatile gas and thermal coal prices[10]

- uncertainties associated with the availability and reliability of coal-fired power plants and their impacts on the supply–demand balance in the Queensland region. For example, Kogan Creek and Callide C suffered major outages and delays in their return to service.

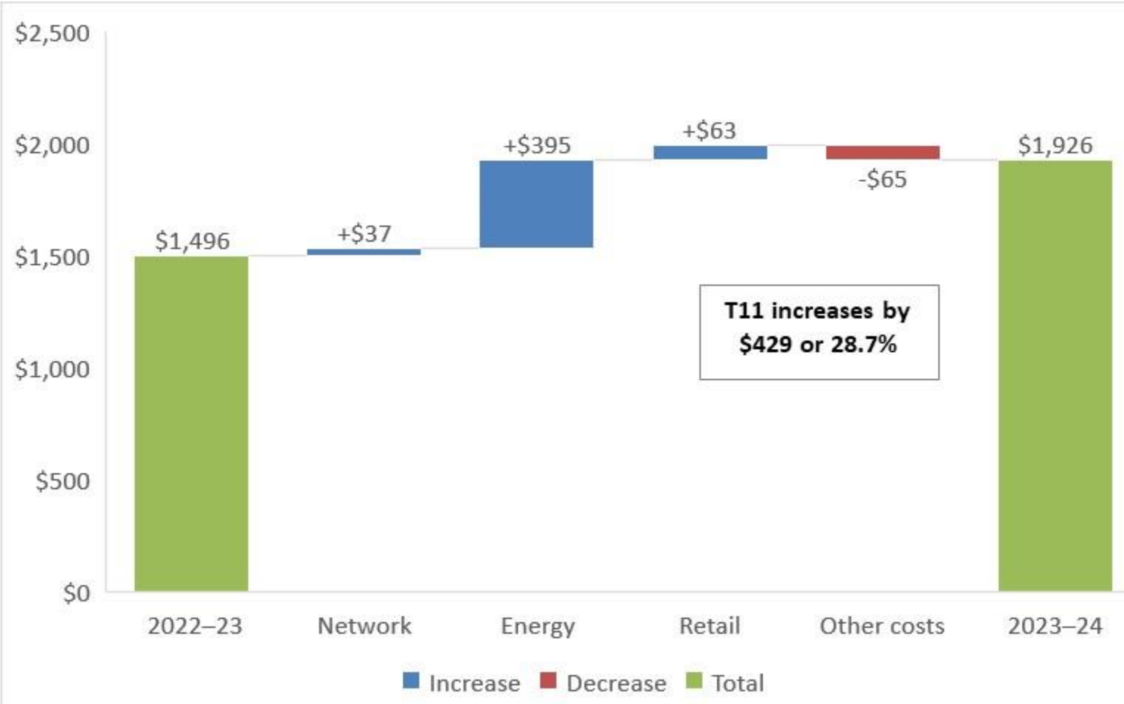
These events have placed upward pressure on wholesale energy prices and are important determinants of Queensland retailers' energy costs and of the wholesale cost of energy in the NEM more broadly. Relevantly, our wholesale energy cost estimates also consider the potential impacts of the intervention by the Australian and Queensland governments in December 2022—that is, the temporary price caps for gas and coal (see section 4.2.1).

Other costs that have contributed to increases in notified prices include:

- higher retail costs, which incorporate metering costs for small customers (see section 3.2.2)
- higher network costs for most customer groups (see section 4.1).

Figure 2.4 sets out the individual cost components contributing to the overall increase for a typical customer on tariff 11. It shows that rising energy costs are the key contributor to the increase in notified prices this year, although other costs have increased as well.

Figure 2.4 T11 bill—changes in cost components, 2022–23 and 2023–24 (incl GST)[11]



[10] Domestic prices of coal and gas are influenced by international prices, because some producers have the option of exporting these resources and receiving international prices. As such, thermal power stations compete with international buyers, and this affects the fuel costs of these generators.

[11] Amounts are rounded to the closest dollar. Metering costs are included. Bills are based on the consumption of a typical customer with a median annual consumption.

3 OVERARCHING FRAMEWORK

This chapter sets out key overarching framework matters that influenced our review and final determination of notified prices. The matters considered are:

- the approach for setting notified prices (section 3.1)
- new matters in the delegation, including developing two new retail tariffs and metering costs for small customer notified prices (section 3.2).

3.1 Approach for setting notified prices

The delegations require us to consider:

- the **uniform tariff policy (UTP)**, which provides that, wherever possible, customers of the same class should pay no more for their electricity, and should be able to pay for their electricity via similar common price structures, regardless of their geographic location
- using the **network plus retail (N+R) cost build-up methodology** to set notified prices, where the N component (network costs) is treated as a pass-through and the R component (energy and retail costs) is determined by us
- new matters relevant to determining the R component for:
  - the two new retail tariffs, using a methodology that will create stronger price signals than the existing time-of-use tariffs
  - the small customer tariffs, determining the retail costs of metering services (including for advanced digital meters (ADMs)) and incorporating these costs in notified prices.

The delegations are broadly consistent with those in previous years—and the way we have set notified prices in past determinations, with some new matters to consider this year (see section 3.2 below).

Stakeholder submissions

Several stakeholders said the cost of electricity continues to be a primary concern in regional Queensland, noting the significant increases expected. Energy debt, equitable pricing and affordability were among the key issues raised.[12]

Stakeholders said it was necessary to consider the impact of price increases on the economy and jobs in regional Queensland.[13] For example, they noted that electricity prices heavily impact:

- business profitability, productivity and investment in regional Queensland
- the sugarcane industry, where electricity accounts for around 20 per cent of direct growing costs for an irrigated producer and any reduction in production effects on-farm employment and a mill's commercial viability
- on-farm irrigation and water supply schemes, which require electricity affordability to be addressed in conjunction with water prices

[12] Cotton Australia, sub 1, p 1, sub 11, p 1; BRIG, sub 2, p 1; PVW, sub 4, p 1; QFF, sub 6, p 3, sub 10, pp 2–3, 5; N Manson, sub 7, pp 1–2; J Pownall, sub 8, p 1; WRIQ, sub 9, pp 3–4; Canegrowers, sub 12, p 2.
[13] WRIQ, sub 9, p 3.

- the levels of vulnerability for households and businesses, including due to factors such as cost of living pressures (e.g. inflation and housing), health costs, long-term impacts of covid-19, and natural disasters.

Stakeholders suggested:

- increasing electricity rebates and support measures for customers impacted by recent flood and rain events, noting the previous Queensland Government 'cost of living' rebate did not apply to primary producers and/or small businesses
- exploring all options to reduce electricity bills for farmers, noting that—between rising water and electricity prices—renewables are becoming a more attractive option to provide affordable energy
- introducing specific agricultural tariffs, which would support increased cane production, increase tax gains for the Queensland Government (as cane farmers' income will rise), increase food production and electricity production from the cane by-product, and support related industries
- in relation to rising energy debt levels in regional Queensland, we must:
  - seek guidance from the Minister on how debt can be written off without affecting customers (noting that being credit defaulted by an energy retailer affects a customer's ability to secure a rental house or a working capital loan)
  - advise the Minister as to whether Ergon Retail is undertaking all necessary measures to prevent financial difficulty and debt accumulation and is complying with its National Energy Customer Framework (NECF) obligations (i.e. regarding credit defaults and furthering the moratoriums on disconnections).[14]

Analysis and position

We are mindful that electricity prices are a primary concern for stakeholders. Customers in regional Queensland, from broader consumer groups to industry-specific consumers, continue to raise concerns around cost pressures and affordability, including with respect to electricity and the notified prices we set.

Under the framework for our review (discussed in section 1.2), we are required to have regard to the Queensland Government's UTP, which is the primary policy mechanism available in the delegations to help deliver more affordable electricity prices to customers in regional Queensland.

This year, we have continued to set notified prices consistent with the UTP—that is:

- for small customers, basing notified prices on the cost of supplying small customers in south-east Queensland (SEQ)
- for large customers, basing notified prices on the cost of supplying large customers in the Ergon Distribution area with the lowest cost of supply that is connected to the NEM (i.e. east zone, transmission region one).

This approach benefits most customers in regional Queensland by setting notified prices lower than would otherwise be the case, and significantly less than the cost of supplying electricity to

[14] Canegrowers, sub 12, p 2; J Pownall, sub 8, p 1; N Manson, sub 7, p 2; QFF, sub 10, pp 3, 5; WRIQ, sub 9, pp 3–4.

these customers.[15] The UTP relies on the Queensland Government's ongoing subsidisation of electricity prices to fund the shortfall (the difference between the cost of supply and the prices paid by customers) through the community service obligation (CSO) subsidy, which is expected to be around $635.2 million in 2022–23.[16]

Consistent with the delegations, we have also continued to set notified prices using the N+R methodology, by:

- passing through the network prices and tariff structures approved by the AER (i.e. the N component)
- adding our estimate of energy and retail costs (i.e. the R component).

When estimating energy costs, we have considered the potential impacts of the Australian Government's Energy Price Relief Plan (in particular, the price caps placed on gas and coal[17]), which was introduced to address higher energy costs and the associated increase in electricity prices (see section 4.2.1).[18]

Further information on the individual cost components of notified prices and our approach to setting these are provided in chapter 4.

We acknowledge notified prices (and annual customer bills) are increasing considerably this year, and despite the mechanisms available in the delegations (which we have employed in setting notified prices), customers may continue to have affordability concerns.

However, the legislative framework requires us to take a cost-based approach to setting notified prices, which means we must reflect the higher costs of electricity supply in our determination. Broadly, cost reflectivity is important to ensure electricity continues to be provided in a safe, secure and reliable way, as well as encouraging efficient consumption and investment decisions. It is also important for equity reasons because it affects how resources are distributed in society (e.g. where prices are not cost-reflective, the difference is funded by taxpayers/government).

As such, while we understand stakeholder concerns, we cannot apply measures beyond those available to us (and outlined in the delegations) to address affordability, including those suggested by stakeholders in relation to water prices, vulnerable customers and the broader economy. However, these are matters we would investigate if we were directed to do so by the government.

The UTP is a broad measure that allows us to set lower electricity prices for most customers, without identifying or addressing affordability issues specific to particular customer groups or industries—these issues are best addressed through direct targeted measures to ensure those in need can access additional support. Such measures include concessions and rebates, broader income support arrangements, consumer protection frameworks and customer hardship programs.

Consideration of such direct measures (including rebates and specific agriculture tariffs) is not our role, or within the scope of this review—it is a matter for governments to determine the

[15] Compared to SEQ, electricity needs to be transported over longer distances and to a lower density customer base.

[16] This includes $66.6 million associated with isolated systems (Queensland Government, *Budget Strategy and Outlook 2022–23*, Budget Paper 2, June 2022, p 202).

[17] Temporary price caps were placed on gas and coal, which are key inputs for thermal generators.

[18] Australian Government, *Energy price relief plan*, media release, Prime Minister of Australia website, 9 December 2022, accessed 23 January 2023.

ongoing appropriateness of support measures to meet social equity, affordability and economic objectives.

Additionally, all retailers (including Ergon Retail) are subject to various customer support requirements set out in the NECF.[19] It is not our role (or within the scope of this review) to provide advice on compliance with the NECF—this is generally the responsibility of the AER.[20]

Box 1 sets out the key support measures available to electricity customers at this time, as well as other potentially helpful resources for customers. Further assistance may also become available in 2023–24.[21] Customers should contact their retailer to discuss individual support measures that may be available, explore options to reduce their energy costs, manage how energy is used (e.g. improvements to energy efficiency could reduce electricity bills) and compare tariff options (e.g. to best suit their needs and consumption patterns).[22]

[19] AEMC, *National Energy Customer Framework*, AEMC website, n.d., accessed 24 April 2023.

[20] AEMC, *How the NECF and the ACL are enforced*, AEMC website, n.d., accessed 24 April 2023.

[21] For example, the Premier stated the Queensland Government would provide an additional rebate on power bills as part of the upcoming 2023–24 state budget (Queensland Parliament, *Record of proceedings*, 10 May 2023, pp 1353–1354).

[22] For example, customers who use electricity during non-peak daytime periods might consider whether the two new retail tariffs are appropriate for them (see section 3.2.1).

Box 1: Support for electricity customers in regional Queensland

Hardship policies

Under the National Energy Retail Law (NERL), retailers have obligations to help customers in financial hardship (or facing payment difficulties).

Ergon Energy Retail's Customer Assist program is available to eligible customers experiencing financial hardship (e.g. payment plans).

Government schemes, concessions and other programs and resources

The Energy Bill Relief Fund will deliver rebates to eligible small customers in 2023–24. Queensland pensioners and seniors may also be eligible for other electricity rebates.

The Home Energy Emergency Assistance Scheme provides one-off emergency assistance for households facing payment difficulties due to an unforeseen emergency or short-term financial crisis that has occurred in the past 12 months.

The Electricity Tariff Adjustment Scheme helps businesses transition from obsolete to standard tariffs, providing transition rebates on electricity bills (eligibility requirements apply).

The ecoBiz program helps small to medium businesses develop an action plan to reduce energy costs, including by tracking usage and providing on-site coaching to identify opportunities to implement initiatives.

The Drought Relief from Electricity Charges Scheme provides drought-declared farming businesses with relief from supply charges on electricity accounts used to pump water for farm or irrigation purposes.

Further information on energy concessions and support for businesses can be found on the Queensland Government's website.

Other resources and information:

- Queensland Farmers' Federation has information on electricity prices, understanding your bill, government schemes and concessions, and specific information and programs available for different industries and customers.
- Ergon Energy Retail has information to assist households, businesses and farming customers.
- The Queensland Government's concession finder has information on energy concessions available to an individual customer, based on their specific circumstances.
- The Australian Government has advice for households and businesses on its energy.gov.au website on how to manage bills and improve energy efficiency and sets out the rebates and assistance available in different jurisdictions, including Queensland.
- Energy Made Easy allows customers to compare energy plans and tariff options based on their energy consumption patterns and other relevant details.

Dispute resolution

Energy and Water Ombudsman Queensland has information for customers on how to lodge a complaint or resolve a dispute involving their electricity, gas or water supplier.

3.2 New matters

The terms of the delegations include additional matters this year, which relate to Queensland Government initiatives aimed at facilitating and accelerating the transition to renewable energy (including the uptake of electric vehicles (EVs)) and targeting 100 per cent penetration of ADMs by 2030.[23]

3.2.1 New retail tariffs

We have been asked to develop two new retail tariffs that build on the existing small customer time-of-use (TOU) tariffs 12B and 22B (the 'solar-soaker' tariffs), namely:

- a residential 3-rate TOU energy tariff
- a small business 3-rate TOU energy tariff.

The Minister said these tariffs would provide suitable options for EV customers to make the most of charging options during the day (when network utilisation is low and solar PV generation is high) and support the use of more renewable energy, consistent with the Queensland Government's initiatives.[24]

In setting the new retail tariffs, the delegation requires us to consider:

- using the same N component as existing TOU tariffs 12B and 22B for the new retail tariffs
- developing a methodology when we set the energy costs (in the R component) to provide greater price differentials between peak and non-peak periods (compared to the existing TOU tariffs 12B and 22B).[25]

The development of these new retail tariffs was initially canvassed as part of last year's notified prices review, and generally supported by stakeholders.[26]

Stakeholder submissions

Stakeholders generally supported developing new retail tariffs with sharper price signals,[27] but said the new tariffs:

- should be available to all customers (not just EV and battery storage customers), including large standard asset customers operating in the 100–160 MWh bracket
- are unlikely to benefit customers experiencing poverty and financial distress
- should consider agricultural irrigation projects (where it is optimal to operate at night) and have a reduced peak period (from five to three hours). Others said the off-peak period

[23] Queensland Government, *Queensland's new Zero Emission Vehicle Strategy*, Queensland Government website, updated 20 September 2022, accessed 31 January 2023. The Queensland Energy and Jobs Plan sets out initiatives to deliver clean, reliable and affordable power and the target for ADMs (*Queensland Energy and Jobs Plan*, website, n.d., accessed 31 January 2023). The AEMC recommended a target uptake of smart meters by 2030 in the NEM (AEMC, *Review of the regulatory framework for metering services*, draft report, November 2022, pp ii, 19).
[24] Appendix A: Minister's cover letter, p 2.
[25] Appendix A: Minister's delegation for the new retail tariffs, terms of reference, cl. 2(b).
[26] QCA, *Regulated retail electricity prices in regional Queensland 2022–23*, final determination, May 2022, pp 22–29.
[27] Ergon Energy Network and Energex, sub 3, p 1; BRIG, sub 2, p 2; EER, sub 5, p 10; WRIQ, sub 9, p 6; Cotton Australia, sub 11, p 1; Canegrowers, sub 12, p 3.

should be adjusted from 9 am to 4 pm to 8 am to 5 pm, to support waste management and recycling sector activities and circular economy objectives.[28]

Stakeholders also raised broader concerns around the impacts and potential costs of implementing government initiatives and said:

- the new tariffs must be cost-reflective to encourage EV users to charge at optimal times
- the costs to upgrade the network (for EVs) must not be spread across all customers and there must be transparency that no additional costs to consumers would result from developing the new tariffs
- users should be consulted on the impacts EVs could have on the NEM and on customers if the existing TOU tariffs are to be removed
- the government policies around solar and wind generation and the roll-out of EVs are likely to put higher demands on the network and in turn those who pay for it.[29]

Instead of introducing the new retail tariffs (in addition to the existing tariffs 12B and 22B), Ergon Energy Retail (EER) said we should repurpose the existing tariffs[30] or make them obsolete (with a 24-month phase-out date), because of:

- the large suite of regulated retail tariffs and the relatively small number of customers on the existing TOU tariffs
- the minimal impact on customers if the existing TOU tariffs are repurposed or made obsolete.

Further, EER said the new tariffs could be a viable replacement for customers moving off expiring tariffs 12A, 14, 22A and 24.[31]

Analysis and position

We have set two new retail tariffs (identified as tariffs 12C and 22C in the tariff schedule)[32] that build on existing TOU tariffs 12B and 22B and apply:

- the network prices used to set the existing TOU tariffs (see section 4.1)
- the retail cost allowances used to set existing TOU tariffs (see section 4.2.2)
- time-varying energy costs, which result in greater price differences between peak and off-peak periods (compared to the existing TOU tariffs), using the energy cost allowances used to set existing TOU tariffs as a base (see section 4.2.1 for further information).

This approach is consistent with our broader pricing approach (see section 3.1) and the specific considerations related to setting the R component for the two new retail tariffs.

Setting energy costs in the way described above is a departure from our usual approach and does not reflect how retailers are likely to incur their costs in practice. However, it is based on the existing wholesale energy cost allowances and is consistent with policy guidance from the

[28] Cotton Australia, sub 1, p 1; BRIG, sub 2, p 2; EER, sub 5, p 10; WRIQ, sub 9, p 7; N Manson, sub 7, p 2; PVW, sub 4, p 1.
[29] QFF, sub 6, pp 4–5, sub 10, p 4; Canegrowers, sub 12, p 3.
[30] Repurposing the existing TOU tariffs would mean tariffs 12B and 22B would be replaced with the new retail tariffs. Customers would no longer be able to access the existing TOU tariffs and there would be no phase-out period needed.
[31] EER, sub 5, p 11, sub 13, p 3.
[32] In the 2023–24 retail tariff schedule to be gazetted (Appendix G).

Minister. It also reflects the evolving market conditions, where the accelerated roll-out of ADMs gives customers the ability to manage their energy use and consumption patterns more efficiently.[33] Time-varying wholesale energy costs are likely to be more appropriate as the penetration of ADMs increases.

We have considered the issues raised by stakeholders:

- Tariff availability—the new retail tariffs:
  - will be available to small customers with smart meters who can access the existing tariffs 12B and 22B (i.e. the new tariffs are not restricted to EV and battery storage customers)
  - will not be available to large customers (operating in the 100–160 MWh bracket), noting consumption thresholds (that define small and large customers) are established in legislation and not something we can change.[34]
- Peak and off-peak periods—these reflect the underlying network prices and tariff structures approved by the AER. Adjusting the time of peak and off-peak periods would not be consistent with the N+R methodology (see section 3.1 and 4.1)
- Broader concerns—the new tariffs have not resulted in any broader cost impacts, or additional EV-specific costs, for customers at this time:
  - The existing and new TOU tariffs are based on the same energy cost allowance. The only difference is the costs are recovered via a flat energy rate (for the existing TOU tariffs) or three different energy rates for off-peak, peak and shoulder time periods (for the new TOU tariffs).
  - While cost-reflective prices are a factor we consider under the Electricity Act, we must also consider the UTP. As all small customers are paying significantly less than the actual costs of supply (see section 3.1), it would not be appropriate to treat the new tariffs any differently, such as stakeholders suggested.
  - As the new tariffs are intended to encourage customers to use electricity during daytime periods (when network utilisation is typically low), this could limit the potential need for network upgrades and associated costs that are of concern to stakeholders.

We also consider providing too many tariff options (particularly of the same tariff type) can be counterproductive and may make it more difficult for customers to assess their options and switch to alternative tariffs,[35] consistent with EER's views.

However, we consider it would be pre-emptive to remove the existing TOU tariffs at this time. It is clear the Minister intended the new retail tariffs be introduced in addition to tariffs 12B and 22B.[36] Also, while similar in structure, there are greater price differentials for the peak and off-peak periods, which will affect customers differently.

As such, we could revisit this matter in future determinations, with the benefit of further information from stakeholders (including customers directly impacted).

[33] We discussed emerging issues and pricing options in the context of EVs in our previous determination (QCA, *Regulated retail electricity prices in regional Queensland 2022–23*, final determination, May 2022, pp 22–29).
[34] We explain in section 5.4 how we are constrained in considering such matters.
[35] See the review of the suite of retail tariffs and rationalisation of tariff options discussed in QCA, *Regulated retail electricity prices in regional Queensland 2022–23*, final determination, May 2022, p 15.
[36] Appendix A: Minister's cover letter, p 2.

3.2.2 Metering costs

We have been asked to:

- include metering costs as part of the R component for small customer tariffs, based on:
  - the costs for standard type 6 meters in the Energex distribution area (SEQ)
  - the costs retailers incur for small customer ADM services in the Energex distribution area
  - the rate of replacement of distributor meters with ADMs
- set a retail charge based on the costs of manually reading meters for customers who have voluntarily disabled the remote communication function of their ADM (known as a 'type 4A meter') based on EER's average costs of manually reading a type 4A meter.

The Minister said this would enable retailers to recover costs associated with all metering services and support the Queensland Government's broader energy plans, which target 100 per cent penetration of ADMs by 2030.[37] The Minister also said it is important to ensure similar customers do not pay different amounts simply based on the type of meter they have (consistent with the UTP).[38]

Stakeholder submissions

Stakeholders had mixed views on how we should determine metering costs and if these costs should be included in the R component of small customer notified prices.

EER welcomed the incorporation of combined metering costs in the R component of notified prices and recommended we apply a similar methodology to that used by the AER for the default market offer (DMO). However, noting our approach was based on the costs incurred by retailers in the Energex distribution area, EER said the resulting metering costs are not sufficient to enable a prudent retailer to recover ADM costs and will have significant financial repercussions for retail businesses as ADM penetration increases. EER said it is imperative to allow for full cost recovery of ADM costs, including amending the gazette to allow it to recover metering provider costs from customers.[39]

Other stakeholders raised concerns around the lack of consultation undertaken and said metering costs would not be transparent if incorporated into the R component (instead of being separately itemised). Other concerns raised were around:

- the potential for double-charging, noting substantial out-of-pocket expenses are incurred to install a new digital meter when installing a solar PV system
- the level of costs—as the penetration of digital meters increases, it should provide an avenue for reducing energy costs to the consumer, given physical reading of these meters is not required.[40]

In relation to the type 4A meter charge, EER said it is difficult to determine the costs of manually reading type 4A meters (because it depends on the customer's geographic location, access to their meter, and the availability of meter reading staff). EER said the rates we used may therefore not be a cost-reflective solution. EER said we should align the type 4A meter charge to the special

[37] Appendix A: Minister's cover letter, p 2; Queensland Government, *Queensland Energy and Jobs Plan: Power for generations—70% Renewable Energy by 2032*, September 2022, p 36.
[38] Appendix A: Minister's cover letter, p 2.
[39] EER, sub 5, pp 10–11, sub 13, p 3.
[40] QFF, sub 6, p 3; QFF, sub 10, p 3; WRIQ, sub 9, p 7; N Manson, sub 7, p 2.

meter read fee in Schedule 8 of the Electricity Regulation 2006 (Electricity Regulation) as a short-term solution, while Energy Queensland works with the AEMC and key energy stakeholders to remove customers' ability to disable meter communications.[41]

Analysis and position

Small customer metering services

We have determined the small customer metering costs consistent with the delegation:

- For primary tariffs, we calculated a weighted cost based on:
  - type 6 meter costs approved by the AER for 2023–24 [42]
  - ADM costs approved by the AER for 2023–24 and applied to set the DMO[43]
  - forecast rates of replacing distributor meters with ADMs for regional Queensland in 2023–24 provided by Energy Queensland (EQ).
- For secondary tariffs, we applied the relevant type 6 meter costs approved by the AER for 2023–24 .[44] We did not include ADM costs, as customers with a secondary tariff will pay for the ADM component through their primary tariff.

This approach means customers will contribute to the overall costs of metering services (type 6 meters and ADMs) and pay the same amount, regardless of which type of meter they have, which is consistent with the UTP.[45] As the ADM cost data used is net of up-front fees already paid by customers, this mitigates the risk of customers being double-charged.[46] We note that, separate from the meter itself, meter wiring and equipment to house the meters (e.g. the switchboard or meter box) are the responsibility of customers.

This should enable retailers to recover costs associated with the provision of metering services (including ADMs, which was not the case in previous years).[47] We have based the ADM costs on the costs incurred by retailers in the Energex distribution area. While EER's costs may differ from the Energex costs, our approach ensures charges are aligned with the costs retailers have actually incurred in SEQ (consistent with the UTP).

By incorporating metering costs into the R component, the costs will be captured in the daily supply charge for each tariff.[48] We have made consequential amendments to the tariff schedule set out in the gazette notice (Appendix G) to reflect this approach for small customers.

Metering service costs are identified separately below to ensure transparency is maintained.

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[41] EER, sub 5, p 10, sub 13, p 3.
[42] AER, *Energex - Annual pricing 2023–24*, AER website, n.d., accessed 11 May 2023.
[43] AER, *Default market offer prices 2023–24*, final determination, May 2023, pp 35–36, 54–55. To derive a cost for small customers, we combined the costs for residential and small business customers by weighting the respective ADM costs by residential and small business customer numbers.
[44] AER, *Energex - Annual pricing 2023–24*, AER website, n.d., accessed 11 May 2023.
[45] Previously, all customers were charged based on the cost of type 6 meters in SEQ.
[46] The AER collected data on the extent to which retailers recover part of their costs through up-front and/or one-off installation fees (AER, *Default market offer prices 2023–24*, final determination, May 2023, pp 31–32; 54–55).
[47] Appendix A: Minister's cover letter, p 2.
[48] The alternative control services (ACS) supplementary charges for type 6 meters with solar PV have not been incorporated into the daily supply charge and can continue to be passed on to customers by retailers.

Table 3.1 Metering service costs included in small customer tariffs, 2023–24 (excl GST)

Description	Metering costs
Primary tariff	17.71 c/day
Secondary tariff	3.39 c/day

Manual reading—type 4A meter

We have set the charge for manually reading a type 4A meter based on the AER-approved special meter read fee for 2023–24, which is $40.98 per meter read (excl GST).[49] While the delegation asked us to set the fee based on the average costs EER incurs when manually reading a type 4A meter, EER has informed us this information is not readily available.[50]

We did consider EER's suggestion to base the fee on Schedule 8 of the Electricity Regulation, but decided that the AER-approved special meter read fee for 2023–24 is a more appropriate benchmark—it represents a similar activity to manually reading a type 4A meter and, having been approved recently, relies on more up-to-date information.[51]

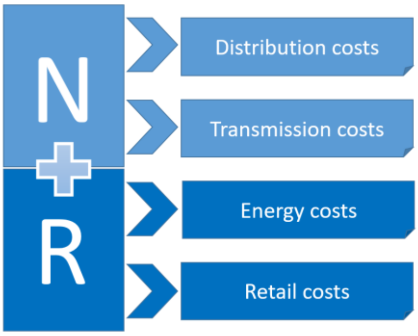
According to EER, very few customers have disabled the remote communication function of their ADM. As such, we do not anticipate any significant financial impacts to EER if this fee is different to its costs given the number of actual meter reads required is likely to be minimal.[52]

Importantly, a type 4A manual meter read fee will only apply to customers that have *voluntarily* disabled the remote communication function of their ADM.

[49] AER, *Ergon Energy - Annual pricing 2023–24*, AER website, n.d., accessed 11 May 2023.
[50] EER, sub 5, p 10.
[51] While schedule 8 of the Electricity Regulation prescribes a maximum charge for a special meter read, the AER-approved special meter read fee is below the maximum charge and is applied by Ergon Energy Network.
[52] EER, sub 5, p 10.

4 INDIVIDUAL COST COMPONENTS

This chapter sets out our positions on matters related to the individual cost components that make up a retail tariff. Many of these matters are identified in the delegations, which we must consider when setting notified prices.



The individual components include:

- the N (network) component (section 4.1)
- the R (retail) component (section 4.2)
- other adjustments and costs (chapter 5).

4.1 Network component

The N component captures the costs of transporting electricity through transmission and distribution networks, as well as jurisdictional scheme charges.[53] These costs are regulated by the AER and reflected in the network prices it approves.

The delegations require us to consider setting the N component in a manner that reflects the overarching framework matters—that is, the UTP and N+R methodology (see section 3.1). This means basing the N component:

- for small customers on:
  - flat and secondary load control tariffs—the relevant Energex network prices (being the charges and tariff structures levied by Energex in SEQ)
  - tariffs 62A, 65A and 66A (limited access obsolete tariffs)—the relevant network prices for Ergon Distribution's east zone, transmission region one[54]
  - all other existing retail tariffs—the price level of the relevant Energex network prices but utilising Ergon Distribution tariff structures
  - for the new retail tariffs—the network prices used to set the existing retail tariffs 12B and 22B (for residential and small business retail tariffs respectively)
- for large customer retail tariffs—the relevant network prices for Ergon Distribution's east zone, transmission region one.[55]

The delegations are broadly consistent with previous years and the way we set the N component in previous determinations. However, there are some additional considerations relating to the new retail tariffs.

Stakeholder submissions

EER supported our approach to setting the N component, in light of the UTP.[56]

[53] In Queensland, these charges generally include costs related to the Solar Bonus Scheme (SBS) and AEMC levy.
[54] This is the Ergon Distribution pricing region with the lowest cost of supply that is connected to the NEM.
[55] Appendix A: Minister's delegation for notified prices, terms of reference, cl. 2(c).
[56] EER, sub 5, p 4.

Other stakeholders asked for more transparency around the Solar Bonus Scheme (SBS) charges included in network costs and said these charges should be funded from consolidated revenue (by the Queensland Government) and not paid by electricity users.[57]

Analysis and position

We have set the N component using the network prices approved by the AER.[58] Consistent with the UTP, this means for:

- small customers on standard retail tariffs, basing the costs on the costs of supply in SEQ (Energex distribution area)
- large customers, and small customers on the limited access obsolete tariffs, basing the costs of supply on east zone, transmission region one (Ergon Distribution's lowest cost region that is connected to the NEM)
- the new small customer retail tariffs, basing the costs on the same network prices as those used to set the existing retail tariffs 12B and 22B (i.e. the costs of supply in SEQ (Energex distribution area)).

Setting the N component in this manner is consistent with our broader pricing approach (see section 3.1) and the approach we have applied in previous price determinations, as well as the specific considerations for the two new retail tariffs (discussed in section 3.2.1).

We are mindful some stakeholders do not support the inclusion of SBS charges in notified prices and would like these charges itemised in the notified prices build-up. However, SBS charges are included in the AER-approved network prices that form the basis of the N component in notified prices and are legitimate costs that Energex and Ergon Energy Network are entitled to recover under the National Electricity Law. As these charges are included in the total AER-approved network prices, it is not necessary for us to separately include (or itemise) these for the purpose of setting the N component for notified prices.[59]

Network costs included in notified prices

Overall, network costs have increased for small and large customers this year. Figures 4.1 and 4.2 show the network costs included in notified prices—compared to last year's estimates—by tariff type, for typical small and large customers.

[57] BRIG, sub 2, pp 2–3; WRIQ, sub 9, p 7; Cotton Australia, sub 11, p 1.

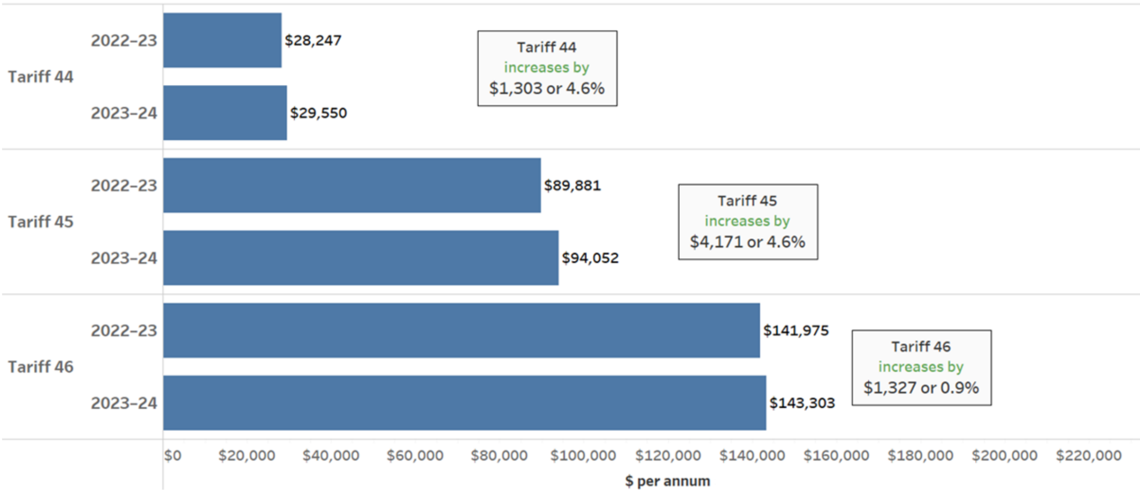
[58] On 4 May 2023, the AER approved network prices for Energex and Ergon Distribution to apply from 1 July 2023 (AER, *Energex - Annual pricing 2023–24*, AER website, n.d., accessed 11 May 2023; AER, *Ergon Energy - Annual pricing 2023–24*, AER website, n.d., accessed 11 May 2023).

[59] Stakeholders can find further information and details on these charges in information Energex and Ergon Energy Network provide to the AER as part of the annual pricing proposals (see, for example, Energex, *Pricing proposal*, March 2023, pp 18–19).

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

Note: The amounts in the figure are rounded. The percentage changes are based on unrounded amounts.

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



Note: The amounts in the figure are rounded. The percentage changes are based on unrounded amounts.

4.2 Retail component

The R component captures the costs retailers incur when they purchase electricity from the NEM to supply their customers, run their general operations (including a return for the risks that retailers face when operating in the market) and provide metering-related services. This comprises of:

- energy costs (section 4.2.1)
- retail costs, including metering-related costs (section 4.2.2).

4.2.1 Energy costs

Energy costs are a key cost component of notified prices and include the costs associated with wholesale energy costs, other energy costs (including the Renewable Energy Target) and energy losses.

We engaged ACIL to provide expert advice and inform our review and energy cost estimates.[60] As with our previous reviews, all information we relied on in ACIL's report is available on our website.

Stakeholder submissions

EER observed that market conditions have changed dramatically since our last review, noting that both coal and gas prices had risen to record levels.[61] In addition, Canegrowers was concerned that operating problems at Queensland coal-fired power stations (e.g. Callide C and Kogan Creek) are contributing to this problem, which may lead to increases in future wholesale energy prices.[62]

EER said we need to enhance the forecasting method to better reflect the increased spread of risks faced by retailers in two areas:

- spot prices—ACIL's forecasts must include the impact of stress events in the market, including by using the latest market data on movements in fuel costs and generator availability and including the impacts of the government intervention (i.e. price caps for coal and gas) in December 2022. Specifically, EER noted ACIL's spot price forecasts were too low and had not taken into account exemptions relating to the government price caps on gas[63]
- contract prices—while contract prices eased following the government intervention, ACIL's forecasts need to recognise retailers build their hedge positions over a two-to-three-year period in line with their financial risk management policies. Therefore, their contracts were purchased at higher prices well ahead of the government intervention (between May and December 2022).[64]

EER supported using ADM demand profiles to inform the wholesale energy cost estimates but said we should consider the potential impacts and, if necessary, apply a combination of approaches with a glide path to soften any unexpected price impacts for retailers and customers.[65]

When estimating other energy costs, EER supported:

- using a forward-looking approach to estimate NEM fees, as it provides a more reasonable basis for estimating a retailer's expected costs for the coming year
- including costs associated with market events during 2022, namely for:
  - activation of the Reliability and Emergency Reserve Trader (RERT) in June and July 2022
  - retailers' costs to date relating to the administered pricing event (in June 2022), noting that the AEMC is still considering compensation claims and suggested a true-up could be applied in 2024–25 to account for any under- or over-recovery.[66]

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[60] ACIL Allen, *Estimated Energy Costs*, final report, prepared for the QCA, May 2023.
[61] EER, sub 5, p 5.
[62] Canegrowers, sub 12, p 3.
[63] EER, sub 5, pp 4–5, sub 13, p 2.
[64] EER also highlighted the increasing incidence of negative spot prices within the NEM and the illiquidity of cap products in the market and the weighting of caps in our hedge modelling (EER, sub 5, pp 3–8, sub 13, pp 5–7). These matters are addressed in Appendix B.
[65] EER, sub 5, p 8.
[66] EER, sub 5, pp 8–9.

However, WRIQ said any outstanding compensation costs approved by the AEMC should be funded through consolidated revenue (rather than included in other energy costs) given the amount is not material.[67]

New retail tariffs

In setting the energy costs for the new retail tariffs, stakeholders said:

- the energy costs could be further reduced in the off-peak periods to better reflect the higher supply of low-cost solar and wind power during those times[68]
- it is appropriate to use a weighted calculation using both digital meter and net system load profile (NSLP) data to estimate wholesale energy costs until there are sufficient customers on the new tariffs to determine the demand profile.[69]

Wholesale energy costs

Wholesale energy costs relate to the costs retailers incur when purchasing electricity from the NEM. Retailers adopt a range of strategies to reduce their exposure to volatile and rapidly changing wholesale electricity prices (spot price risk), including pursuing hedging (financial), contractual and operational strategies.

The specific considerations for setting the wholesale energy costs for the two new retail tariffs (including to create sharper price signals) are discussed in a separate section below.

Analysis and position

Our position is to estimate wholesale energy costs based on ACIL's advice, which uses a market hedging approach (designed to simulate the NEM from a retailer's perspective) and up-to-date market data.

A core feature of this approach is that it incorporates a hedging strategy that a prudent retailer would adopt to manage spot price risk in the NEM. More specifically, this involves:

- simulating a broad range of expected spot prices that a retailer may face, considering demand profiles, generation costs, power station availability and competitive dynamics
- estimating wholesale energy costs for a retailer that hedges spot price risk through the purchase of ASX Energy contracts.

We consider this approach transparent and likely to produce robust wholesale energy cost estimates that closely reflect prevailing conditions in the NEM and relevant financial markets:

- it uses the latest available information (up to 10 May 2023) on:
  - the uptake of rooftop solar PV, renewable energy traces[70], AEMO's peak demand and supply projections, and market participants' formal announcements on generation availability/operation[71]

[67] WRIQ, sub 9, p 6.
[68] Canegrowers, sub 12, p 3.
[69] EER, sub 5, p 11.
[70] Renewable energy resource traces reflect the availability and quality of renewable resources/generation in different regions, depending on weather and geographical conditions.
[71] This includes the medium-term projected assessment of system adequacy (MT–PASA) published by AEMO. AEMO employs the MT–PASA process to determine if there is sufficient capacity expected to be available to meet forecast demand over the medium term (a 2- to 3-year time horizon). Market participants submit expected plant availability for the next 36 months and are required to update their PASA submission on an ongoing basis.

  - the cost of purchasing electricity in the NEM (via ASX financial contracts) that is publicly available.
- it addresses stakeholder concerns (discussed below and in Appendix B).

As such, we consider this approach is appropriate—it takes account of, among other things, the likely variations in demand profiles and generation supply/costs within the NEM, while still meeting our final determination timeframe.

Compared to last year, our estimate of the wholesale energy costs increases substantially for all customers in 2023–24. For small customer tariffs, the increase is between 41.3 and 81 per cent, and for large customer tariffs, the increase is around 46.8 per cent.[72]

This primarily reflects a substantial increase in the trade-weighted ASX contract prices for base and cap contracts—which is driven by market participants expecting higher spot prices and greater price volatility, likely due to:

- higher gas and coal prices—thermal generators have been facing higher fuel costs due to the war in Ukraine and energy sanctions imposed on Russia (a major global oil, gas and thermal coal producer). These developments have added further uncertainty to energy markets already impacted by global supply constraints[73] (due to the covid-19 pandemic), which led to high and volatile gas and coal prices[74]
- uncertainties associated with the availability and reliability of coal-fired power plants and their impacts on the supply–demand balance in the Queensland NEM region:
  - Kogan Creek began a scheduled outage in September 2022 for a major overhaul, but its return to service was delayed for more than a month due to additional repairs[75]
  - Callide C (unit 3) has experienced a forced outage since October 2022. The operator (CS Energy) initially advised the unit was expected to return to service in February 2023, but delayed this from June to September 2023. CS Energy also delayed the return to service of Callide C (unit 4) from May to October 2023.[76]
  - These outages reduced the average available capacity by around 864MW in Q4 2022.[77]

These market conditions directly impact the costs retailers incur when purchasing electricity in the NEM.[78]

[72] See also Table 5.2 of ACIL's report, which sets out the wholesale energy cost estimates by customer group (ACIL Allen, *Estimated Energy Costs*, final report, prepared for the QCA, May 2023, p 60).
[73] Ng, J, 'Commodities soar as war builds anxiety over supply shortages', *Bloomberg*, 4 March 2022, accessed 31 January 2023.
[74] Domestic prices of coal and gas are influenced by international prices because some producers may have the option of exporting these resources and receiving international prices. As such, thermal power stations compete with international buyers and this affects the fuel costs of these generators.
[75] CS Energy, *Kogan Creek power station overhaul extended*, news release, 12 October 2022, accessed 31 January 2023.
[76] Callide C (unit 4) has been unavailable since May 2021 following a major explosion (CS Energy, *Updated return to service date for Callide C units*, news release, 23 December 2022, accessed 31 January 2023; CS Energy, *Updated return to service date for Callide C units*, news release, 8 March 2023, accessed 9 March 2023).
[77] For Q4 2022, AEMO reported an average output of 4,616MW for black coal in Queensland (AEMO, *Quarterly Energy Dynamics Q4 2022*, January 2023, pp 20–21).
[78] We acknowledge stakeholders' concerns surrounding the sub-optimal maintenance of power stations and the impact of supply limitations on wholesale energy costs. However, we are required to take a cost-based approach to setting notified prices. This includes considering the costs retailers face when purchasing electricity from the NEM. These broader supply-demand issues affect these costs.

Key cost drivers and impacts of government intervention

As previously discussed, the increase in wholesale energy costs reflects the substantial increase in the trade-weighted ASX contract prices. Notably, since the war in Ukraine in late February 2022, ASX base contract prices for Queensland (Q1 2024) increased markedly, reaching a record high of around $243/MWh (Figure 4.3). This reflects market participants' expectations of both higher future spot prices and greater price volatility relating to these events.

In December 2022, the Australian Government partnered with the states and territories to introduce an Energy Price Relief Plan with measures to address high energy costs. As part of this policy, temporary price caps of $12/GJ) for gas and $125/tonne for coal were implemented.

The effects of these price caps have impacted wholesale electricity prices in both spot and contract markets. Our approach captures these impacts using updated market information (until 10 May 2023) on:

- spot prices—observations of generator bidding behaviour since the intervention suggest that these caps have not changed generator bidding behaviour uniformly, which has resulted in less significant impacts than the draft analysis anticipated[79]
- traded contract prices—to calculate the trade-weighted ASX prices for 2023–24, we used contract prices and trade volumes for Queensland since contracts were first traded in March 2020 until 10 May 2023 (inclusive), including the higher prices of ASX contracts retailers acquired from May to December 2022 before the government intervention, consistent with EER's views.

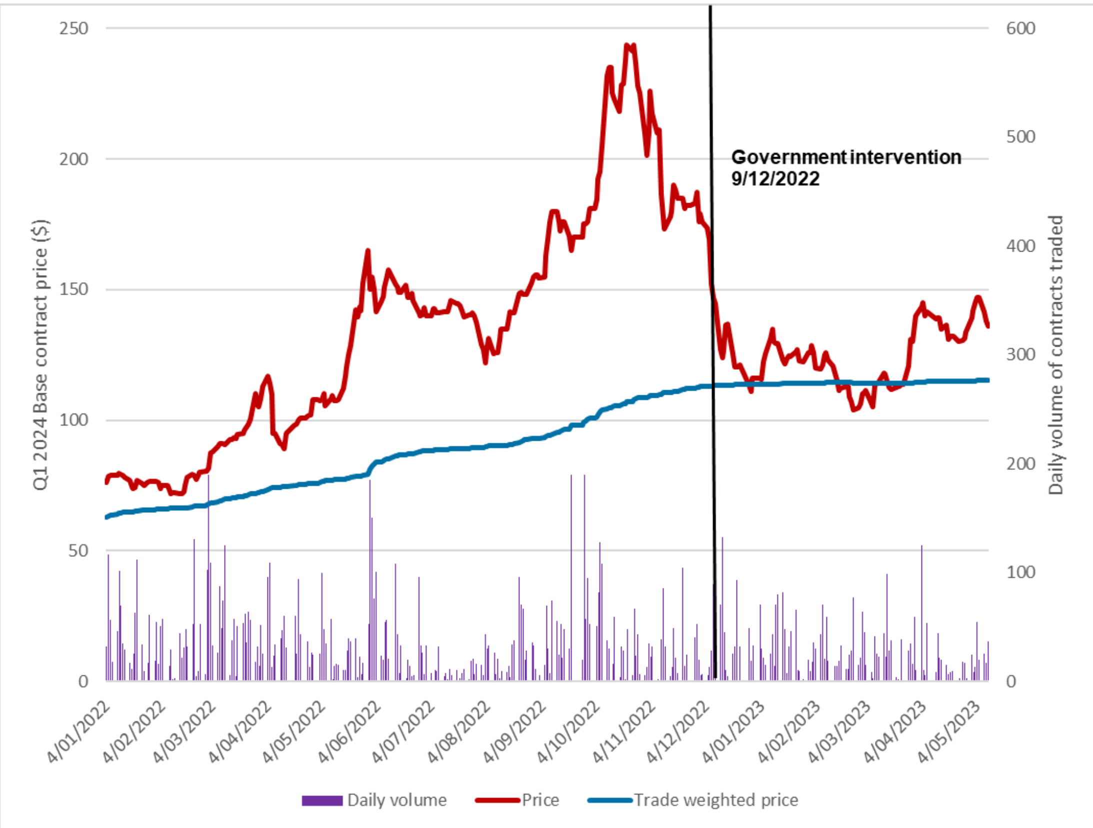
Figure 4.3 shows the movement of ASX base contracts for the summer quarter for 2023–24 (Q1 2024). Since the government intervention, contract prices have been lower, fluctuating between $105/MWh and $147/MWh. While the implementation of the price caps coincided with a decline in contract prices:

- contract prices remain elevated relative to their trading history (the red line in Figure 4.3)
- the trade-weighted contract price has continued to increase (the blue line in Figure 4.3).

As the trade-weighted contract price is a key input in determining wholesale energy costs, it is a key driver of the increases in electricity prices this year. These dynamics are illustrated below.

[79] In light of the limited information available at the time of the draft determination, the analysis assumed the price caps would apply uniformly to coal-fired power stations in New South Wales and Gladstone (i.e. those coal-fired generators exposed to the export coal market) and to all gas-fired power stations. However, the effects of the price caps on generator bidding have not been uniform across generators. For example, gas generators—and in particular peaking gas plants—rely to some extent on purchases of gas from short-term markets, which are exempt from the gas price cap (ACIL Allen, *Estimated Energy Costs*, final report, prepared for the QCA, May 2023, pp 35–38).

Figure 4.3 Queensland ASX base contracts for 2023–24 (Q1 2024)



Source: ASX Energy and QCA analysis.

Refinements

We made two methodological refinements to incorporate:

- ADM data, used to inform the forecast consumption (demand) profiles
- additional data, to more accurately estimate ASX contract prices.

Integration of ADM data

In past reviews, we did not use demand profiles of ADMs to inform our wholesale energy cost estimates due to the low penetration of ADMs. Also, further work was needed to obtain relevant information from AEMO and ensure it was appropriate (and robust) to use.[80]

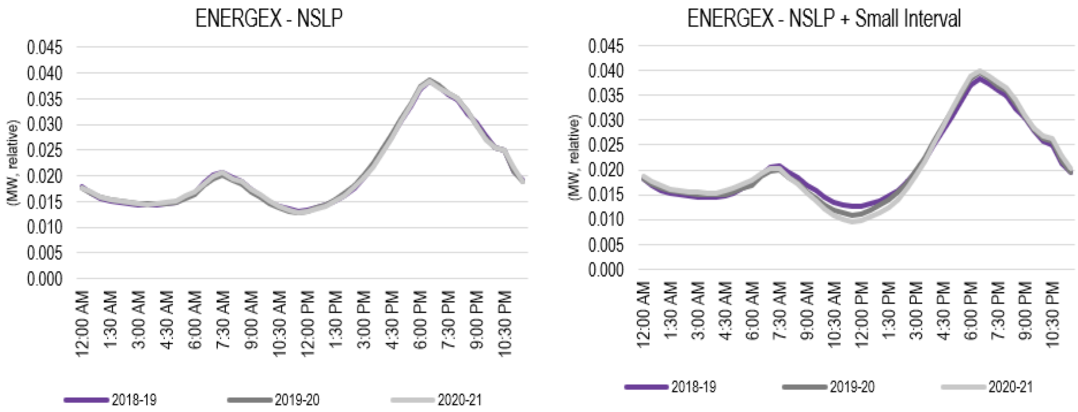
This year, we decided to incorporate ADM data, in combination with the relevant net system load profiles (NSLPs) and controlled load profiles (CLPs), to estimate wholesale energy costs.[81] Sufficient information has been obtained from AEMO, which our analysis indicates is reasonable to use. In particular, the ADM profile for small customers is 'peakier' than the NSLP[82] and shows a reduction in daytime demand due to increased rooftop solar PV penetration over time, as we would expect (see Figure 4.4).

[80] For example, see QCA, *Regulated retail electricity prices in regional Queensland 2022–23*, draft determination, February 2022, p 21.

[81] The NSLPs and CLPs are published by AEMO and are used to approximate the demand of customers on accumulation meters.

[82] On the other hand, the ADM profile of large customers is flatter than the NSLP, as large customers consume a greater proportion of their energy during the daytime.

Figure 4.4 Energex NSLP with ADM data



Source: ACIL Allen analysis of AEMO data - Figure 2.3 in ACIL's report

We consider this approach is appropriate, given the penetration of ADMs will continue to increase in Queensland.[83] Also, including ADM data now will ensure our estimates reflect the organic change in market information over time.[84] We also understand it reflects what retailers do in practice when developing their hedging strategies (i.e. retailers do not distinguish between customers with different meter types, but rather combine the profiles of ADMs and accumulation meters (for a specific customer group)).

ASX contract prices

When we estimate ASX contract prices, we also consider the cost retailers face to manage risk through call options.

In past reviews, we estimated ASX contract prices that incorporated call options (for base contracts) using a simplified approach, where options were approximated using the volume of options traded and ASX daily settlement prices for base contracts.

This year, given the recent market volatility, ACIL incorporated additional data on:

- strike prices of call options exercised
- premiums of call options exercised and expired
- trade volume of call options exercised and expired.[85]

[83] In this context, the Queensland Government's policy initiative is targeting 100 per cent penetration of ADMs by 2030 This issue is discussed in section 3.3.2. Further, the Power of Choice reforms implemented rule changes to facilitate deployment of ADMs across the NEM, including that all new and replacement meters for small customers be ADMs from 1 December 2017.

[84] It also reduces the potential risk of a 'step change' in prices if the ADM data is included all at once, when ADM penetration is higher. This risk is particularly relevant if the aggregate load profile of customers on ADMs is different to that of customers on the NSLP.

[85] ACIL Allen, *Estimated Energy Costs*, final report, prepared for the QCA, May 2023, pp 50–60.

Including this additional data accounts for:

- call options (not put options)[86], based on advice from ACIL. We consider this reasonable as unlike put options, call options allow retailers the opportunity to purchase more base contracts, in order to manage their spot price risk. Further, put options are not ordinarily used by retailers as part of hedging their retail load.[87]
- premiums of call options both exercised and expired, as retailers pay a premium to the seller of options, regardless of whether they choose to exercise the option.

We consider this approach better reflects the actual costs retailers incur in practice, by incorporating actual data on individual trades of contracts and base options.[88]

Time-varying wholesale energy costs

We have been asked to develop a methodology for setting the wholesale energy costs for the new time-of-use tariffs to provide greater price differentials between peak and non-peak periods (compared to the existing time-of-use tariffs 12B and 22B, on which the new retail tariffs will be based). This is intended to incentivise customers to use more electricity during non-peak periods (i.e. during daytime hours when network utilisation is low and solar PV generation is high).[89]

The methodology we developed to set the energy costs for the new retail tariffs involves:

- using the wholesale energy cost estimates for existing small customer tariffs 12B and 22B[90]
- deriving a set of weightings for different time periods based on the distribution of demand-weighted spot price variations throughout the day, which are typically lower during non-peak periods (i.e. daytime hours) compared to peak periods (i.e. evening hours)
- applying these weightings to the wholesale energy cost estimates (described above) to set rates that are lower during non-peak periods and higher during peak periods.[91]

This approach maintains the same level of wholesale energy costs (as tariffs 12B and 22B) but changes the way these costs are recovered throughout the day. This approach is likely to provide stronger price signals than the existing time-of-use tariffs and, as the Minister noted, could incentivise customers to take up electric vehicle charging during non-peak periods.

Table 4.1 sets out the components for the new tariffs, based on the methodology described above.

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[86] In this context, put options are a type of financial derivative that gives the holder the right, but not the obligation, to sell ASX base contracts at a predetermined price (i.e. strike price) and volume.

[87] Momentum Energy, submission to the AER, *Default market offer prices 2023–24* (draft decision), 5 April 2023, p 2; Energy Australia, submission to the AER, *Default market offer prices 2023–24* (draft decision), 6 April 2023, p 3.

[88] ACIL Allen, *Estimated Energy Costs*, final report, prepared for the QCA, May 2023, pp 50–60.

[89] For more details, see section 3.2.1.

[90] Consistent with EER's views, wholesale energy cost estimates for the new tariffs (like all other small customer tariffs), incorporate ADM data in combination with NSLP data.

[91] While stakeholders suggested further reductions in our off-peak rates to better reflect low-cost solar and wind power during the daytime, we consider weightings based on the spot price distribution adequately capture the impact of renewable generation in the NEM.

Table 4.1 Time-varying wholesale energy costs for the new time-of-use retail tariffs

Retail tariff	Period	c/kWh
Tariffs 12C and 22C (residential and small business time-of-use tariffs)	Peak (evening)	31.580
	Non-peak (day)	4.206
	Shoulder (night)	11.081

Note: For tariff 12C, peak usage is 4 pm to 9 pm; non-peak (day) usage is 9 am to 4 pm; shoulder (night) usage is all other times. For tariff 22C, peak usage is 4 pm to 9 pm weekdays; non-peak (day) usage is 9 am to 4 pm; and shoulder (night) usage is all other times.

Other energy costs and losses

Retailers incur other energy costs 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. The RET consists of the Large-scale Renewable Energy Target (LRET) and the Small-scale Renewable Energy Scheme (SRES)[92]
- NEM management fees and ancillary services charges—the costs levied by AEMO to cover the costs of operating the NEM and to manage power system safety, security and reliability
- Reliability and Emergency Reserve Trader (RERT) scheme charges—charges levied by AEMO to cover the costs of maintaining power system reliability and security, using reserve contracts. The RERT scheme allows AEMO to contract for emergency reserves, such as generation or demand response outside of the NEM
- prudential capital costs—the costs a retailer incurs to provide financial guarantees to AEMO and to lodge initial margins with the ASX for futures contracts.

Retailers also incur costs associated with:

- energy losses, as retailers purchase more electricity than customer demand to allow for the losses that occur when electricity is transported across the network
- significant market events that occur from time to time, such as the triggering of the administered price cap and suspension of the wholesale market by AEMO (from 12 to 24 June 2022).

[92] The LRET and SRES provide incentives for the electricity sector to increase generation from renewable sources and reduce greenhouse gas emissions. The costs of these incentives are paid by retailers through the purchase of large-scale generation certificates (LGCs) and small-scale technology certificates (STCs). LGCs or STCs can be created when eligible electricity is generated by utility-scale renewable generators or small-scale renewable systems.

Analysis and position

Our position is to estimate other energy costs based on ACIL's advice,[93] specifically:

RET costs	**Large-scale Renewable Energy Target (LRET) costs** These costs were 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 These costs were 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	These management fees were estimated based on the latest data from AEMO, including historical costs and projected changes in costs.
Ancillary services	These charges were estimated using the average historical costs observed over the preceding 52 weeks.
Prudential costs	These costs were estimated using AEMO's prudential requirements and margin requirements for trading in the ASX futures market.
RERT scheme charges	These charges were estimated using the historical costs published by AEMO for the preceding 52 weeks (excluding costs incurred in June 2022, see June 2022 events).
Energy losses	These losses have been estimated by applying transmission and distribution loss factors published by AEMO, in a manner that aligns with AEMO's settlement process.
June 2022 events	Costs associated with market events in June 2022 were estimated using the latest data from the AEMC and AEMO. These include the RERT costs and compensation costs published by the AEMC and AEMO to date.

We consider ACIL's estimates are appropriate and produce reliable estimates of the other energy costs likely to be incurred by retailers, including by using the latest relevant market data and information (i.e. from AEMO and the Clean Energy Regulator) to estimate each of the other energy cost categories.[94]

Consistent with EER's views, the estimates are forward-looking and include costs associated with the RERT and market events in June 2022, as provided for under the legislative framework.[95]

As the AEMC has finalised some, but not all, costs associated with the June 2022 market events, we have included the costs approved to date. Once the remaining costs are finalised, it would be appropriate to consider including them in notified prices in future.

Compared to the estimates from last year, our estimates of other energy costs are:

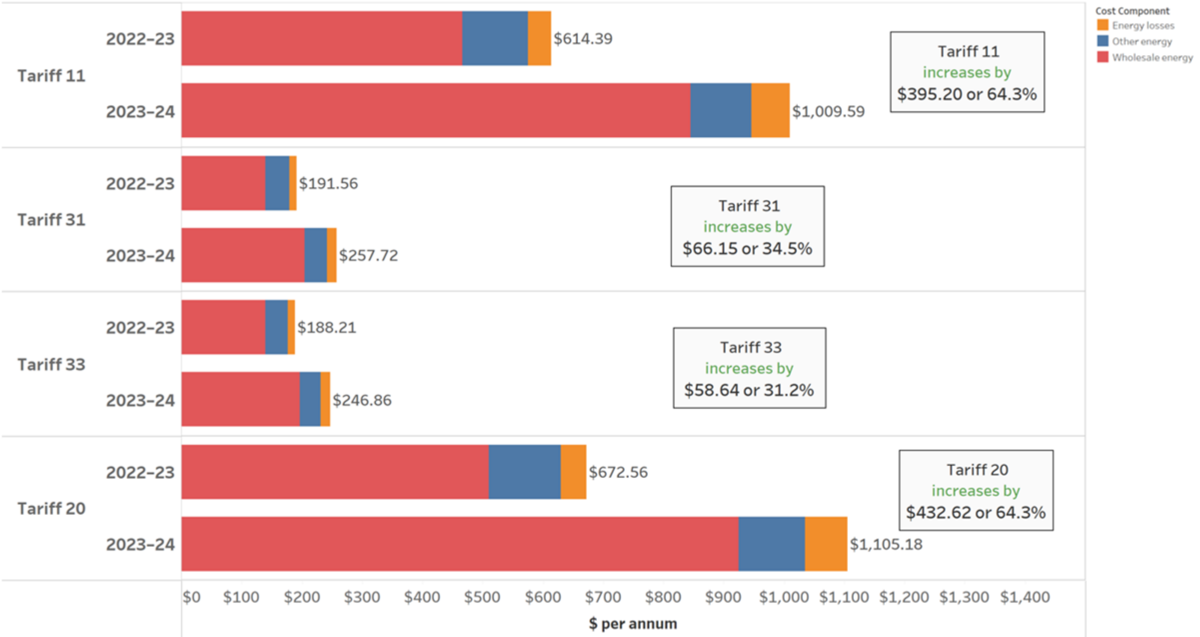
- 7 per cent ($1.54/MWh) lower for small customer tariffs
- 12.3 per cent ($2.66/MWh) lower for large customer tariffs.

[93] ACIL Allen, *Estimated Energy Costs*, final report, prepared for the QCA, May 2023, pp 63–71.
[94] Similarly, we have included energy losses based on AEMO's 2023–24 published loss factors (ACIL Allen, *Estimated Energy Costs*, final report, prepared for the QCA, May 2023, pp 32–33, 65–67).
[95] While WRIQ said the outstanding compensation amounts should be paid for by the Queensland Government (not users), these are legitimate costs retailers are entitled to recover under the National Electricity Rules (see the AEMC compensation guidelines for further information).

Total energy costs included in notified prices

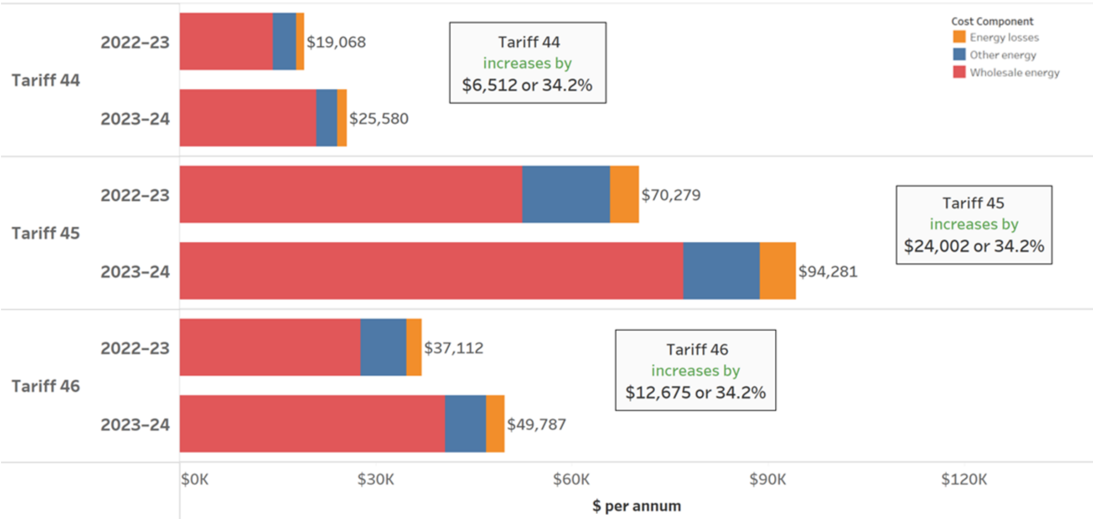
Overall, energy costs are estimated to increase for all customer groups, compared to last year's estimates. Figures 4.5 and 4.6 show the overall energy costs included in notified prices—compared to last year's estimates—by tariff type, for typical small and large customers.

Figure 4.5 Energy costs—typical customers on small customer tariffs (incl GST)



Note: The amounts in the figure are rounded. The percentage changes are based on unrounded amounts.

Figure 4.6 Energy costs—typical customers on large customer tariffs (incl GST)



Note: The amounts in the figure are rounded. The percentage changes are based on unrounded amounts.

4.2.2 Retail costs

Retail costs relate to the costs of running a retail electricity business and include:

- operating costs—the administrative costs of servicing existing customers and acquiring new customers (e.g. costs related to operating call centres, operating billing systems and collecting revenue)
- a retail margin—the return to investors for a retailer's exposure to systematic risk associated with providing retail electricity services.

The delegations do not specify any requirements for setting retail costs, except in relation to the metering costs for small customer tariffs (discussed in section 3.2.2).

In past determinations, we estimated retail costs by using established benchmark allowances, which we adjusted for inflation.[96] These were updated in the fulsome review of retail costs we did in the 2021–22 notified prices review,[97] where:

- for residential and small business customers—we established new retail costs (including fixed costs and cost allocators used to set the variable component of the retail cost allowances) to reflect up-to-date market information
- for large customers—we maintained the existing retail costs (including the fixed costs and cost allocators used to set the variable component of the retail cost allowances),[98] as there was insufficient evidence to vary the allowances for this customer class.

Stakeholder submissions

EER said we should incorporate costs associated with regulatory reform, resource challenges and heightened trading risks into the retail cost allowances. In particular, the reforms progressing in the NEM (driven by the Energy Security Board's NEM 2025 program) reflect a step change in costs driving system and resource investment, as demonstrated by AEMO's identification of this work program as a declared project. EER said it is also facing increasing compliance costs due to rule changes such as the AEMC's Family Violence rule change.[99]

Other stakeholders said it was unreasonable to include the costs associated with regulatory reforms and we should do an ex-post analysis of actual retailer costs to provide a benchmark for considering the effectiveness of the N+R framework.[100]

Analysis and position

Our position is to maintain the approach we used last year and set retail cost allowances by:

- adjusting last year's fixed retail costs (for residential, small business and large customers) for inflation to maintain the fixed retail costs in real terms[101]
- maintaining the variable retail cost allocators at:

[96] The benchmark retail cost allowances were first established in 2016–17.
[97] For more information, see Appendix C and ACIL's reports from our *2021–22 determination*.
[98] Except to adjust fixed costs for inflation.
[99] EER, sub 5, p 9.
[100] N Manson, sub 7, p 2; Canegrowers, sub 12, p 4.
[101] The small customer fixed costs were set in 2021–22. The large customer costs were established in 2016–17 and reviewed in 2021–22. The costs for both small and large customers have been adjusted for inflation each year since establishment. We applied the RBA's CPI forecast of 3.5% for 2023–24 (RBA, 'Economic Outlook', *Statement on Monetary Policy*, May 2023).

- 7.25 per cent for residential customers
- 18.7 per cent for small business customers
- 6.0445 per cent for large customers.[102]

This approach has also been applied to set retail costs for the two new retail tariffs.

Consistent with our requirements under the Electricity Act, we must have regard to the costs of supply.[103] The costs of running a retail business may be impacted by regulatory reform, among other things. We have considered EER's comments, but do not consider it appropriate to adjust retail costs at this time. There is no evidence to indicate that there will be a material incremental increase in retail costs in 2023–24 compared to 2022–23.[104]

More broadly, we recognise a number of changes are occurring across the NEM (including the reforms associated with the Energy Security Board's NEM 2025 program).[105] As these reforms progress, we acknowledge they may result in additional costs for retailers.

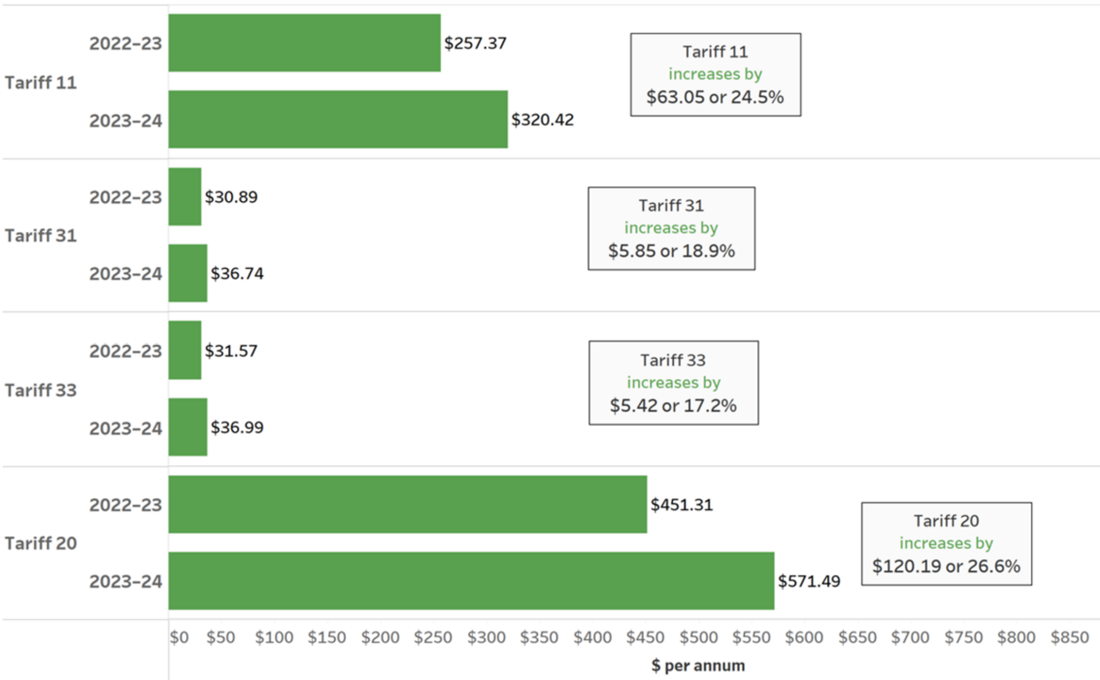
Given retail costs were subject to an in-depth review two years ago (in 2021–22), there may be merit in undertaking another review of retail costs in the near future. Such reviews have typically involved benchmarking analysis, considering the actual costs to supply small customers in SEQ.[106] This would allow us to consider not only potential costs associated with reforms and compliance, but also any savings to retail costs that may have occurred (for example, through productivity improvements).

Retail costs included in notified prices

Overall, retail costs have increased for small and large customers this year. Figures 4.7 and 4.8 show the retail costs included in notified prices—compared to last year's estimates—by tariff type for typical small and large customers. The retail costs for small customer tariffs include the cost of metering services set out in section 3.2.2.

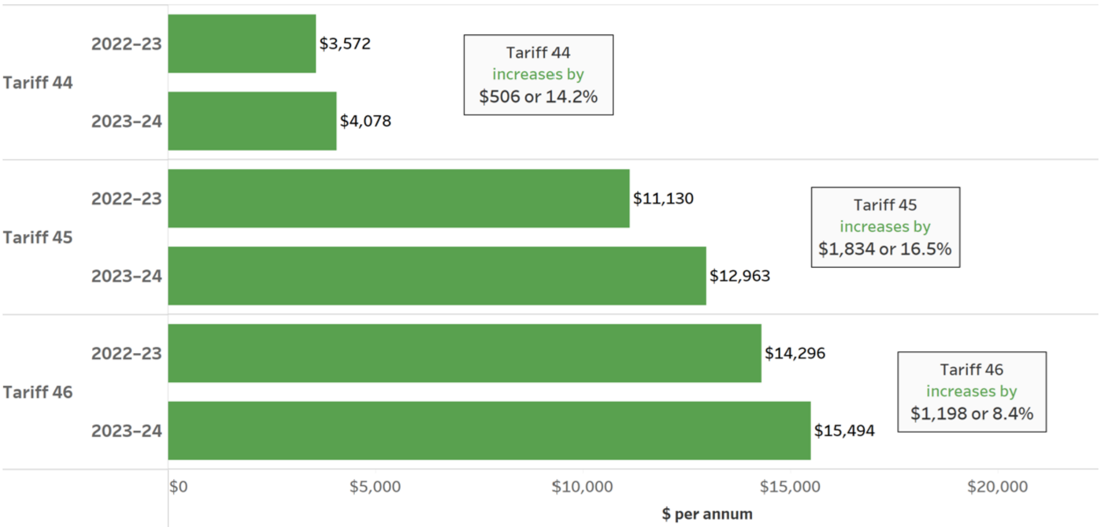
[102] The small customer variable cost allocators were set in 2021–22. The large customer allocator was established in 2016–17 and reviewed in 2021–22.
[103] Electricity Act, s. 90(5)(a)(i).
[104] While AEMO determined the Energy Security Board's NEM 2025 program to be a declared project, this does not identify the scale of costs that retailers may incur, nor demonstrate an incremental increase to retail costs overall.
[105] We understand that while some reforms have already been implemented, or are due for implementation shortly, a degree of uncertainty remains around the implementation and timing of others.
[106] Benchmarking analysis has also been conducted for large customer retail allowances, though this was based on allowances in other regulatory decisions and other information available to us.

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



Note: Includes small customer metering costs to facilitate a like-for-like comparison. The amounts in the figure are rounded. The percentage changes are based on unrounded amounts.

Figure 4.8 Retail costs—typical customers on large customer tariffs (incl GST)



Note: The amounts in the figure are rounded. The percentage changes are based on unrounded amounts.

5 OTHER COSTS AND PRICING MATTERS

This chapter sets out our positions on other costs and pricing matters, including adjustments we need to consider when setting notified prices this year. The matters discussed are:

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

5.1 Standing offer adjustment—small customers

Similar to previous years, the Minister asked us to consider the costs and benefits associated with standing offers in SEQ as well as the AER's default market offer (DMO) for SEQ (given the Queensland Government's UTP) when setting notified prices for small customers.[107]

In previous determinations, such considerations have led us to:

- incorporate a standing offer adjustment (SOA) in notified prices for small customers, to reflect the value of more favourable terms and conditions in standard contracts relative to market contracts
- compare the relevant notified price bills (including a SOA) to the DMO reference bills for SEQ and consider reducing the value of the SOA if the notified price bill exceeds the DMO reference bill, provided the value of the SOA is not reduced below zero (the DMO comparison).

Last year, we applied a SOA of 3.7 per cent (of total costs) based on an assessment of the potential fees incurred by small customers on market contracts in SEQ. These fees served as a proxy for the value of the SOA, as they represented the costs that customers could avoid by being on a standard contract relative to a market contract. No adjustment to the SOA was necessary, as the relevant notified price bills did not exceed the DMO bills.[108]

This year, we have adopted the same approach to setting the SOA, including undertaking the DMO comparison to assess whether the SOA needs to be reduced.

Stakeholder submissions

Stakeholders did not comment on the value of the SOA, but said:

- using the DMO to inform the SOA may not provide adequate price protections for customers because of the different environment in regional Queensland (e.g. customers cannot shop around for a retailer) and several broader issues identified with the DMO's effectiveness and calculation[109]
- in the event adjustments to the SOA are required (relating to the DMO comparison), we should provide details on the method and calculations.[110]

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[107] Appendix A: Minister's delegation for notified prices, cover letter.
[108] QCA, *Regulated retail electricity prices in regional Queensland 2022–23*, final determination, May 2022, pp 52–55.
[109] WRIQ, sub 9, pp 4–6.
[110] QFF, sub 6, p 3.

Analysis and position

Having regard to relevant matters, stakeholder comments and our own analysis, we consider it appropriate to incorporate a SOA into small customer notified prices, but at a discounted value based on the results of the DMO comparison.

SOA value

To determine the value of the SOA, we used the same approach as last year, updated it to reflect more recent market data. Using 2021–22 market data,[111] we:

- assessed the range of fees and charges attached to retail market contracts
- identified any additional fees in market contracts compared with standard contracts
- determined the potential fees that small customers in SEQ on market contracts could incur annually (that would not be incurred on a standard contract).

Based on our assessment, small customers on market contracts in SEQ could incur, on average, around $59 in additional fees (on top of their annual bill). This equates to around 4.56 per cent of a small customer's annual electricity bill.

Consistent with last year, we consider 4.56 per cent (of total costs) is an appropriate proxy for the value of the SOA, reflecting the costs small customers avoid by being on standard contract terms and conditions relative to a market contract.

Further details on our approach to setting the SOA is provided in Appendix C.

DMO comparison

To undertake the DMO comparison, we used the same approach as last year, updated to take account of the 2023–24 DMO reference bills for SEQ approved by the AER.[112] We:

- made some adjustments to better compare the DMO bills and relevant notified price bills (detailed in Appendix C)
- compared the relevant notified price bills (including the 4.56 per cent SOA) with the DMO reference bills for SEQ.

Based on the comparison, we found all relevant notified prices bills exceeded the DMO reference bills. Further details on our assessment and comparison are provided in Appendix C.

On this basis, we consider it is appropriate to:

- discount the value of the SOA incorporated into small customer notified prices (provided that the value is not discounted below zero)
- based on previous guidance from the Minister, consider discounting the value of the SOA in a way that maintains the price relativity of small customer tariffs, including tariffs of the same type (primary or secondary) within a customer class (residential or small business).[113]

Accordingly, we have reduced the SOA for:

[111] This data reflects our most recent review of retail fees (QCA, *SEQ retail electricity market monitoring 2021–22*, December 2022, pp 60–65, 67–72).
[112] AER, *Default market offer prices 2023–24*, final determination, May 2023, p. 66.
[113] Queensland Government, *Electricity (Ministerial—QCA) delegation (no 3) 2020*, January 2021, terms of reference, cl. 2(a) and (b).

- all residential customer tariffs[114]—from 4.56 per cent to zero (reflecting the reduction required for tariff 11)[115]
- all small business tariffs—from 4.56 per cent to zero (reflecting the reduction required for tariff 20).[116]

We consider our approach to be appropriate in this instance. It reflects the results of the DMO comparison and is consistent with the requirements in the delegation. As this is primarily a mechanism to ensure consistency with the UTP, stakeholder concerns relating to how the DMO is calculated and its effectiveness are not factors relevant to our review (and should be raised with the AER).

Our approach also ensures that price relativity is maintained within a customer class (residential or small business), which is important, based on prior guidance from the Minister. Maintaining price relativity is a matter that we considered broadly in the past following the guidance from the Minister but never had to apply (i.e. in recent determinations, notified price bills have not exceeded the DMO bills for SEQ).

Maintaining price relativity avoids some tariffs becoming more attractive than others solely by virtue of those tariffs having a reduced SOA. This could potentially distort a customer's preference for different tariff options. Further, without the benefit of additional consultation (which is not possible given our review timeframes), we consider it appropriate that all customers within the same customer class benefit from a reduction in the SOA.

Should we need to reduce the SOA in the future, we could revisit our approach, taking into account further information (e.g. guidance from the Minister and stakeholder views).

5.2 Cost pass-through mechanism

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

Consistent with our approach in previous determinations, we have provided for the pass-through of Small-Scale Renewable Energy Scheme (SRES) costs in the notified prices this year.

SRES cost pass-through

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

Generally, at the time of our final determination for notified prices, only the SRES liabilities for the first half of the financial year are known, while liabilities for the second half are based on the forecasts from the CER. The CER typically determines the final SRES liabilities for the second half of the financial year about nine months after our final determination. If there are discrepancies between the CER's forecast and its final determination of the SRES liabilities, it can lead to an over- or under-recovery of SRES costs.

[114] Including load control tariffs 31 and 33.

[115] We have applied the reduction required for residential flat-rate tariff 11 (rather than the flat-rate with load control tariff or time-of-use tariff) on the basis that tariff 11 is the most widely used residential tariff.

[116] Further information on our approach to the DMO comparison and reducing the SOA is provided in Appendix C.

Analysis and position

We used the CER's SRES liabilities for 2023, as reflected in its most recent decision, which results in lower-than-expected SRES liabilities for 2022–23. This means retailers were required to purchase fewer certificates to surrender to the CER than initially forecast—leading to an over-recovery of SRES costs for 2022–23 and a decrease in usage charges for all retail tariffs for 2023–24.[117]

Our position is to incorporate the over-recovery of SRES costs in 2023–24 notified prices. We consider this to be appropriate, given that it aligns notified prices with the UTP-consistent costs of supply.

The pass-through provisions discussed here may, or may not, remain appropriate in the future, depending on the regulatory framework for future price determinations and whether changes are made to the UTP. Therefore, we cannot commit to the continued availability of a cost pass-through mechanism beyond this price determination.

5.3 Metering costs—large customers

We did not receive submissions on large customer metering. We consider it appropriate to maintain our current approach of:

- separating the large customer metering costs for ADMs from retail costs and estimating these metering charges separately
- estimating metering charges based on confidential data provided by retailers, averaged to produce cost estimates for each large customer type.

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

5.4 Additional issues raised by stakeholders

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

Table 5.1 Additional issues raised in stakeholder submissions

Issues	Our response
Scope of review and consultation Cotton Australia raised concerns with what it considered to be a regimented approach to price setting and lack of willingness to provide public advice to the government on how tariffs and associated issues such as equal access can be improved.[118] Canegrowers was similarly frustrated by engaging in a process where the QCA has limited powers over the underlying policies that govern the pricing mechanism that it administers. Canegrowers said it would continue to engage to include its views on the public record and ensure growers' concerns are heard.[119]	We perform our role in accordance with the requirements of the Electricity Act and the terms of the Minister's delegation(s). If stakeholders consider the scope of our review (as set by the delegations) should be expanded to investigate or provide advice on particular policy issues, stakeholders should engage with the Queensland Government before a future notified prices review. Consultation is an integral part of our decision-making process, and we invite all stakeholders, including members of the community, to participate in our reviews. Our process includes the publication of an interim consultation paper and a draft determination, providing transparency around our intended

[117] See Appendix D for further detail on how we estimated the SRES cost pass-through.
[118] Cotton Australia, sub 1, p 1.
[119] Canegrowers, sub 12, p 1.

QFF said our framework does not allow for meaningful consultation, including to consider issues and solutions provided.[120] Both QFF and Canegrowers said we should seek a direction to extend the scope of our review for further consultation with stakeholders.[121] QFF sought transparency around calculations and pre-emptive communication of proposed changes.[122]	approach to setting notified prices and allowing stakeholders the opportunity to comment. This year, we also held a number of information sessions on our draft determination across regional Queensland, in Brisbane and online, where stakeholders were able to ask questions and gain further clarity on our draft positions before making submissions. We have considered stakeholder submissions and provided responses throughout this final determination.
Policy matters Stakeholders raised concerns in relation to a number of policy matters, including: • the N+R methodology—QFF said the pricing methodology is outdated and changes are required, which should be addressed as part of a separate delegation. This includes further investigation of the cost build-up components utilised for the delivery of electricity.[123] • payment of the CSO—Several stakeholders said this should be paid to Ergon Network, rather than to Ergon Energy Retail.[124] Stakeholders said this would support the development of retail competition, as well as bring the possibility of microgrids a step closer to being a feasible opportunity.[125] • customer consumption threshold levels—QFF and Canegrowers said there should be an increase to the small customer threshold.[126] Canegrowers said this would support users who were on obsolete tariffs (tariffs 62, 65 and 66) and were unable to access the new transitional retail tariffs (limited access obsolete tariffs 62A, 65A and 66A) or other small business tariffs.[127] • recovery of costs associated with the solar bonus scheme and RERT—several stakeholders said these should be met by a separate CSO, funded by the government.[128] • supply of electricity—PVW said the co-gen unit at Mackay Sugar Racecourse Mill could be used to provide fixed-rate electricity to cane growers in the Pioneer Valley.[129]	Stakeholders commented on a range of matters that go beyond the scope of our review. The scope of our review is set out in section 1.2 and is bound by the framework in which we operate and set notified prices. Being delegated the task of setting notified prices by the Minister does not unlock investigative and decision-making powers for us to assess all concerns stakeholders raise, or implement measures proposed by stakeholders aimed at addressing these concerns. These concerns arise in connection with the development and operation of the overarching framework (legislation and policy), rather than how a particular task is performed within this framework (our role in setting notified prices). In relation to stakeholders' proposed approaches to pricing, we are required to consider using an N+R approach. Under this framework, prices are determined based on AER-approved network costs and observed market data for the retail component. Setting ceilings or charging customers on a sliding scale would not be consistent with the N+R approach and the Queensland Government's UTP (section 3.1).

[120] QFF, sub 6, p 3, sub 10, p 3.
[121] QFF, sub 6, p 3, sub 10, p 3; Canegrowers, sub 12, pp 1–2.
[122] QFF, sub 6, p 5.
[123] QFF, sub 6, p 5, sub 10, p 5.
[124] BRIG, sub 2, p 2; QFF, sub 6, p 2, sub 10, p 3; WRIQ, sub 9, p 7; Canegrowers, sub 12, p 4.
[125] Canegrowers, sub 12, p 4.
[126] QFF, sub 6, p 5; Canegrowers, sub 12, p 3.
[127] Canegrowers, sub 12, p 3.
[128] BRIG, sub 2, pp 2–3; WRIQ, sub 9, p 7; Cotton Australia, sub 11, p 1.
[129] PVW, sub 4, p 1.

• power station turbines—one view was that these should run on gas instead of coal to reduce tonnes of pollution.[130] Stakeholders said an affordable tariff would have a price ceiling of 16 c/kWh, based on network costs and retail costs each not exceeding 8 c/kWh.[131] Another recommendation was for large customers to be charged on a sliding scale, directly correlated to profit margins.[132]	
Pricing matters QFF requested that an investigation be undertaken on the potential for tariff 22B to become a solar-soaker tariff for small business customers and irrigators.[133]	In section 3.2.1, we discuss the two new retail tariffs we developed, including one based on tariff 22B for small business customers. In relation to QFF's comment regarding solar-soaker tariffs, the delegation requires us to set a new retail tariff based on tariff 22B. This new tariff will operate as a solar-soaker tariff, available to small business customers.
Access to dynamic load control tariffs Cotton Australia said irrigators in St George should be provided access to tariffs 60A and 60B, stating they face a considerable disadvantage compared with their peers across the state.[134]	Access to tariffs 60A and 60B requires network signalling equipment to be installed. This equipment allows the distributor to control the energy supply. While we understand stakeholders' desire for these tariffs to be available in all areas, we cannot direct distributors to install or offer tariffs with different signalling technology, as network infrastructure and investment are matters for the distributor. We encourage customers to engage with their retailer about options for tariffs that would meet their circumstances.
Global settlement charges WRIQ queried the impact of AEMO's global settlements charges on our notified prices.[135]	With the introduction of global settlements, there have been changes to the billing of unaccounted-for energy. All retailers are now allocated a proportion.[136] This is a matter of how existing costs are being allocated, and it is not considered in our review, as these charges are not new costs to all retailers.

Sources: Submissions on the consultation paper (ICP) and our draft determination, published on the QCA website; QCA analysis.

[130] B Leaver, sub 14, p 1.
[131] BRIG, sub 2, p 1; PVW, sub 4, p 1; QFF, sub 6, p 2, sub 10, p 2; Canegrowers, sub 12, p 2.
[132] N Manson, sub 7, p 1.
[133] QFF, sub 6, p 4.
[134] Cotton Australia, sub 11, p. 1.
[135] WRIQ, sub 9, p 7.
[136] Some examples of unaccounted-for energy include electrical losses, unmetered loads and estimation errors. For further details on global settlements, refer to AEMO, *What is Global Settlement?*, fact sheet, July 2020.

6 NOTIFIED PRICES

This chapter sets out the notified prices for 2023–24. A breakdown of the notified prices by cost component is provided in Appendix F. 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 G.

Table 6.1 Notified prices—residential customers, 2023–24 (excl GST)

Retail tariff	Fixed [a]	Usage			Demand
		Off-peak/ flat	Shoulder	Peak	
	c/day	c/kWh	c/kWh	c/kWh	$/kW/month
Tariff 11—residential (flat-rate)	109.521	30.227			
Tariff 12B—residential time-of-use [b]	107.721	24.793	25.515	38.839	
Tariff 12C—residential time-of-use [b]	107.721	9.924	18.521	55.325	
Tariff 14A—residential time-of-use demand [c]	107.721	25.265			4.518
Tariff 14B—residential time-of-use demand [c]	107.721	24.227			8.511
Tariff 31—night rate (super economy)	3.385	18.971			
Tariff 33—controlled supply (economy)	3.385	20.510			

a Charged per metering point.
b Peak usage: 4 pm to 9 pm; shoulder (night) usage: all other times; off-peak (day) usage: 9 am to 4 pm.
c Demand: 4 pm to 9 pm all days.

Table 6.2 Notified prices—small business and unmetered supply customers, 2023–24 (excl GST)

Retail tariff	Fixed [a]	Usage		Demand
		Off-peak/ flat	Peak	
	c/day	c/kWh	c/kWh	$/kW/month
Tariff 20—business (flat-rate)	142.180	34.319		
Tariff 24A—business (time-of-use demand) [b]	140.280	30.700		4.839
Tariff 24B—business (time-of-use demand) [b]	140.280	29.568		11.011
Tariff 34—business (interruptible supply)	130.880	23.528		
Tariff 91—unmetered		31.628		

a Charged per metering point.
b Demand: 4 pm to 9 pm on weekdays.

Table 6.3 Notified prices—small business customers, 2023–24 (excl GST)

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 22B—small business time-of-use inclining band [b]	140.280	169.780	199.480	229.280	258.980	27.331	33.373	45.590
Tariff 22C - small business time- of-use inclining band [b]	140.280	169.780	199.480	229.280	258.980	10.875	25.632	63.837

a Fixed band 1: 0 MWh to 20 MWh annual consumption; fixed band 2: 20 MWh to 40 MWh annual consumption; fixed band 3: 40 MWh to 60 MWh annual consumption; fixed band 4: 60 MWh to 80 MWh annual consumption; fixed band 5: 80 MWh and above annual consumption.
b Peak usage: 4 pm to 9 pm 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, 2023–24 (excl GST)

Retail tariff	Fixed	Usage		Demand		Excess demand
		Off-peak/flat	Peak	Off-peak/flat[a]	Off-peak/flat[a]	
	c/day	c/kWh	c/kWh	$/kW/month	$/kVA/month	$/kVA/month
Tariff 44—over 100 MWh small (demand)	4278.095	18.701		26.349	23.713	
Tariff 45—over 100 MWh medium (demand)	13709.049	18.701		26.349	23.713	
Tariff 46—over 100 MWh large (demand)	35679.064	18.701		21.227	19.115	
Tariff 50A—large business time-of-use demand[b]	17575.145	18.756			16.642	2.547
Tariff 60A—large business flat-rate interruptible supply (primary)	4278.095	24.775				
Tariff 60B—large business flat-rate interruptible supply (secondary)		24.775				
Tariff 71—street lighting		29.198				

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 Demand: 4 pm to 9 pm weekdays.

Table 6.5 Notified prices—very large business customers, 2023–24 (excl GST)

Retail tariff	Fixed	Usage	Connection unit	Capacity	Demand
	c/day	c/kWh	$/day/unit	$/kVA of AD/month	$/kVA/ month
Tariff 51A—high voltage (CAC 66 kV)	23347.335	14.375	6.586	3.603	3.888
Tariff 51B—high voltage (CAC 33 kV)	17058.535	14.375	6.586	4.376	4.028
Tariff 51C—high voltage (CAC 22/11 kV Bus)	15969.235	14.375	6.586	5.029	4.883
Tariff 51D—high voltage (CAC 22/11 kV Line)	15346.835	14.375	6.586	9.642	9.849
Tariff 53—high voltage (ICC)	23146.835	14.375		3.603	3.888
ICC site-specific—high voltage	2700.835	12.685		0.205	0.222

Table 6.6 Notified prices—very large business customers, 2023–24 (excl GST)

Retail tariff	Fixed	Usage		Connection unit	Capacity	Demand
		Off-peak	Peak			
	c/day	c/kWh	c/kWh	$/day/unit	$/kVA of AD/month	$/kVA/ month
Tariff 52A—high voltage (CAC STOUD 33–66 kV)	12779.135	16.125	13.815	6.586	6.434	15.128
Tariff 52B—high voltage (CAC STOUD 22/11 kV Bus)	12779.135	16.125	13.815	6.586	4.568	50.542
Tariff 52C—high voltage (CAC STOUD 22/11 kV Line)	12779.135	16.125	13.815	6.586	8.299	69.021

Table 6.7 Notified prices—large business customers, 2023–24 (excl GST)

Retail tariff	Fixed	Usage [a]	
		Below threshold	Above threshold
	c/day	c/kWh	c/kWh
Tariff 43—Business customer (over 100 MWh)	4278.095	19.056	27.940

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, 2023–24 (excl GST)

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]	110.286	69.027	58.562	25.203		
Tariff 65A—time-of-use tariff[b]	109.886	55.144		30.924		
Tariff 66A—dual-rate demand tariff[c]	242.186			29.433	4.530	13.675

a Block 1: 7 am to 9 pm 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 7 am to 7 pm, 7.30 am to 7.30 pm, or 8 am to 8 pm; 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, 2023–24 (excl GST)

Retail tariff	Fixed	Usage		Demand	
		Off-peak/flat	Peak	Off-peak/flat	Peak[a]
	c/day	c/kWh	c/kWh	$/kW/month	$/kW/month
Tariff 50—over 100 MWh seasonal time-of-use (demand)	3715.245	21.084	17.499	11.754	77.338

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

Table 6.10 Metering charges—large and very large business customers advanced meters, 2023–24 (excl GST)

Customer type	Metering charge
	c/day
Standard asset customer (annual usage of 750 MWh or less)	216.940
Standard asset customer (annual usage greater than 750 MWh)	260.421
Connection asset customer	429.295
Individually calculated customer	375.281

Source: Retailer data.

GLOSSARY

ACCC	Australian Competition and Consumer Commission
ACIL	ACIL Allen
AD	Authorised demand
ADM	Advanced digital meter
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
ASX	Australian Securities Exchange Ltd
BRIG	Bundaberg Regional Irrigators Group
CER	Clean Energy Regulator
CLP	Control load profile
CPI	Consumer price index
CSO	Community service obligation
Delegation(s)	The delegation(s) issued by the Minister for Energy, Renewables and Hydrogen (see Appendix A)
DMO	Default market offer
EER	Ergon Energy Retail
Electricity Act	*Electricity Act 1994* (Qld)
Electricity Regulation	Electricity Regulation 2006
Energex	Energex Distribution
EQ	Energy Queensland
Ergon Distribution	Ergon Energy Corporation Limited (electricity distribution arm)
ESOO	Electricity Statement of Opportunities
EV	Electric vehicle
FCAS	Frequency control ancillary services
GJ	Gigajoule
GST	Goods and services tax
Human Rights Act	*Human Rights Act 2019* (Qld)
ICE	Intercontinental Exchange
ICP	Interim consultation paper
ISP	Integrated System Plan
kVA	Kilovolt amperes
kW	Kilowatts

kWh	Kilowatt hour
LGC	Large-scale generation certificate
LNG	Liquefied natural gas
LOR 2	Lack of Reserve 2
LRET	Large-scale renewable energy target
Minister	Minister for Energy, Renewables and Hydrogen
MT–PASA	Medium-term projected assessment of system adequacy
MW	Megawatt
MWh	Megawatt hour
N	Network costs
NECF	National Energy Customer Framework
NEM	National Electricity Market
NER	National Electricity Rules
NERL	National Energy Retail Law
NMI	National meter identifier
Notified prices	Regulated retail electricity prices
NSLP	Net system load profile
N+R	Network + retail cost build-up methodology
OTC	Over-the-counter
POE	Probability of exceedance
PPAs	Power purchase agreements
PV	Photovoltaic
PVW	Pioneer Valley Water Co-operative Limited
QCA	Queensland Competition Authority
QFF	Queensland Farmers' Federation
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 Customers
SBS	Solar Bonus Scheme
SEQ	South east Queensland
SOA	Standing offer adjustment

SRES	Small-scale renewable energy scheme
STC	Small-scale technology certificate
STP	Small-scale technology percentage
TOU	Time-of-use
UTP	Uniform Tariff Policy
WRIQ	Waste and Recycling Industry of Queensland
$/t	Dollars per tonne
$/GJ	Dollars per gigajoule

STAKEHOLDER SUBMISSIONS AND REFERENCES

Stakeholder submissions

We received 14 submissions during our review, which are available on our website.

Stakeholder	Submission number	Date received
Bundaberg Regional Irrigators Group (BRIG)	2	17 January 2023
Cotton Australia	1	11 January 2023
	11	14 April 2023
Canegrowers	12	14 April 2023
Ergon Energy Corporation Limited and Energex Limited (Ergon Energy Network and Energex)	3	18 January 2023
Ergon Energy Retail (EER)	5	19 January 2023
	13	17 April 2023
Leaver, B	14	22 April 2023
Manson, N	7	17 March 2023
Pioneer Valley Water Co-operative Limited (PVW)	4	18 January 2023
Pownall, J	8	3 April 2023
Queensland Farmers' Federation (QFF)	6	19 January 2023
	10	14 April 2023
Waste and Recycling Industry of Queensland (WRIQ)	9	6 April 2023

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