Queensland Competition Authority

Regulated retail electricity prices 2025-26

Final determination

June 2025

Contents

1 About our review

Each year, we set regulated retail electricity prices for regional Queensland.

In December 2024, the Treasurer, Minister for Energy and Minister for Home Ownership (the Minister) delegated us the task of setting regulated retail electricity prices (notified prices) for regional Queensland in 2025–26.[1]

We set notified prices using a well-established framework, based on factors in the Electricity Act and matters in the delegation (Box 1), stakeholder submissions and our own analysis.

This final determination includes notified prices to apply from 1 July 2025.

Box 1: Overarching framework

When setting notified prices, the Electricity Act requires us to have regard to:

- 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.

The Minister's delegation (and terms of reference) specifies policies, principles and other matters we must consider this year, such as:

- using the network plus retail (N+R) cost build-up methodology to set notified prices – this involves passing through network prices (approved by the Australian Energy Regulator (AER)) and adding retail and energy costs (which we determine)
- the Queensland Government's uniform tariff policy (UTP) – this ensures that, where possible, customers within the same class pay no more for their electricity, and can access similar pricing structures, regardless of their location. As a result, for most customers, prices are set below the actual cost of supply and are subsidised by the Queensland Government through a community service obligation payment.

1.1 Final determination

This year, customers can expect an increase in their electricity bills – largely due to an increase in network costs, which is partially offset by a decrease in energy costs.

The notified prices are bundled prices that reflect the retail tariff structure (except for site-specific tariffs). We also draw stakeholders' attention to the changes to the existing suite of retail tariffs

[1] The delegation was issued in accordance with s 90AA of the *Electricity Act 1994* (Qld).

necessary to reflect the changes in underlying network prices expected from 1 July 2025 (see section 3.1).

We are now at the final stage of this year's notified prices review (Figure 1.1).

Figure 1.1: Stages of the review

1.2 Supporting information

Supporting information available on our website includes:

- appendices to this report:
  - Appendix A: Network tariff changes
  - Appendix B: N component indexation approach
  - Appendix C: SRES cost pass-through approach
  - Appendix D: Data used to estimate customer impacts
  - Appendix E: Build-up of draft notified prices
  - Appendix F: Draft gazette notice
- the Minister's delegation and terms of reference
- an information booklet summarising our determination
- a notified prices bill calculator
- an energy costs report prepared by our consultant ACIL Allen (ACIL).

1.3 Human Rights Act declaration

While our decision is economic in nature, the *Human Rights Act* (Qld) requires us to consider human rights that may be affected by our determination of notified prices. We consider that our decision does not give rise to a limitation of any right under the Human Rights Act.

2 Customer bills

Overall, we forecast an increase in the underlying cost of supplying energy to most customers – which is reflected in the notified prices.

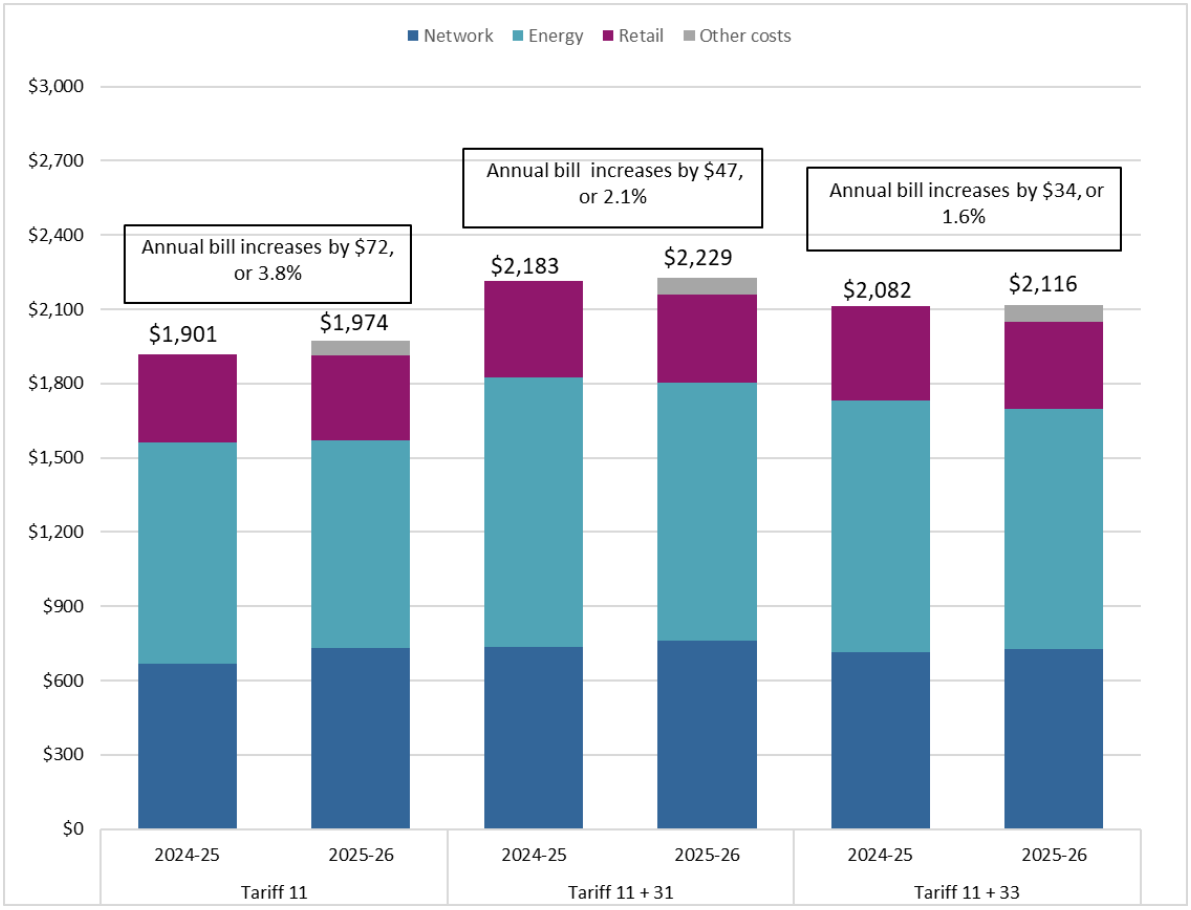
These bill estimates are for general guidance only. Actual bills will vary based on individual electricity use. For personalised advice or further information, customers should contact their retailer.[2]

2.1 Small customer bills

Residential customers

Typical customers on the main residential tariff (tariff 11) are expected to pay around 3.8% more for electricity in 2025–26 (Figure 2.1). However, customers also on secondary load control tariffs (tariffs 31 and 33) may see some offset, as those tariffs are expected to decrease.

Figure 2.1: Residential customer bills, 2024–25 and 2025–26 (incl GST)



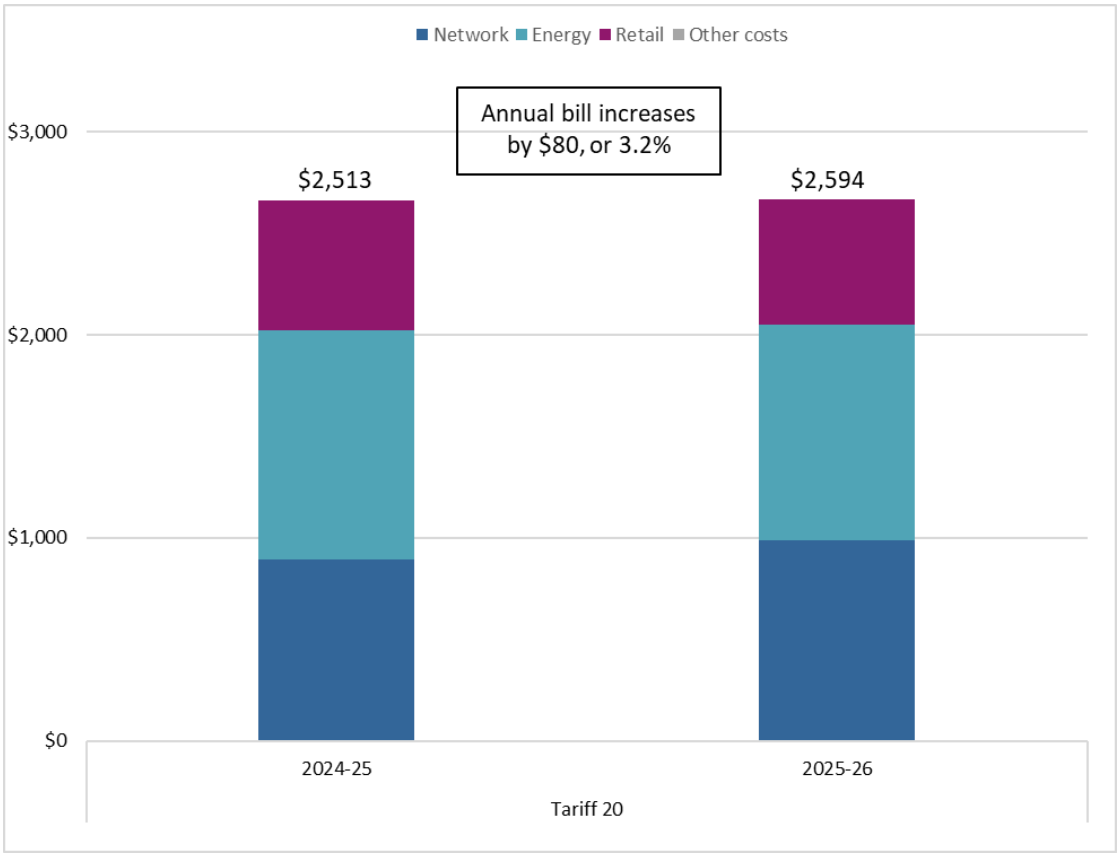
Note: As other costs for residential customers are negative in 2024–25, they do not appear in the figure above.

[2] The bills are calculated based on the consumption of a typical customer – that is, the median (middle) customer in terms of consumption among all customers in regional Queensland on the same tariff (see Appendix D).

Small business customers

Typical customers on the main small business tariff (tariff 20) are expected to pay around 3.2% more for electricity in 2025–26 (Figure 2.2). However, customers also on secondary load control tariffs (tariffs 31 and 33) may see some offset, as those tariffs are expected to decrease.

Figure 2.2: Small business customer bills, 2024–25 and 2025–26 (incl GST)



Note: As other costs for small business customers are negative in 2024–25 and 2025–26, they do not appear in the figure above.

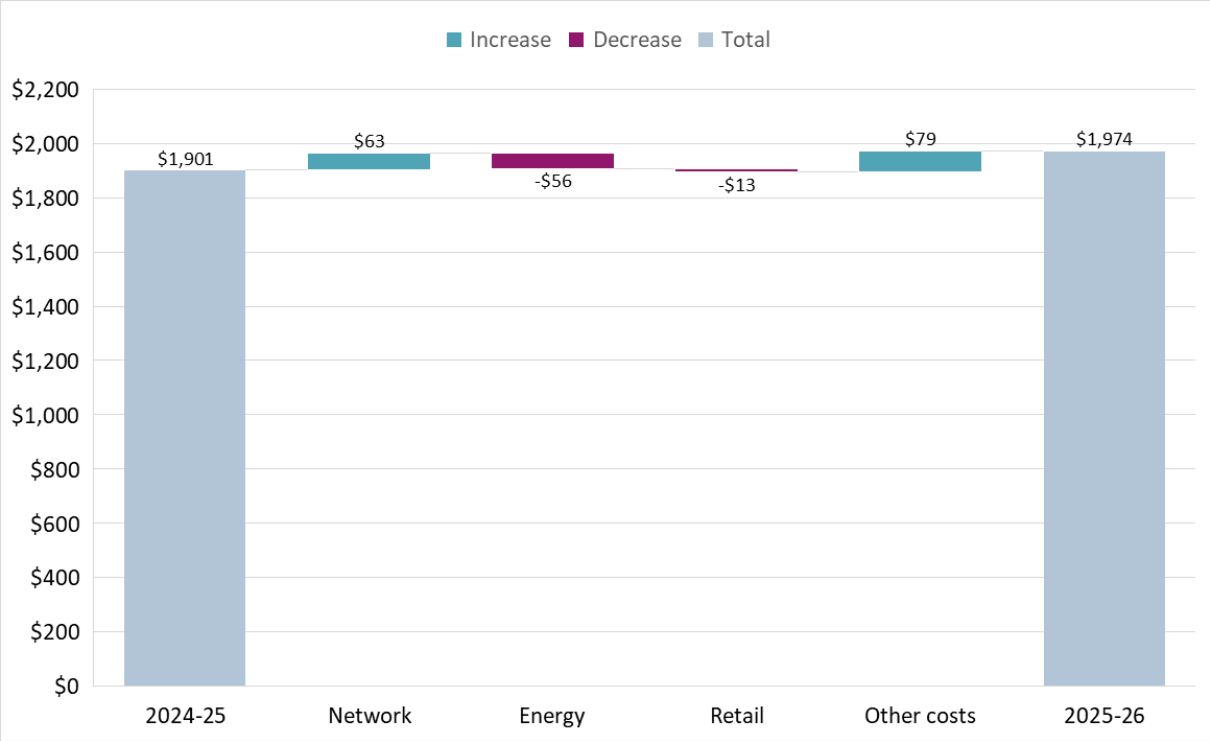
Key drivers

The increases to notified prices are driven by changes in the costs retailers incur, which can vary depending on the tariff type:

- tariffs 11 and 20 – the main residential and small business flat tariffs – have increased due to the increase in network costs, which outweigh the decrease in energy costs
- tariffs 31 and 33 – secondary load control tariffs – have decreased, reflecting a decrease in network costs.

Figure 2.3 shows the breakdown of individual cost components driving the overall bill increase for a typical customer on tariff 11. Note, the increase in other costs is due to the application of a standing offer adjustment (SOA) of 3.35% this year, compared to a SOA of -1.10% used last year, when the SOA was reduced following the DMO comparison (see section 5.1 for further details on the SOA).

Figure 2.3: Tariff 11 bill – changes in cost components, 2024-25 and 2025-26 (incl GST)



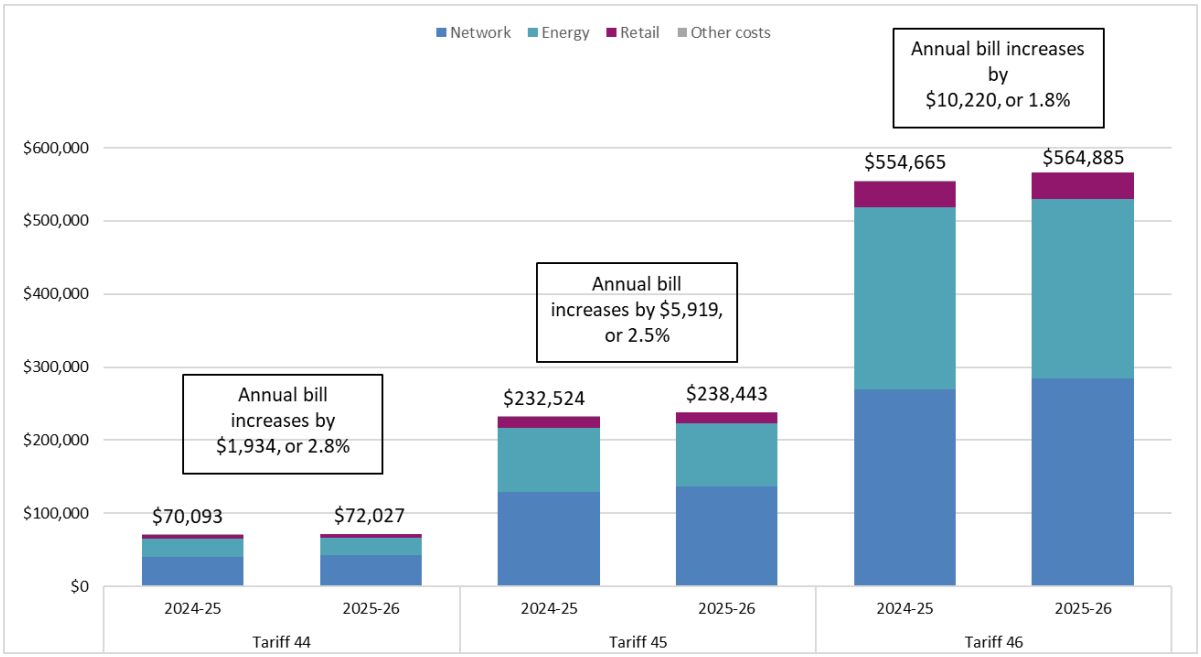
Small customer bill estimator

We have developed an online bill estimator tool for residential and small business customers. The tool provides an estimate of your next annual bill and how much this bill may differ from your previous annual bill. Customers are only required to enter their annual usage and any solar export amounts.

2.2 Large customers

Typical customers on tariffs 44, 45 or 46 are expected to pay around 1.8% to 2.8% more for electricity in 2025–26 (Figure 2.4). The increase is mainly driven by an increase in network costs, although this is partly offset by a decrease in energy costs.

Figure 2.4: Comparison of large business customer bills for 2024–25 and 2025–26 (incl GST)



Note: Other costs for large business customers are negative in 2025–26, so they do not appear in the figure above.

3 Overarching framework

Our approach to setting notified prices takes into account the cost level, structure and availability of tariffs, while having regard to the Queensland Government's UTP and the N+R cost build-up methodology.

The way we set notified prices is framed by the relevant factors outlined in the Electricity Act and the matters specified in the Minister's delegation (see Chapter 1). Specifically, the delegation requires us to consider:

- **the Queensland Government's UTP:** this policy ensures 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.[3] We also apply the default market offers (DMOs) set by the Australian Energy Regulator (AER) for south-east Queensland (SEQ) to cap notified prices for small customers, as detailed in section 5.1.
- **the N+R cost build-up methodology:** under this methodology we set notified prices by treating the N component (network costs) as a pass-through and determining the R component (energy and retail costs) ourselves.

Table 3.1 describes how we have regard to both the UTP and the N+R cost-build up methodology in setting notified prices. This approach aligns with the requirements of the delegation and reflects a long-standing practice in our price determinations.

Table 3.1: Overarching framework matters

Matter	Effect
Queensland Government's UTP	This means generally basing notified prices on: • for small customers – the cost of supplying small customers in SEQ • for large customers – the costs of supplying large customers in Ergon Distribution's east zone transmission region one, which is the region with the lowest supply cost connected to the National Electricity Market (NEM).
N+R cost build-up methodology	This means: • basing the retail tariffs on network prices and tariff structures approved by the AER (i.e. passing through the N component) • adding our estimate of energy and retail costs (i.e. the R component).

We understand stakeholder concerns around electricity prices and affordability in regional Queensland. Some stakeholders believe the current pricing framework is outdated and advocate for a fair and affordable tariff of no more than 16c/kWh[4] or a general freeze or reduction in prices for irrigators,[5] as well as us providing an explanation of how wholesale, network and retail costs are

[3] Minister's delegation, terms of reference, cl 2(a).
[4] BRIG, sub 1, p 1; QFF, sub 14, p 3.
[5] Giru, sub 11, p 3.

balanced.[6] However, the legislative framework mandates that we set prices based on the actual cost of electricity supply, rather than the price preferred by stakeholders. Our final determination details each of the cost components that make up the notified prices we set.

The Queensland Government's UTP is a policy that helps provide more affordable electricity prices in regional Queensland. By considering the UTP when setting prices, we can set lower prices than would otherwise be possible due to the higher cost of supply in regional Queensland.[7] The UTP works by having the Queensland Government subsidise the difference between the cost of supply and the prices customers pay through a community service obligation (CSO) payment, expected to be around $603 million in 2024–25.[8]

Some stakeholders raised broader concerns around the CSO payment, how prices are set, customer support, and available tariffs. In summary:

- QEUN supported continuing use of the UTP but wanted more transparency around how the CSO payment is calculated and reported.[9]
- Bundaberg Regional Irrigators Group (BRIG) said the CSO should go to Ergon Network instead of Ergon Retail to facilitate retail competition.[10]
- Caravan Parks Association of Queensland (CPAQ) recommended tailored support for regional caravan parks, such as grants or subsidies, to improve infrastructure and reduce energy costs. It also recommended retaining, redesigning or creating tariffs for seasonal, high-usage businesses, promoting flexible load control tariffs, and reforming demand charges to encourage renewable energy adoption.[11]
- Giru said we should work with the Queensland Government to offer rebates or concessions for agricultural users and improve their access to cost-effective tariffs.[12]
- QFF proposed a new 'solar soaking' tariff to support daytime pumping.[13]
- QEUN said a specific retail tariff for essential food businesses (like dairies, bakeries and aquacultural businesses) should be introduced to support these businesses and improve food security.[14]
- The Electric Vehicle Council (EVC) said the current pricing method is outdated and the Minister should allow more flexibility to create new tariffs, especially for electric vehicles (EVs), as reliance on network tariffs is not practical when regulatory resets occur once every 5 years.[15]

We acknowledge these are important issues, and some have been raised in previous reviews. However, these issues fall outside the scope of our price review, and it is not our role to modify and/or introduce support measures not already provided by the Queensland Government.

Our role is to set the notified prices using those methods and approaches we consider appropriate having regard to the legislative framework and matters specified by the Minister. While we acknowledge stakeholders' interest in introducing new alternative tariffs (including to assist the agricultural industry), in accordance with the N+R methodology we are required to consider, we base retail tariffs on the AER-approved network tariffs (i.e. structures, TOU windows and eligibility). That said, the Minister could direct us to create or modify retail tariffs to meet broader policy

[6] Giru, sub 11, p 3.
[7] Compared to SEQ, electricity needs to be transported over longer distances and to a lower density customer base.
[8] Queensland Government, *Budget Strategy and Outlook* , Budget Paper 2, Queensland Budget 2024–25, June 2024, p 219.
[9] QEUN, sub 13, pp 14–15.
[10] BRIG, sub 1, p 2.
[11] CPAQ, sub 2, pp 9–11.
[12] Giru, sub 11, p 3.
[13] QFF, sub 14, p 5.
[14] QEUN, sub 13, pp 27–28.
[15] EVC, sub 3, pp 2–3.

objectives or relevant energy-related initiatives. For instance, we continue to set the 'solar soaker' tariffs based on past ministerial advice.

We encourage stakeholders to raise these broader issues directly with the Minister. Customers facing hardship should contact their retailer to discuss available support options (see Box 2).

Box 2: Customer support in regional Queensland

Hardship policies

Under the National Energy Retail Law, retailers must help customers facing financial hardship or payment difficulties.

Ergon Energy Retail's Customer Assist program offers support, including payment plans, for eligible customers.

Government schemes, concessions and other programs and resources

- Eligible Queensland pensioners and seniors can access electricity rebates.
- The Home Energy Emergency Assistance Scheme provides one-off help for households struggling to pay their electricity bills due to an emergency or short-term financial crisis within the past 12 months.
- The ecoBiz program helps small to medium size businesses reduce energy costs with action plans, benchmarking and on-site coaching.
- The Drought Relief from Electricity Charges Scheme offers relief from electricity supply charges for drought-declared farming businesses using electricity to pump water for farming or irrigation purposes.

For more information on energy concessions and business support, visit the Queensland Government's website.

Other stakeholder resources

- QFF's website provides information on electricity prices, bills, government schemes and industry-specific resources.
- Ergon Energy Retail's website provides helpful information for households, businesses and farmers.
- The Australian Government's energy.gov.au website provides advice on managing bills and improving energy efficiency, and information on available rebates and assistance.

Dispute resolution

Customers can contact the Energy and Water Ombudsman Queensland to learn how to lodge a complaint or resolve a dispute with their electricity, gas or water supplier.

3.1 Changes to network tariffs

Under the N+R methodology, the network prices and tariff structures approved by the AER serve as the foundation for the retail tariffs we set. The AER has recently approved a new suite of network tariffs for the 2025–2030 regulatory period that impact the retail tariffs we set (see Box 3).

This year, the Minister has asked us to assess the network tariff changes and consider whether retail tariffs based on network tariffs that may become obsolete should be phased out gradually (with a transition period) or become obsolete within the tariff year.[16]

Box 3: Network tariffs for 2025–30

On 30 April 2025, the AER made its final determination on Energex and Ergon Distribution's network revenue and tariff proposals for 2025–30.[17] Key changes to tariffs include:

- adding TOU charges to various tariffs (including small customer demand tariffs) and changes to demand charges that affect tariffs 44 and 50A
- making changes to the TOU charging windows for small and large customer tariffs:
  - the off-peak window will be 11 am – 4 pm for residential customers and 11 am –1 pm for small and large business customers[18]
  - the peak window will be 5 – 8 pm on weekdays (for small and large business customers)[19]
- changing the usual minimum hours of supply for the underlying network tariff for tariff 33 to 16 hours (currently 18 hours)
- removing small customer tariffs 14B and 24B and the large customer tariffs 45, 46, 52A, 52B and 52C
- introducing new network tariffs from 1 July 2025, including high voltage CAC and dynamic flex storage tariffs.

Stakeholders had mixed views on the network tariff changes, including the transitional period that should be applied:

- EEQ supported implementing the changes, but said tariffs 12B, 12C and 14A (which are being updated to reflect the new network tariff as at 1 July 2025 without a transition period) should be re-established as new tariffs 12D, 12E and 14C (discussed further in Appendix A)[20]
- EEQ also generally supported a transitional approach for the tariff changes but, consistent with Ergon Energy Network and Energex, said tariffs 44 and 45 should be immediately

[16] Minister's delegation, schedule, cl 2(c).
[17] The regulatory proposals include tariff structure statements, which set out the network tariffs each distributor proposes to have in place over the regulatory period. More details on Energex and Ergon Distribution's proposals are available on the AER's website.
[18] The current off-peak window is 9 am – 4 pm for residential and small business customer tariffs. The current off-peak window for large customer tariffs varies.
[19] The current peak window is 4 pm – 9pm weekdays for small business customer tariffs (and varies for large business customer tariffs).
[20] EEQ, sub 4, p 3, sub 10, pp 3–4.

extinguished because demand data required for billing kW-based demand charges will not be available for basic meter customers after 1 July 2025 (discussed further in Appendix A).[21]

- BRIG supported changes to TOU windows for business customers to help their members manage energy use and costs better.[22]
- Some stakeholders raised concerns about whether customers will be better off (financially) and the potential confusion, costs and uncertainty these tariff changes may cause.[23] Cotton Australia and QFF said the TOU windows for small business tariffs should be consistent with the TOU windows for residential tariffs.[24]
- Several stakeholders said there should be a transition period for all affected retail tariffs,[25] or at least for retail tariffs that will be removed.[26] QFF said a transition period of at least 24-months should be provided (particularly for tariff 22C) to allow agricultural customers time to adjust and manage the financial impact of these changes.[27]

We acknowledge stakeholders' views, including the need to introduce new tariff structures in a timely manner. The network tariffs are approved by the AER, and we have based the notified prices on these.

We have noted requests for consistent TOU windows across business and residential tariffs, and for longer off-peak periods for the small business solar soaker tariff. However, the AER has approved the TOU windows developed by distributors based on demand analysis and broader stakeholder input.[28]

We considered the following factors when deciding whether a transition period is appropriate:

- the materiality of the change to the tariff
- availability of alternatives for affected customers
- the number of affected customers.

As a result, we decided:

- for most affected retail tariffs:
  - a 12-month transition period will apply (and the tariff will be made obsolete). Customers can use this time to understand the changes to their tariff options and consider adjustments to their usage.
  - the new tariff will be introduced based on the new network tariff structure (if the network tariff has not been withdrawn)
- for some retail tariffs:
  - no transition period will apply, and changes will take effect from 1 July 2025
  - for basic meter customers on tariffs 44, 45 and 46, no transition period will apply, due to practical (data) limitations. These customers must switch to an alternative tariff, such as tariff 43
  - tariffs 12B, 12C and 14A will be extinguished and replaced with new tariffs 12D, 12E and 14C to address, in part, retailer billing system issues.

[21] EEQ, sub 10, pp 3–5. Ergon Energy Network and Energex, sub 9, p. 2.
[22] BRIG, sub 1, pp 1–2.
[23] CPAQ, sub 2, p 7; QFF, sub 6, pp 4–5.
[24] Cotton Australia, sub 8, p 6; QFF, sub 14, pp 3–5.
[25] QFF, sub 6, pp 4–5; CPAQ, sub 2, p 8.
[26] BRIG, sub 1, p 2.
[27] QFF, sub 14, pp 4–6.
[28] AER, *Ergon Energy and Energex determinations 2025 to 2030 – Att 19*, draft decision, September 2024, pp 14–15, 34. We encourage stakeholders to review relevant materials on the AER's website, including the proposals and explanatory materials provided by Ergon Energy and Energex.

After considering stakeholder submissions, we consider a 12-month transition period strikes a fair balance – it gives customers time to understand and prepare for the new pricing arrangements, while minimising the period of misalignment between network and retail tariffs.[29]

Stakeholders, including QFF, asked for a 24-month transition period for tariff 22C, noting that many agricultural users have already adjusted their operations to suit the current TOU windows. We understand these concerns but have decided on a 12-month transition period. This provides time for customers to adjust without prolonging misalignment with the new network tariff arrangements.

We have also updated the CAC and ICC customer descriptions used in the retail tariff schedule to reflect changes made to these descriptions in the approved TSS.[30] We have provided a 12-month transition period for any customers currently on an ICC tariff that may be affected by the changes to the ICC customer description. We have also updated language in the retail tariff schedule around the availability of supply for load control tariffs to align with the approved underlying network tariffs.[31]

We encourage retailers to actively engage with affected customers and offer advice and tools to help them manage these tariff changes. EEQ is already developing communication plans and will update its online tariff comparison tool to help customers explore their options.[32] We encourage all customers to review their tariff options as they may be better off under the new tariff structures.

More details about our decision on network tariff changes are in Appendix A.

Table 3.2: Decision on retail tariffs impacted by network tariff changes

Retail tariff	Decision
Small customer tariffs	
12B	Extinguish the tariff immediately; no transition period. Introduce a new standard retail tariff based on the new tariff structure (new tariff 12D).
12C	Extinguish the tariff immediately; no transition period. Introduce a new standard retail tariff based on the new tariff structure (new tariff 12E).
14A	Extinguish the tariff immediately; no transition period. Introduce a new standard retail tariff based on the new tariff structure (new tariff 14C).
14B	Extinguish the tariff immediately; no transition period.
22B	Make the tariff obsolete and set a 12-month phase-out date. Introduce a new standard retail tariff based on the new tariff structure (new tariff 22D).
22C	Make the tariff obsolete and set a 12-month phase-out date. Introduce a new standard retail tariff based on the new tariff structure (new tariff 22E).
24A	Make the tariff obsolete and set a 12-month phase-out date. Introduce a new standard retail tariff based on the new tariff structure (new tariff 24C).
24B	Extinguish the tariff immediately; no transition period.

[29] Using a transition period will impact how network costs are calculated for these tariffs (see section 4.1 and Appendix B).
[30] Ergon Energy Network, *Tariff structure statement: in support of the Regulatory Determination Proposal 2025–30*, November 2024, as amended and approved by the AER April 2025, p 7.
[31] Energex, *Tariff structure statement: in support of the Regulatory Determination Proposal 2025–30*, November 2024, as amended and approved by the AER April 2025, pp 15, 19; Ergon Energy Network, *Tariff structure statement: in support of the Regulatory Determination Proposal 2025–30*, November 2024, as amended and approved by the AER April 2025, pp 16, 20.
[32] QFF, sub 6, pp 4–6 and sub 14, pp 5–6; CPAQ, sub 2, pp 7–10.

Retail tariff	Decision
31	Following the AER's final determination on the relevant TSS, no changes to this tariff are now required.
33	Implement the change to the tariff structure immediately; no transition period.
Large customer tariffs	
44	Make the tariff obsolete with a 12-month phase-out date and introduce a new standard retail tariff based on the new tariff structure (new tariff 44A). The tariff will only be eligible for customers with ADMs.[a]
45	Make the tariff obsolete with a 12-month phase-out date. The tariff will only be eligible for customers with ADMs.[a]
46	Make the tariff obsolete with a 12-month phase-out date. The tariff will only be eligible for customers with ADMs.[a]
50A	Make the tariff obsolete with a 12-month phase-out date and introduce a new standard retail tariff based on the new tariff structure (new tariff 50B).
52A	Make the tariff obsolete with a 12-month phase-out date.
52B	Make the tariff obsolete with a 12-month phase-out date.
52C	Make the tariff obsolete with a 12-month phase-out date.
60B	Following the AER's final determination on the relevant TSS, no changes to this tariff are now required.
Existing obsolete tariffs	
50	Set a 12-month phase-out date.
62A	Set a 12-month phase-out date.
65A	Set a 12-month phase-out date.
66A	Set a 12-month phase-out date.

a Further information about the restriction of these tariffs to customers with ADMs is provided in Appendix A.

New retail tariffs

We have introduced new retail tariffs based on the following new network tariffs approved by the AER, starting from 1 July 2025:

- tariff 49 – large TOU energy
- tariff 52G – CAC HV line TOU demand
- tariff 52F – CAC HV bus TOU demand
- tariff 52E – CAC 33kV TOU demand
- tariff 52D – CAC 66 kV TOU demand.[33]

Consistent with the N+R methodology, these new retail tariffs reflect the underlying AER-approved network tariffs. While Cotton Australia asked for tariff 49 to be available to all large customers,[34] this is not consistent with the network tariff arrangements.[35]

[33] See Appendix F for the relevant tariff structures.
[34] Cotton Australia, sub 8, pp 5–6.
[35] This tariff is only available to large business customers with monthly peak demand greater than 120 kVA and consumption less than 160 MWh per annum.

We have not introduced new retail tariffs for the new dynamic flex storage network tariffs as part of this review. Although the tariffs were approved at the network level and supported by EEQ, there was insufficient time and certainty around the tariff details prior to finalising this determination within the required timeframe.

We consider more time is needed to assess these tariffs and consider any potential retail implementation issues. However, the Minister may still decide to introduce them (or issue a delegation for us to do so) during 2025–26 ahead of the next prices review for 2026–27.

4 Individual cost components

The notified prices mainly consist of network costs (N component) – for electricity transport (via distribution and transmission networks) – and retail costs (R component) – for buying and selling electricity to customers – along with other costs.[36]

We use the N+R cost build-up methodology to set notified prices by:

- setting the N component – based on network prices approved by the AER
- determining the R component – to reflect the costs an efficient retailer incurs in buying and selling electricity, including wholesale energy costs (WEC), other NEM-related costs, and the costs of operating a retail business.

4.1 Network component

The N component includes costs for electricity transport through transmission and distribution networks, as well as jurisdictional scheme charges.[37] The costs are regulated by the AER and reflected in the network prices it approves.

We set the N component in a manner that reflects the overarching framework matters – that is, the UTP and N+R methodology (see chapter 3). This is consistent with the requirements of the delegation and the broader pricing approach applied in previous determinations.

This year, there are two new matters impacting the N component:

- The cost of legacy (accumulation) meters is now included in network prices approved by the AER.[38] As a result, legacy metering costs are captured in the N component of network prices.[39]
- We are maintaining some retail tariffs that no longer have an underlying network tariff (see section 3.1). As a result, we used a price indexation approach to set the N component for these retail tariffs (discussed below).[40]

The price indexation approach uses the approved 2024–25 network prices and adjusts these by the AER's nominal x-factor (to account for expected changes in network costs determined by the AER, applied to all existing retail tariffs without an underlying network tariff). We then include relevant jurisdictional scheme charges and legacy metering costs, consistent with the way these costs are now captured by the AER. Importantly, the use of the price indexation approach will be limited to the 2025–26 period, as the relevant retail tariffs are set to be discontinued after a 12-month period (see chapter 3).

Further detail on the indexation method and how it is applied is in Appendix B.

[36] Other costs and related adjustments are discussed in chapter 5.
[37] In Queensland, these charges include the Solar Bonus Scheme and Australian Energy Market Commission levy costs.
[38] See AER, *Energex Determination 2025 to 2030*, final decision, April 2025, p 31.
[39] These costs were previously captured in the R component of small customer notified prices (see section 4.2).
[40] The price indexation approach is applied to determine the N component for tariffs 44 and 45. While the AER approved network prices underlying tariff 44 and 45, these were only transitional prices, applying to basic meter customers until their next meter read (see AER, *Ergon Energy and Energex Determination 2025 to 2030 (Att 19 TSS)*, final decision, April 2025, p 22).

Stakeholders did not comment specifically on these matters but did raise some broader concerns, which are discussed in section 5.5.

For this determination, we used the network prices approved by the AER for Ergon Energy Network and Energex.[41] Table 4.1 sets out the basis on which we determine the N component.

Table 4.1: Basis for determining the N component

Tariff	Basis
Small customers	
Flat and secondary load control tariffs	Relevant Energex network prices (the charges and tariff structures levied by Energex in SEQ)
Limited access obsolete tariffs (tariffs 62A, 65A and 66A)	Relevant network prices for Ergon Energy Network's east zone, transmission region one[a]
All other existing retail tariffs	Relevant Energex network prices but utilising Ergon Energy Network's tariff structures
Large customers	Relevant network prices for Ergon Energy Network's east zone, transmission region one (the Ergon Energy region with the lowest cost of supply that is connected to the NEM).
All tariffs made obsolete, with a 12-month transition period	Relevant 2024–25 network prices, adjusted by the AER's nominal x-factor and including legacy metering and relevant jurisdictional scheme charges.

a These tariffs are only available in the Ergon Energy area.

Network costs included in notified prices

Network costs have increased for most small and large customers compared to last year. In part, this is due to the inclusion of legacy metering costs in the N component in 2025–26.[42] The change to the annual bill for a typical customer is set out in Figures 4.1 and 4.2.[43]

[41] AER, *Ergon Energy – 2025–26 pricing proposal*, AER website, 26 May 2025; AER, *Energex – 2025–26 pricing proposal*, AER website, accessed 26 May 2025.
[42] These costs were previously included in the R component, as discussed in section 4.2.
[43] Amounts presented are rounded. Percentage changes are based on unrounded amounts.

Figure 4.1: Network costs – small customer tariffs (incl GST)

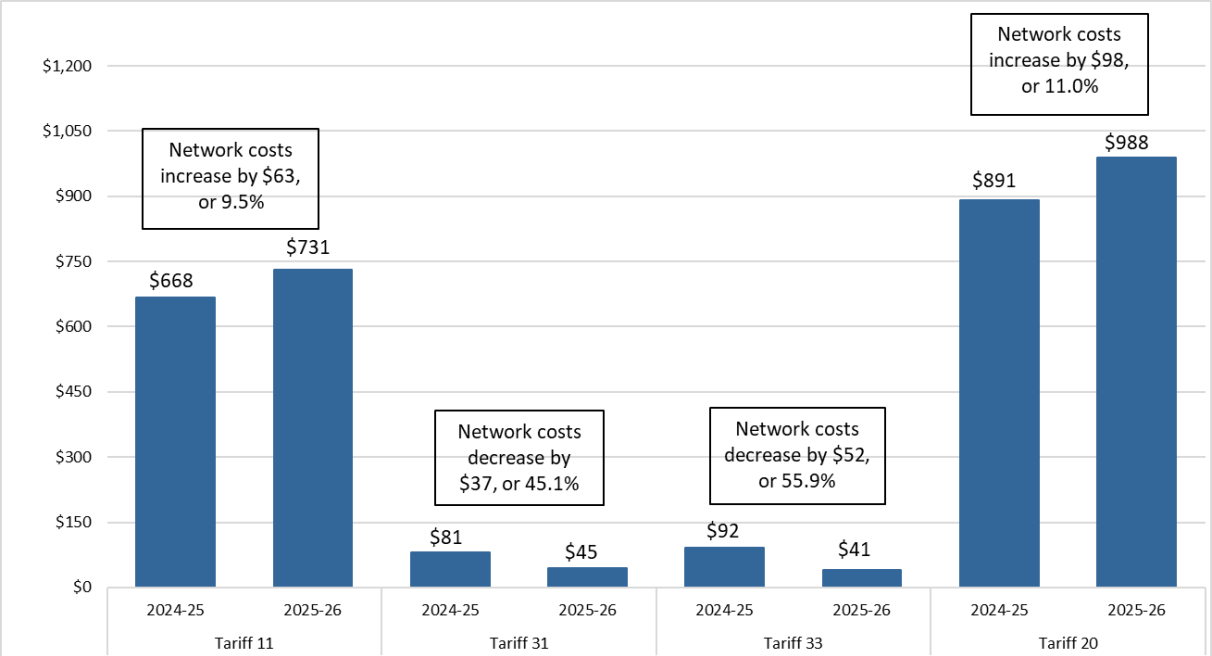
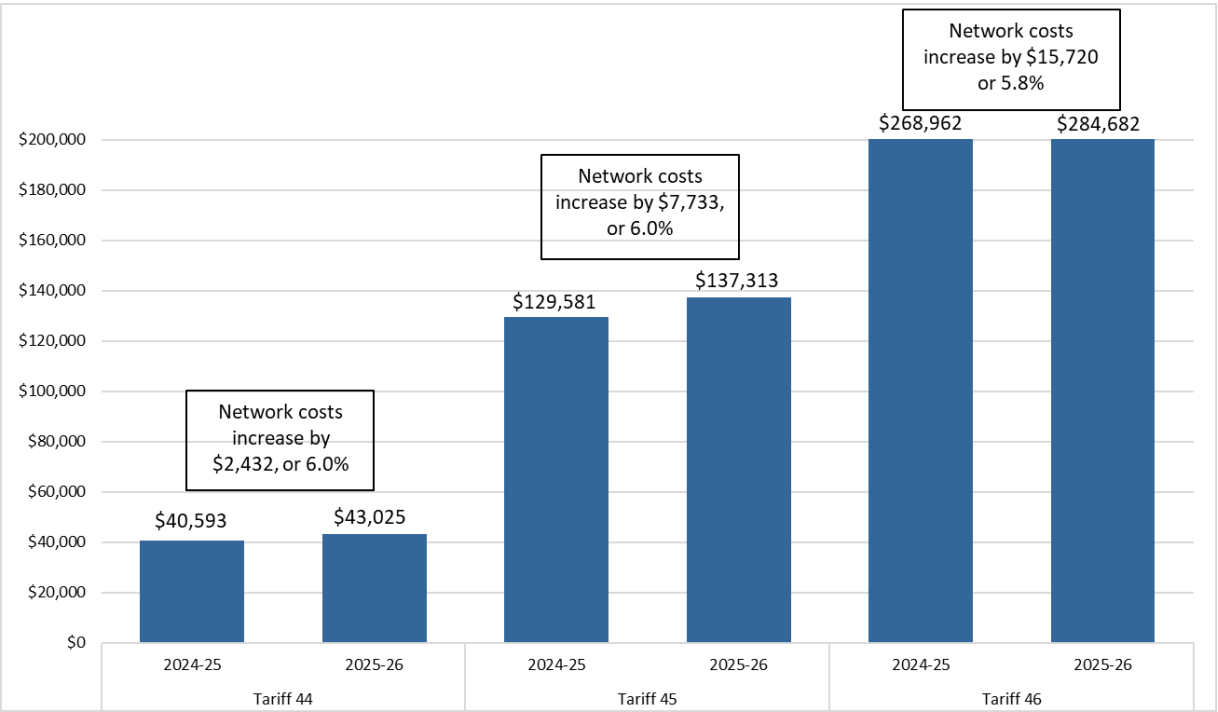


Figure 4.2: Network costs – large customer tariffs (incl GST)



4.2 Retail

The R component includes energy costs and retail costs. It covers the costs retailers incur to buy electricity from the NEM, run their operations and provide metering services.

4.2.1 Energy costs

Energy costs include wholesale energy costs (WEC), which are the costs of purchasing electricity from the NEM, and other costs such as those related to Renewable Energy Target obligations and energy losses.

This year, we engaged ACIL Allen (ACIL) to provide expert advice and energy cost estimates. Relevant information from ACIL's report[44] is available on our website.

Wholesale energy costs

The WEC relates to the costs retailers incur when purchasing electricity from the NEM to meet customer demand. To manage the impact of fluctuating electricity prices (spot prices), retailers typically use strategies like financial hedging, contracts and operational methods.[45]

Our WEC estimates are based on ACIL's advice using:

- **a market hedging approach** – which estimates the wholesale energy costs for a retailer hedging spot price risk using ASX Energy contracts
- **the latest available data** – including contract data up to 9 May 2025.

This approach is consistent with the method used in previous years (see Box 4).

[44] ACIL Allen, *Estimated Energy Costs*, final report, prepared for the QCA, May 2025.
[45] Spot prices are settled every 5 minutes and currently range from -$1000 to $18,600 per MWh. (The market price cap will increase to $20,300 per MWh for the period from 1 July 2025 to 30 June 2026. See AEMC, *AEMC updates market price cap for 2025-26*, media release, 27 February 2025, AEMC website, accessed 1 May 2025.)

Box 4: Estimating wholesale energy costs

The estimated WEC[46] for a given year is based on:

- **wholesale energy spot prices** – which are simulated by considering:
  - supply factors in the NEM, such as power plant availability and renewable energy production
  - demand changes, based on weather data, historical demand, solar uptake and demand forecasts from the Australian Energy Market Operator (AEMO)
  - the way generators bid in the market, including potential changes in their bidding behaviour, based on market conditions and costs
- **retailers' hedging strategies and contract prices** – which are estimated using a model to simulate the WEC for a retailer managing spot price risk through (publicly available) ASX Energy contracts:
  - contract prices are estimated using the trade-weighted average of ASX Energy contract prices for quarterly base and cap contracts,[47] based on trade data for Queensland up to 9 May 2025
  - ASX contract trading usually begins several years before the relevant financial year, like in mid- to late 2022 for 2025–26 contracts, reflecting how retailers lock in their costs progressively over time.

This WEC simulation method produces 594 annual hedged energy cost estimates. We use the 95th percentile of these estimates as our WEC, which reduces the risk of understating the costs a prudent retailer would face in the NEM.[48]

This year, we made a minor refinement to how we consider historical demand profiles (discussed below). We consider our approach provides transparent and robust WEC estimates.[49] The approach uses a significant number of simulations and the latest available information to reflect current market conditions. For example, where current market conditions point to a softening in energy markets, this will be reflected in our WEC estimates and passed through to consumers, as suggested by Giru.[50]

EEQ noted that retailers are increasingly using 'shaped' contracts to manage changing demand patterns resulting from the growth in solar generation. EEQ suggested that using a shaped contract

[46] This summarises key aspects of ACIL's method used to estimate the WEC. See ACIL's report, pp 7–21.
[47] Consistent with past reviews, calculations of the trade-weighted contract price consider additional call options data for base contracts. See ACIL's report, p 39.
[48] Another reason for adopting the 95th percentile is that in the NEM, prices can increase significantly more than they can decrease.
[49] ASX Energy contract information is readily available online. Additionally, ACIL compared the WEC estimates produced in previous reviews against actual movements in the trade-weighted contract price and found they were generally closely aligned (ACIL's report, p 50). The nature of the task (i.e. setting annual forward-looking prices) means there may be some differences between the estimated WEC for a given year and the actual WEC incurred by a prudent retailer. However, over the long run, we expect any under- or over-estimation to balance out. See ACIL's report, pp 22–25.
[50] Giru, sub 11, p 2.

price could result in a more market-reflective WEC estimate.[51] While we acknowledge that shaped contracts are used, data on their use and market valuation is not transparent, as these contracts are not traded on ASX Energy. We will continue to monitor their use and the availability of relevant data.[52]

EEQ also raised concerns about the hedge product mix used in our WEC modelling, particularly the volume of cap contracts.[53] It noted that the traded volume of ASX caps includes many speculative trades and may not accurately reflect hedging availability. EEQ suggested open interest in cap products may be a better indicator.[54]

We do not expect Ergon Retail to replicate the hedge product mix used in our modelling. Our hedging approach is intended to proxy the range of instruments available, not prescribe a specific strategy. Retailers may use a mix of ASX-listed and non-ASX-listed instruments in practice.[55] Therefore, we do not consider differences in cap volumes between our model and actual retailer strategies to be problematic.[56]

Historical demand profiles

We continue to use a combination of the net system load profile (NSLP)[57] with advanced digital meter (ADM) data when considering historical demand profiles. Consistent with our 2024–25 review, the ADM data *includes* demand satisfied by solar PV exports, as this better reflects the total demand a retailer faces when supplying its customers.[58]

EEQ noted that, in practice, retailers typically build their hedge books using a demand profile that *excludes* demand satisfied by solar exports (i.e. resulting in a peakier demand profile[59]). EEQ said that our modelling of the WEC should account for this, as the current hedge product mix used may not reflect that of a prudent retailer.[60]

While we acknowledge a retailer may hedge based on a peakier profile, we consider it appropriate to include demand satisfied by solar exports in our analysis (and demand profile). This is because regardless of whether the energy comes from the NEM or is sourced from solar PV customers, the notified price applies to all consumption. Therefore, we estimate the cost of supplying energy based on total demand. We would expect a prudent retailer to reflect any difference in hedging costs due to solar PV exports in the feed-in tariff (FiT). We have taken this into account when setting the solar FiT for regional Queensland.

For WEC estimates, we normally use two to three years of historical demand data. However, this year we used a shorter period – from 1 October 2023 to 30 September 2024 – to avoid including an artificial increase in demand caused by a manual adjustment made by AEMO in earlier years.[61] Since the adjustment will not affect retailers in 2025–26, we consider it appropriate to exclude it. We have

[51] EEQ said this data would be reported to the AER from April 2025. As shaped contracts usually apply to morning and evening peaks, it recommended scaling up the base contract price using the ratio of evening peak to flat spot prices. See EEQ, sub 4, p 1.
[52] See ACIL's draft report, pp 33–34.
[53] EEQ said the volume of caps exceeds what is available in the market, which would increase the price above modelled levels. It also considered that the risk-adjusted return on the portfolio would exceed risk appetite thresholds. See EEQ, sub 10, p 2.
[54] EEQ, sub 4, p 2.
[55] Examples of strategies include over-the-counter (OTC) contracts, power purchase agreements (PPAs) and investing in generating units.
[56] See ACIL's draft report, p 34.
[57] AEMO publishes the NSLPs used to approximate the demand of customers on accumulation meters.
[58] See ACIL's report, pp 11–12.
[59] Excluding demand from solar PV exports significantly reduces demand during the middle of the day.
[60] EEQ, sub 10, p 2.
[61] The artificial increase impacts demand from 1 October 2021 to 30 September 2023 and arises due to a manual adjustment by AEMO to address issues from the introduction of 5-minute settlements. See ACIL's report, p 15.

confirmed that using this shorter data period still provides enough data (and data variation) to produce robust estimates.

Outcomes and key drivers

Compared to last year, WEC estimates for 2025–26 have:

- decreased by around 4.6% for small customer primary tariffs
- increased by around 8.0% for small customer load control tariffs (tariffs 31 and 33)
- increased by around 0.5% for large customer tariffs.

Key drivers of these changes:

- **Small customer primary tariffs (tariffs 11 and 20):**

  The demand profiles have flattened, reducing hedging costs (all other things equal), including by reducing the degree of over-hedging. [62,63] Our modelling for these profiles also assumes a greater reliance on cap contracts, which have seen only marginal price increases – unlike base contracts, which are more heavily used for hedging other customer load profiles.

- **Small customer load control tariffs (tariffs 31 and 33):**

  The increase is driven by an increase in the trade-weighted price of base contracts and higher gas prices, which are particularly relevant due to the shape of the demand profiles associated with these tariffs.[64]

- **Large customer primary tariffs (tariffs 44, 45 and 46):**

  A modest increase in the trade-weighted price of base contracts has offset the impact of a slightly flatter demand profile, resulting in a small overall increase.

Time-varying wholesale energy costs

For time-of-use tariffs 12E[65], 22C and 22E[66], we apply time-varying WEC estimates to create stronger price differences between peak and non-peak periods, compared to their base tariffs (12D[67], 22B and 22D[68]).

We set these time-varying WECs based on ACIL's advice, using the same method applied in previous years.[69] This involves:

- using the WEC estimates for small customer tariffs 12D, 22B and 22D as the base
- developing weightings for different times of the day, based on demand-weighted spot price variations, where daytime (non-peak) generally has lower prices and evening (peak) has higher prices. The time periods are based on AER-approved network tariff structures[70]
- applying these weightings to the WEC estimates (described above) to set lower rates for non-peak periods and higher rates for peak periods.

[62] The flatter profiles reflect the continued roll-out of ADMs, allowing us to account for demand satisfied by solar exports. Because of data constraints, the NSLP excludes demand satisfied by solar exports – resulting in lower demand during daytime periods and a peakier demand profile. For the ADM profile, we can include demand satisfied by solar exports.
[63] In other words, reducing the extent to which contract levels exceed actual demand.
[64] The load control demand profiles are peaky during the late evening period, when gas prices influence spot price outcomes – and gas prices have been higher.
[65] This was referred to as 12C in the draft determination (Chapter 3 and Appendix A explain why the name has changed).
[66] This tariff replaces 22C, which will be made obsolete, with a 12-month transition (see Chapter 3 and Appendix A).
[67] This was referred to as 12B in our draft determination (Chapter 3 and Appendix A explain why the name has changed).
[68] This tariff replaces 22B, which will be made obsolete, with a 12-month transition (See Chapter 3 and Appendix A).
[69] This approach was developed in our 2023–24 final determination, sections 3.2.1 and 4.2.1.
[70] See section 3.1 for more detail on the changes to the network tariffs (and time periods) approved by the AER.

This method maintains the same total WEC as for tariffs 12D, 22B and 22D but changes how costs are spread throughout the day, to strengthen price signals. Table 4.2 sets out the time-varying WEC estimates included in notified prices this year.

Table 4.2: Time-varying WECs for tariffs 12E, 22C and 22E

Period	Tariff 12E[a] c/kWh	Tariff 22C[b] c/kWh	Tariff 22E[c] c/kWh
Peak (evening)	24.55	25.34	23.58
Off-peak (day)	3.99	4.17	3.60
Shoulder (night)	14.26	15.40	14.14

a For tariff 12E, peak usage is 4 pm to 9 pm all days; off-peak (day) usage is 11 am to 4 pm all days; shoulder (night) usage is all other times.
b For tariff 22C, peak usage is 4 pm to 9 pm weekdays; off-peak (day) usage is 9 am to 4 pm all days; shoulder (night) usage is all other times.
c For tariff 22E, peak usage is 5 pm to 8 pm weekdays; off-peak (day) usage is 11 am to 1 pm all days; shoulder (night) usage is all other times.

Other energy costs

Retailers incur other energy costs when buying electricity from the NEM. We estimate these costs based on ACIL's advice, which uses reliable data sources and ensures these costs appropriately reflect what retailers are likely to pay.[71]

Table 4.3 provides more details on these costs and how we estimate them.

Table 4.3: Other energy costs – description and estimation approach

Cost item	Description	Approach
Renewable energy target (RET) costs	Costs related to buying certificates to meet the mandated RET targets, which include the Large-scale Renewable Energy Target (LRET) and the Small-scale Renewable Energy Scheme (SRES).[72]	LRET costs – estimated using forward prices for large-scale generation certificates (LGCs) and renewable power percentage (RPP) values, based on the mandated LRET targets and estimates of electricity acquisitions.
		SRES costs – estimated based on the clearing house price for small-scale technology certificates (STC) and the small-scale technology percentage (STP).
NEM fees	The costs to AEMO for operating the NEM.	Estimated based on the 2025–26 AEMO draft budget report (published April 2025), which includes both a fixed and variable component.[73]
Ancillary services	The costs of services used by AEMO to maintain power system safety, security and reliability.	Estimated using the average historical costs from the past 52 weeks, published by AEMO.

[71] See ACIL's report, pp 25–31, 51–60.
[72] LRET and SRES are meant to encourage the electricity sector to increase generation from renewable energy and reduce greenhouse gas emissions. Retailers pay for these incentives by buying LGCs and STCs. LGCs or STCs are created when eligible electricity is generated by large or small renewable energy systems.
[73] See ACIL's report, p 25. The fixed NEM fee is recovered in the daily supply charge as a fixed energy cost component. This differs from 2024–25, where fixed NEM fees were captured in the (fixed) retail cost component for presentational purposes.

Cost item	Description	Approach
Prudential costs	The costs of providing financial guarantees to AEMO and to lodge initial margins with the ASX for futures contracts.	Estimated using AEMO's prudential requirements and margin requirements for trading in the ASX futures market.
Energy losses	The costs related to energy lost when electricity is transported across the network;[74] therefore, retailers need to buy more electricity than customers use because of these losses.[75]	Estimated by applying transmission and distribution loss factors published by AEMO in April 2025.

Regarding LRET costs, EEQ said the current method for determining the LGC price did not reflect actual practices, as it assumes all certificates are bought in the forward market, when some are also purchased in the spot market. Accordingly, EEQ said that ACIL's approach does not capture the full suite of LGC pricing that retailers use to satisfy their compliance obligations. For example, it excludes LGCs tied to power purchase agreements that retailers have in their portfolio.[76] EEQ also said we should capture more market data instead of relying on one broker's input.[77]

We acknowledge that retailers use different strategies to buy certificates, but our method aims to estimate a proxy for the range of strategies that could be adopted, and it may not reflect some features of a retailer's actual practices. Since daily trade prices from different trade brokers are strongly aligned, we do not consider there is a need to add input from more brokers.[78]

BRIG said that Reliability and Emergency Reserve Trader (RERT) costs[79] should be separated in the cost stack and funded by Treasury.[80] As required by the Electricity Act, we must have regard to the costs of supplying electricity, which include RERT costs.[81] However, since RERT was not triggered in the 12 months before the final determination, we have not included any RERT costs.[82]

Other energy costs[83] have decreased compared to last year by:

- 12.1% ($2.19/MWh) for small customer tariffs
- 15.9% ($2.78/MWh) for large customer tariffs.

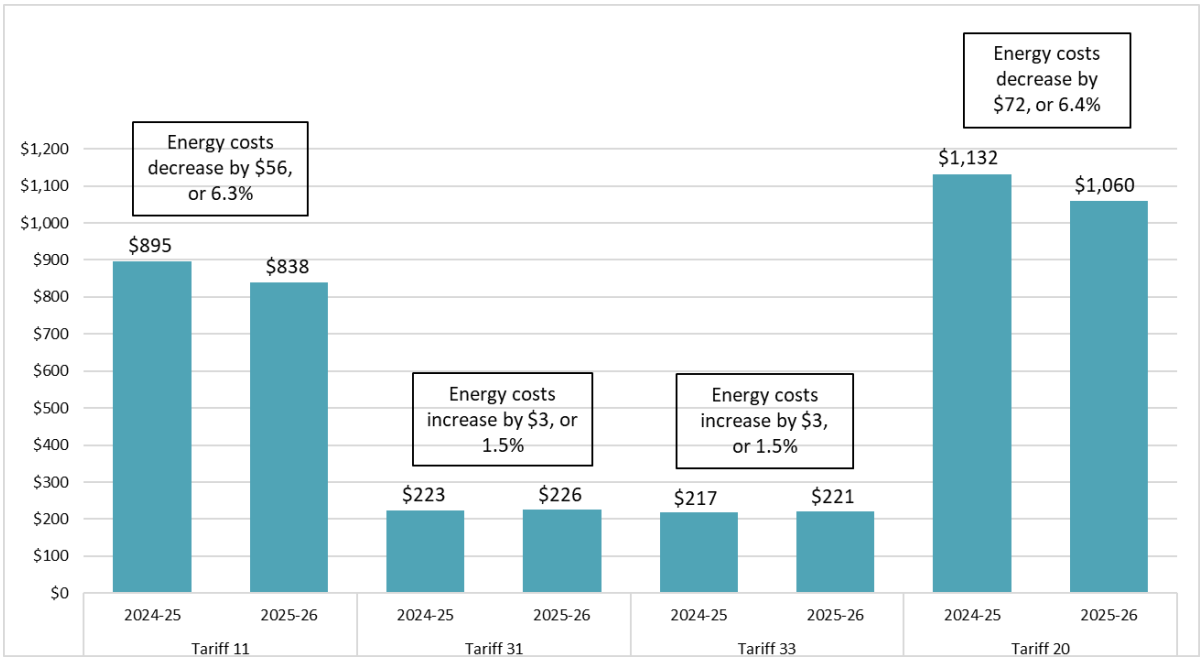
The reasons for these changes are explained in ACIL's report.[84]

[74] The losses occur primarily due to resistance along power lines, which causes heat and reduces the amount of electricity that reaches the end user.
[75] Energy losses are applied to the combined WEC and all other energy costs to determine the associated cost.
[76] EEQ, sub 4, pp 2–3 and sub 10, p 3.
[77] EEQ, sub 4, pp 2–3.
[78] See ACIL's report, p 34.
[79] RERT costs are levied by AEMO to maintain 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.
[80] BRIG, sub 1, p 2.
[81] Electricity Act, s. 90(5)(a)(i).
[82] RERT costs are estimated using historical costs published by AEMO and do not include the June 2022 event costs. See ACIL's report, pp 27–29.
[83] This excludes costs associated with energy losses and fixed NEM fees.
[84] The changes to each cost category are set out in ACIL's report, p 59.

Total energy costs included in notified prices

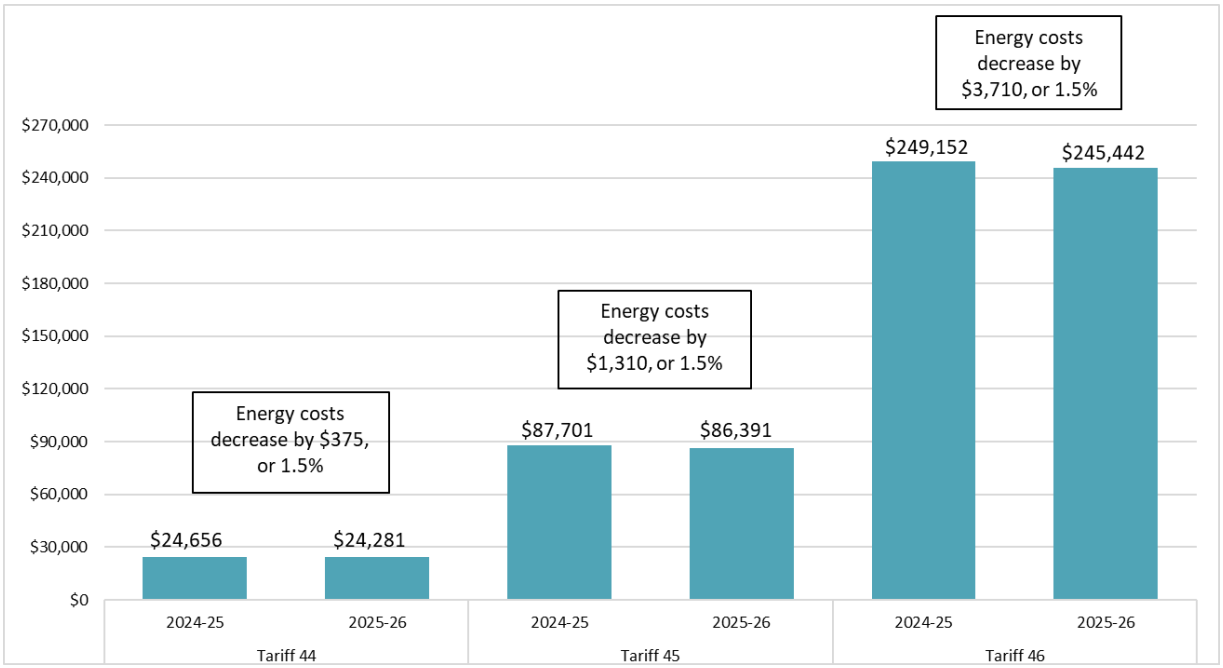
Overall, energy costs are estimated to decrease for most small and large customers. Figures 4.3 and 4.4 show the total energy costs in notified prices compared to last year's estimates, by tariff type for typical small and large customers.

Figure 4.4 Energy costs – small customer tariffs (incl GST)



Note: In 2025–26, NEM fixed fees are included in energy costs. To enable a like-for-like comparison, we have also included these fees in the 2024–25 energy costs (last year these costs were included in retail costs for presentational purposes).

Figure 4.4: Energy costs – large customer tariffs (incl GST)



Note: In 2025–26, NEM fixed fees are included in energy costs. To enable a like-for-like comparison, we have also included these fees in the 2024–25 energy costs (last year these costs were included in retail costs for presentational purposes).

4.2.2 Retail costs

Retail costs relate to the costs of running a retail business. They 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.

We determine retail cost allowances using a well-established benchmark that estimates the costs an efficient retailer would incur, based on market data.[85] Table 4.4 sets out the basis for determining retail cost allowances this year.

Table 4.4: Basis for determining retail cost allowances

Customer type	Basis
Small customers	Apply established benchmark costs (based on the costs of supply in SEQ) by: • adjusting last year's fixed retail costs[a] for inflation[b] (to maintain fixed costs in real terms) • maintaining the variable retail cost allocators at: – 7.25% for residential customers – 18.70% for small business customers.
Large customers	Apply established benchmark costs (based on the costs of supplying large customers) by: • adjusting last year's fixed retail costs[a] for inflation[b] to maintain fixed costs in real terms • maintaining the variable retail cost allocators at 6.0445%.

a Fixed retail costs were set in our 2021–22 notified price review and have been adjusted for inflation each year since.
b We use the RBA's CPI forecast of 3.1% for the financial year ending June 2026. See RBA, *Statement on Monetary Policy*, May 2025, p 66.

Retail costs for the new retail tariffs were set in a consistent manner, applying the established fixed and variable retail cost allocators. For new large customer tariffs, we used existing estimates for fixed retail costs relevant to the specific tariff class,[86] consistent with our approach in previous reviews.

EEQ said we should consider cost pressures when setting the retail cost allowances, particularly given some costs have increased beyond inflation in recent years. For instance, administrative costs (such as Australia Post's costs) have increased by more than inflation. This price rise is further exacerbated by the conversion of quarterly to monthly billing for ADM customers and this cost impost will grow as the accelerated roll-out of ADMs continues. EEQ said we should consider a

[85] The benchmark retail cost allowances were first established in 2016–17. We then reviewed the benchmarks in our 2021–22 notified price review and revised the small customer allowances using updated market information (allowances for large customers were reviewed and ultimately maintained).
[86] For tariff 44A, we use the fixed retail costs estimated for the existing large business demand tariff (tariff 44); for tariffs 49 and 50B, we use the fixed retail costs estimated for existing time-of-use tariffs (tariffs 50 and 50A); for tariffs 52D–52G, we use the fixed retail costs estimated for the existing connection asset customer (CAC) tariffs (tariffs 51A–D and 52A–C).

mechanism to encourage customers to use electronic communication, and it could work with us to develop and implement one that is appropriate.[87]

QEUN said we should update the retail cost estimates and remove the customer acquisition costs incurred by retailers operating in SEQ (given the lack of competition in regional Queensland), which ACCC said was around $48 per customer in 2018.[88]

We acknowledge that the costs of running a retail business evolve over time. Given retail costs were comprehensively reviewed in 2021–22, it may be beneficial to conduct another assessment in a future review. This would allow us to re-evaluate the actual costs of supplying small customers in SEQ, taking into account any potential costs arising from the roll-out in ADMs, as well as potential savings in retail costs that may have occurred due to productivity improvements.

We considered QEUN's comments but did not make changes to the retail cost allowances.[89] Consistent with the UTP, these benchmarks are designed so that retail costs incorporated into notified prices are reflective of retail costs in SEQ. As a result, the retail costs we set are generally lower than what they otherwise would be.

While we appreciate EEQ's suggestion, we consider EEQ is best positioned to explore and implement initiatives that encourage customers to adopt electronic communication, especially given the potential cost savings that could be realised.

ADM service costs – small customers

Retail metering service costs cover:

- the capital and operating expenses associated with customer meters, specifically the ongoing roll-out of ADMs across regional Queensland
- a true-up mechanism to reconcile any under- or over-recovery of metering costs in the previous year.

This year we have not included costs associated with legacy (accumulation) meters as these costs are now (from 2025–26 onwards) included in network prices.[90]

ADM costs

We have set retail metering service costs for ADMs using a similar approach to last year's notified price review. We used the average cost incurred per ADM in SEQ (as approved by the AER) and applied it to the forecast deployment of smart meters in the Ergon Distribution region. This ensures customers in regional Queensland pay no more than customers in SEQ, consistent with the UTP.

EEQ broadly agreed with our approach but is concerned the AER's method understates the metering costs per customer and will cause an under-recovery of smart meter costs in regional Queensland.[91]

While we note EEQ's concerns, it is important to highlight that the metering costs have been approved by the AER following consultation and will apply in SEQ from 1 July 2025. As such, we consider it appropriate to ensure customers in regional Queensland pay no more than their counterparts in SEQ for metering, in line with the UTP.

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[87] EEQ, sub no. 4, p 4.
[88] QEUN, sub 13, p 21.
[89] QEUN's other comments, such as requesting we be provided with actual retail cost data from Ergon Retail (QEUN sub 13, p 21), is not relevant (given we use SEQ retail cost benchmarks) and not within the scope of our review.
[90] See AER, *Energex Electricity Distribution Determination 2025 to 2030: Overview*, final decision, April 2025, p 31.
[91] EEQ, sub 10, p. 5.

Including a true-up mechanism

This year, we included a true-up mechanism for metering costs to reconcile any over- or under-recovery of metering costs from the previous year.

This process involves:

1. comparing actual versus forecast ADM deployment – this involves comparing the 2024–25 retail metering service costs, which are based on actual ADM deployment, to the metering cost allowance currently included in notified prices, which is based on forecast ADM deployment[92]
2. determining the pass-through amount – any under- or over-recovery of metering costs identified in step 1 is adjusted for timing differences to determine the pass-through amount to be included in 2025–26 notified prices.

Based on our assessment, we estimated an under-recovery of retail metering service costs in 2024–25 due to a higher than forecast deployment rate of ADMs (of 56.6%, compared to 55.2%).[93] After adjusting for timing differences, this results in an under-recovery of 0.411 c/day. This amount is added to the metering costs included in 2025–26 notified prices.

Retail metering service costs are included in the daily supply charge for small customer primary tariffs. Table 4.5 sets out the basis on which we determined the small customer metering costs.

Table 4.5: ADM costs for small customer tariffs, 2025–26 (excl GST)

Description	Metering costs (c/day)	Approach
Primary tariff	23.660	To calculate the base metering cost, we used: • relevant ADM metering costs that apply in SEQ, determined by the AER[a] • the forecast deployment rate of ADMs for small customers in regional Queensland for 2025–26, as provided by Ergon Retail.
True-up adjustment	0.411	To estimate the under- or over- recovery of metering costs we: • calculated the difference between the retail metering service costs based on a forecast ADM deployment (55.2%) and those based on actual ADM deployment (56.6%) • adjusted the difference (under-recovery) in costs for timing differences (by applying the 9.15% weighted average cost of capital).
Overall charge	24.071	The overall charge is the retail metering service costs plus the true-up adjustment.

a These are the same costs the AER uses to set the ADM costs included in the DMO charges for the Energex distribution area. See AER, *Default market offer prices*, final determination, May 2025.

[92] As the costs are based on mid-year deployment forecasts, we used the actual deployment rate (at December 2024) to calculate the actual metering costs used in this comparison. A higher actual mid-year deployment rate means more metering costs should have been included in the current metering costs included in 2024–25 notified prices.

[93] Deployment rates were used in conjunction with the SEQ average cost incurred per smart meter to determine ADM costs for regional customers.

Retail charge for manually reading a type 4A meter

There are costs involved with manual meter reads that are required if a customer has chosen to disable the remote communication function of the ADM.

We have been asked to consider setting a series of retail charges based on Ergon Retail's average costs for manually reading type 4A meters, differentiated by customer feeder types (e.g. urban, rural or isolated) to better reflect the charges that may be incurred for different customer types.

Given the information available, we have set this charge in the same manner as last year – based on the special meter read fee in Ergon Energy Network's 2025–26 network price list of $49.86.[94]

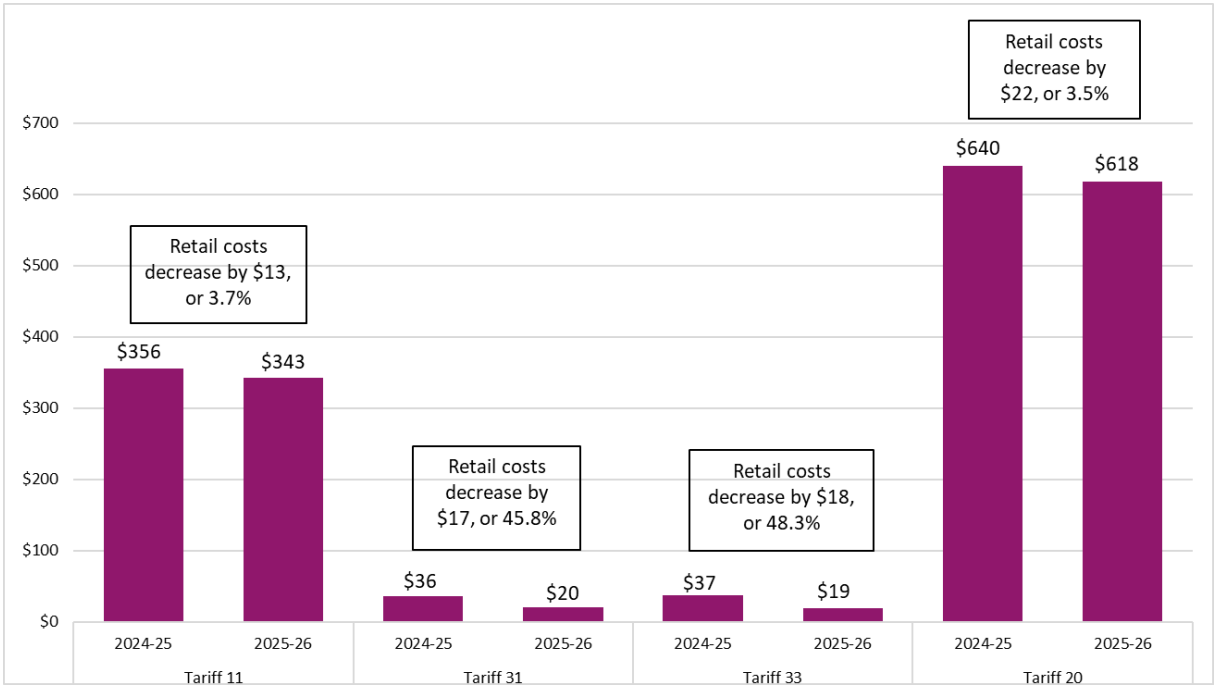
This continues to be a reasonable benchmark for setting this fee, given the lack of alternative cost information available and the few customers to which this applies.[95]

As customers have the option of disabling the communication function of their ADM, this fee can be avoided and applies to very few customers.

Retail costs included in notified prices

Overall, retail costs have decreased for small customers this year, in part due to the removal of legacy metering costs (which are now included in network prices, as discussed above). Retail costs have increased for large customers. The change to the annual bill for a typical customer is set out in Figures 4.5 and 4.6.[96]

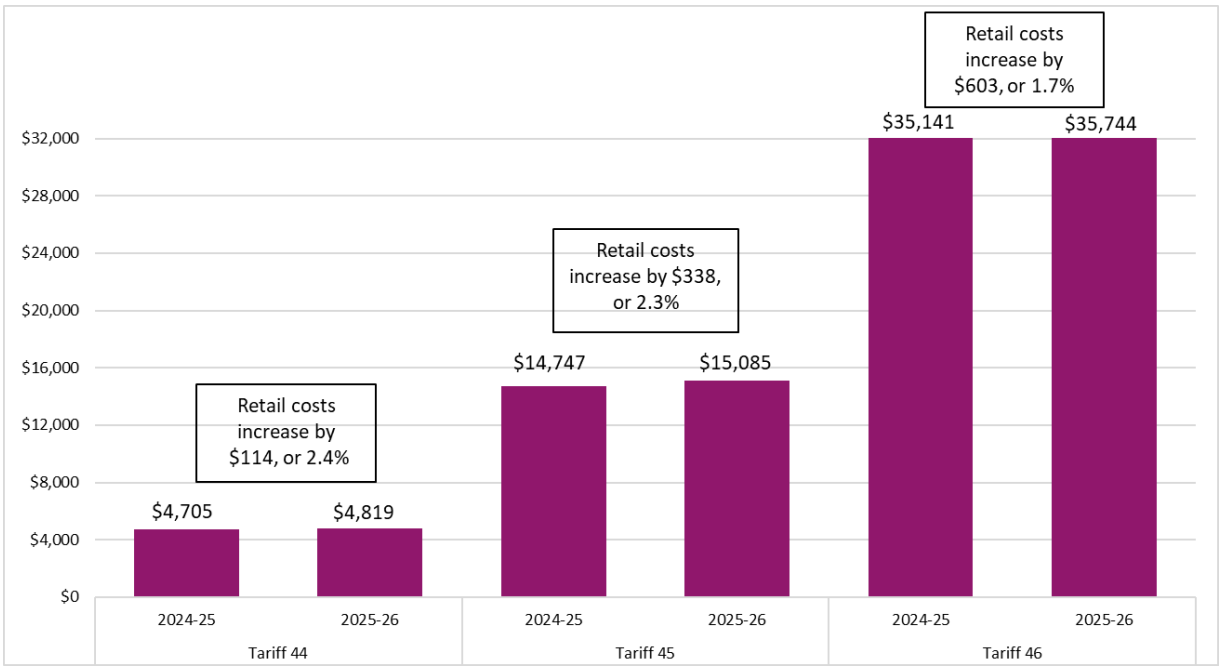
Figure 4.5: Retail costs – small customer tariffs (incl GST)



Note: The NEM fixed fees included in retail costs for 2024–25 have been removed in this figure to provide a like-for-like comparison with 2025–26 retail costs. NEM fixed fees are now accounted for in energy costs.

[94] Ergon Energy Queensland, *2025-26 network price list*, May 2025, accessed 27 May 2025.
[95] Ergon Retail has previously advised that information on costs by feeder type is not available.
[96] Amounts presented are rounded. Percentage changes are based on unrounded amounts.

Figure 4.6: Retail costs – large customer tariffs (incl GST)



Note: The NEM fixed fees included in 2024–25 retail costs have been removed to provide a like-for-like comparison with 2025–26 retail costs. NEM fixed fees are now accounted for in energy costs.

5 Other costs and pricing matters

We have considered other costs and pricing matters when setting notified prices, including the standing offer adjustment, the recovery of small-scale renewable energy scheme (SRES) costs, and the default retail tariff arrangements.

5.1 Standing offer adjustment – small customers

The standing offer adjustment (SOA) is a value incorporated into small customer tariffs, intended to reflect the value of more favourable terms and conditions in standard contracts relative to market contracts.[97]

We estimate the SOA using an established method that incorporates market information to assess the costs associated with SEQ market contracts (e.g. fees and charges a customer in SEQ may incur).[98] This market data serves as a proxy for measuring the benefits of standard contract terms and conditions for customers in regional Queensland (e.g. fees and charges they could avoid).

To do this, we used 2023–24 SEQ market data[99] to:

- assess the range of fees and charges linked to retail market contracts in SEQ
- identify any additional fees in retail market contracts compared to standard contracts
- estimate the average additional costs small customers in SEQ on market contracts could incur.[100]

Based on our assessment, small customers in SEQ on market contracts incur, on average, an additional $54.62 in fees. This amounts to around 3.35% of a small customer's annual bill.

As a result, we consider a SOA of 3.35% (of total costs) to be an appropriate value to include in small customer notified prices, subject to the DMO comparison (discussed below). The SOA has decreased slightly from last year's 3.45% due to a reduction in average retailer fees and an increase in typical annual bills for small customers in SEQ.

DMO comparison

We compare the notified price bills (including the SOA) with the DMO reference bills in SEQ to determine whether to discount the SOA – that is, when notified price bills (including the SOA) exceed the corresponding DMO reference bills for SEQ.[101]

[97] The inclusion of the SOA is consistent with the ministerial delegation and with previous reviews.
[98] The method we use was established as part of the 2021–22 notified prices review.
[99] This data reflects our most recent review of retail fees in SEQ (QCA, *SEQ retail electricity market monitoring 2023–24*, December 2024, pp 40–59).
[100] The typical annual bill for small customers is based on June 2024 data from Appendix A of the QCA's *SEQ retail electricity market monitoring report 2023-24: Appendices*.
[101] The AER sets 3 DMO reference bills for residential customers (flat-rate, flat-rate with load control, residential time-of-use) and 1 for small business customers (flat-rate). The DMO acts as a reference price to assist consumers in comparing electricity market offers and protect consumers in areas with no retail price regulation.

For the DMO comparison, we followed the same approach as last year, using the updated 2025–26 final DMO reference bills published by the Australian Energy Regulator (AER).[102] Our process included the following steps:

- **adjustments for a like-for-like comparison**:
  - including goods and services tax (GST) in the notified price bills, as GST is included in the DMO bills (but not in our notified prices)
  - using DMO consumption levels to estimate notified price bills, as consumption levels differ between our bills and the DMO bills
  - using an allocation approach to estimate a single notified price and load control bill, as the AER calculates a single DMO bill for load control tariffs, with an allocation of 29% for tariff 31 and 71% for tariff 33.
- **comparison of notified price bills** (including the 3.35% SOA) with the DMO reference bills for SEQ.

Based on this comparison, we found two relevant notified price bills exceeded the equivalent DMO reference bills (Table 5.1).

As a result, we consider it appropriate to discount the SOA included in small customer notified prices. In line with guidance from the Minister, we propose doing so in a manner that maintains the price relativity of small customer tariffs.

Accordingly, for:

- **all residential customer tariffs** – we maintained the SOA at 3.35% (reflecting that tariff 11 was lower than the relevant DMO reference bill)
- **secondary load control tariffs** – we reduced the SOA from 3.35% to 1.36% (reflecting the reduction required for tariffs 31 and 33 when compared to the relevant DMO reference bill).
- **all small business tariffs** – we reduced the SOA from 3.35% to -2.58% (reflecting the reduction required for tariff 20 when compared to the relevant DMO reference bill).

Our approach ensures that price relativity is maintained within each customer class (residential or small business). By maintaining the SOA (applying the same discount to the SOA for all tariffs within a customer class), we prevent any tariffs from becoming more attractive than others, which could distort price signals and influence customer preferences.

[102] AER, *Default market offer prices,* final determination, May 2025.

Table 5.1: DMO reference bills compared with adjusted notified price bills (incl GST)

Customer type	Notified price tariff	DMO reference bill (A)	Notified price bill, 3.35% SOA (B)	Difference (B – A)	Notified price bill, with adjusted SOA[a] (C)	Difference (C – A)
Residential	11	$2,143	$2,133	($10)	$2,133	($10)
	11+31,33	$2,425	$2,432	$7	$2,425	$0
	12B	$2,143	$2,006	($137)	$2,006	($137)
Small business	20	$4,294	$4,555	$261	$4,294	$0

a No adjustment is required to the SOA for residential tariffs.

5.2 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, SRES liabilities for the first half of the financial year are known, while liabilities for the second half are based on forecasts from the CER.[103] 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.

There was an over-recovery of SRES costs for 2024–25 – the actual SRES liabilities were lower than forecast in last year's final determination (i.e. retailers purchased fewer certificates to surrender to the CER than initially forecast).[104]

We treat the over-recovery of SRES costs as a cost pass-through in notified prices, which decreases usage charges for all retail tariffs this year.[105,106]

This approach is consistent with past reviews and remains appropriate given the existing regulatory framework, as it aligns notified prices with the UTP-consistent costs of supply.

5.3 Metering costs – large customers

Consistent with our approach in previous determinations, we have estimated large customer ADM costs for 2025–26 using confidential data EEQ provided for each large customer type.[107]

The metering charges for large customers are set out in chapter 6.[108]

[103] The CER typically determines the final SRES liabilities for the second half of the financial year about 9 months after our final determination.
[104] Reflecting the CER's final SRES liabilities for both calendar years 2024 and 2025. See Clean Energy Regulator, *Small-scale technology percentage*, CER website, 2025, accessed 17 February 2025.
[105] Cost pass-through mechanisms are used by regulators to manage the risk that forecast costs in regulated prices could be higher or lower than the efficient costs of supply. Such mechanisms are usually restricted to events outside the control of the regulated entity, such as SRES liabilities.
[106] See Appendix C for further detail on the SRES cost pass-through.
[107] In previous reviews, we also included confidential historical data from a small selection of other retailers. This information is now outdated and has not been included for this review.
[108] Metering charges for large customers are separately identified (different to small customer metering costs which are included in the small customer retail tariffs).

5.4 Default retail tariff arrangements

Under the retail tariff schedule, default tariff arrangements apply if a small customer does not nominate a tariff when they become a standard contract customer of a retailer. In this situation, the retailer must assign the customer to tariff 11 (for residential customers) or tariff 20 (for small business customers).[109] Importantly, these default tariff arrangements do not prevent a customer from later requesting assignment to another tariff.[110]

The Minister's delegation requires us to assess whether there is an ongoing need for these default tariff arrangements.[111] In the absence of stakeholder comments, and in line with our previous views, we consider there is merit in retaining these arrangements. Customers can have certainty about the retail tariff they will be assigned to if they do not nominate a tariff. This is especially important when a customer is deemed to have entered a standard contract with a retailer.[112]

5.5 Additional issues raised by stakeholders

Stakeholders commented on a range of matters not addressed elsewhere in this report. Their comments and our responses are summarised in Table 5.2.

Table 5.2: Additional issues

Stakeholder comment	QCA response
Some broader concerns include: • The consumption threshold used to classify large customers should be increased from 100 to 160 MWh.[113] • Businesses that move to a market contract should be able to return to standard contracts with EEQ if market conditions become unfavourable.[114] • The QCA should measure the economic and financial impact of electricity price increases on customers, particularly small business customers and irrigators in the Burdekin region.[115] • Information contained in large customers bills should provide a gateway to meaningful energy management.[116]	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). We encourage stakeholders to raise these broader electricity policy and regulatory matters with the Queensland Government, including the regulatory threshold for large customers and the 'non-reversion' policy for large business customers, which are set in legislation. We also encourage stakeholders to engage with their retailer about the information and resources available to assist customers to understand and manage their energy usage.

[109] However, these default arrangements do not apply where the customer's metering configuration is for a primary interruptible supply tariff, in which case the customer must expressly nominate a tariff.
[110] Queensland Government, *Gazette: Extraordinary*, no 29, vol 396, 7 June 2024, tariff schedule, p 225.
[111] Appendix A: Minister's delegation, schedule, cl 2(e).
[112] For example, a deemed customer retail arrangement can apply when a small customer starts consuming energy at a premises without applying to a retailer (i.e. a move-in customer). See ss 54–55 of the *National Energy Retail Law (Queensland)* and div 8 of the National Energy Retail Rules. A customer may be transferred to a designated retailer of last resort if their retailer becomes insolvent or has its authorisation revoked.
[113] QFF, sub 6, p. 3–4; M Gross, sub 5, p. 1; BRIG, sub 1, p. 2; Cotton Australia, sub 8, p. 4; QFF, sub 14, p 7.
[114] CPAQ, sub 2, pp 2–3, 6, 11.
[115] QEUN, sub 13, p. 2; QFF, sub. 14, p. 2–3; Giru, sub. 11, p. 1–3.
[116] QFF, sub 14, pp 6–7.

Stakeholder comment	QCA response
Some specific concerns related to network costs, pricing and terms / conditions: • Solar Bonus Scheme (SBS) charges should be itemised and, ultimately, not paid for by customers in notified prices.[117] • kVA charges should be limited to customers with: – a power factor of 0.85 – an opt-in threshold so kVA charges apply only if annual consumption exceeds 160 MWh • Queensland Government support agricultural customers with poor power factor efficiency.[118] • Customers should not be charged two daily fees.[119]	We note that jurisdictional scheme charges (including SBS charges) are included in the AER-approved network prices. These costs are treated as a pass-through (and included) in the N component for notified prices.[120] We note QFF's additional suggestions but, as discussed in chapter 3 of the main report, changes such as introducing a threshold for kVA-based charging are not consistent with the N+R methodology that we apply. We encourage QFF to raise these matters (including financial support for agricultural customers) with the Queensland Government for further policy consideration. With regard to the query about daily fees, for small customers there is only one daily supply charge for each tariff. However, large customer tariffs vary, with some having more than one charge that applies on a daily basis (i.e. separate connection and metering charges).
Stakeholders commented on consultation timeframes and materials: • Our consultation on the interim consultation paper (ICP) would be more meaningful if conducted outside the summer holiday period.[121] • The customer bill impacts should calculate bills on consumption of different households, with and without solar. Also, the QCA media releases should be widely distributed to media across regional Queensland to improve customer knowledge of decisions.[122] • Stakeholders should be able to provide verbal submissions, like that offered by the AER.[123]	We appreciate that the timing of consultation on the ICP is not ideal. However, the timeframes of our review (including the commencement date) are determined by the Minister's delegation. The ICP is the first stage of our consultation process, and stakeholders had a further opportunity to make further submissions in response to the draft determination. We send email alerts to keep stakeholders and consumer / industry groups advocates up to date with relevant milestones during our review process, including when reports or media statements are released. As such, we encourage all stakeholders to subscribe (or for consumer / industry groups to assist their members in subscribing) to email alerts via our website to receive regular review updates. This year we introduced a customer bill calculator on our website to assist customers to better understand how the upcoming change in notified prices will impact them based on their individual usage.

[117] BRIG, sub 1, p 2.
[118] QFF, sub. 6, p 6.
[119] J Gibson, sub 12, p 1.
[120] See chapter 3, which discusses the N+R framework we use to set notified prices.
[121] EVC, sub 3, p 3.
[122] QEUN, sub. 13, p. 20.
[123] QEUN, sub. 13, p. 24.

6 Notified prices

Notified prices for 2025–26 are set out by customer type in tables 6.1 to 6.11.[124]

Table 6.1: Residential customers (excl GST), 2025-26

Retail tariff	Fixed[a]	Usage			Peak demand
	(c/day)	Off-peak/ flat (c/kWh)	Shoulder (c/kWh)	Peak (c/kWh)	($/kW/mth)
Tariff 11 – residential (flat-rate)	153.493	29.975			
Tariff 12D – residential time-of-use[b]	135.304	20.618	25.486	41.556	
Tariff 12E – residential time-of-use[b]	135.304	7.022	23.977	52.148	
Tariff 14C – residential time-of-use demand[c]	115.151	20.618	25.486	22.713	7.759
Tariff 31 – night rate (super economy)		16.471			
Tariff 33 – controlled supply (economy)		17.395			

a. Charged per metering point.

b. Peak usage – 4 pm to 9 pm; shoulder (night) usage – all other times; off-peak (day) usage – 11 am to 4 pm.

c. Peak usage – 4 pm to 9 pm; shoulder (night) usage – all other times; off-peak (day) usage – 11 am to 4 pm. Demand – 4 pm to 9 pm all days.

Table 6.2: Small business and unmetered supply customers (excl GST), 2025-26

Retail tariff	Fixed[a]	Usage			Peak demand
	(c/day)	Off-peak/ flat (c/kWh)	Shoulder (c/kWh)	Peak (c/kWh)	($/kW/mth)
Tariff 20 – flat-rate	182.788	32.365			
Tariff 24A – time-of-use demand[b,d]	168.569	28.882			6.123
Tariff 24C – time-of-use demand[c]	160.673	21.510	29.053	23.348	8.095
Tariff 34 – interruptible supply	160.673	23.862			
Tariff 91 – unmetered		30.686			

a. Charged per metering point.

b. Demand – 4 pm to 9 pm on weekdays.

c. Peak usage – 5 pm to 8 pm weekdays; shoulder (night) usage – all other times; off-peak (day) usage – 11 am to 1 pm all days. Demand – 5 pm to 8 pm weekdays.

d. Tariff to be made obsolete with a 12-month phase out date.

[124] A breakdown of each notified price by cost component is provided in Appendix E. The gazette notice, which includes the notified prices published in a tariff schedule, and the terms and conditions for accessing each tariff, is provided in Appendix F.

Table 6.3: Small business customers (excl GST), 2025-26

Retail tariff	Fixed band[a]					Usage		
	Band 1 (c/day)	Band 2 (c/day)	Band 3 (c/day)	Band 4 (c/day)	Band 5 (c/day)	Off-peak/flat (c/kWh)	Shoulder (c/kWh)	Peak (c/kWh)
Tariff 22B – time-of-use inclining band[b,c]	168.569	200.006	231.443	263.084	294.621	26.085	38.128	44.496
Tariff 22C – time- of-use inclining band[b,c]	168.569	200.006	231.443	263.084	294.621	12.125	37.942	56.515

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.

c. Tariff to be made obsolete with a 12-month phase out date.

Table 6.4: Small business customers (excl GST), 2025-26

Retail tariff	Fixed (c/day)	Usage		
		Off-peak/ flat (c/kWh)	Shoulder (c/kWh)	Peak (c/kWh)
Tariff 22D – time-of-use[a]	187.464	21.510	29.053	49.946
Tariff 22E – time- of-use[a]	187.464	6.853	27.330	59.802

a. Peak usage – 5 pm to 8 pm weekdays; shoulder (night) usage – all other times; off-peak (day) usage – 11 am to 1 pm all days.

Table 6.5: Large business and street lighting customers (excl GST), 2025–26

Retail tariff	Fixed	Usage			Demand						Excess demand
		Off-peak/flat	Shoulder	Peak	Off-peak/flat[a]	Shoulder	Peak	Off-peak/ flat[a]	Shoulder	Peak	
	(c/day)	(c/kWh)	(c/kWh)	(c/kWh)	($/kW/mth)	($/kW/mth)	($/kW/mth)	($/kVA/mth)	($/kVA/mth)	($/kVA/mth)	($/kVA/mth)
Tariff 44 – over 100 MWh small (demand)[e]	4730.570	19.093			29.473			26.524			
Tariff 44A – over 100 MWh small (demand)	5673.172	19.207						23.060			
Tariff 45 – over 100 MWh medium (demand)[e]	15072.466	19.100			29.196			26.276			
Tariff 46 – over 100 MWh large (demand)[e]	39472.650	18.607			28.589			25.730			
Tariff 49 – time-of-use energy[d]	27289.156	17.179	36.691	41.569							
Tariff 50A – time-of-use demand[b,e]	19091.094	19.694								18.878	1.957
Tariff 50B – time-of-use demand[c]	5201.456	17.179	19.769	17.179		9.480	25.622		8.532	23.060	
Tariff 60A – flat-rate interruptible supply (primary)	5245.772	22.042									
Tariff 60B – flat-rate interruptible supply (secondary)		22.042									
Tariff 71 – street lighting		33.937									

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.

c. Peak usage – 5 pm to 8 pm weekdays; shoulder (night) usage – all other times; off-peak (day) usage – 11 am to 1 pm all days. Peak demand – 5 pm to 8 pm weekdays; shoulder (night) demand – all other times; off-peak (day) demand – 11 am to 1 pm all days.

d. Peak usage – 5 pm to 8 pm weekdays; shoulder (night) usage – all other times; off-peak (day) usage – 11 am to 1 pm all days.

e. Tariff to be made obsolete with a 12-month phase out date.

Table 6.6: Very large business customers (excl GST), 2025-26

Retail tariff	Fixed (c/day)	Usage (c/kWh)	Connection unit ($/day/unit)	Capacity ($/kVA of AD/mth)	Demand ($/kVA/mth)
Tariff 51A – high voltage (CAC 66 kV)	25656.277	15.057	8.331	3.586	4.414
Tariff 51B – high voltage (CAC 33 kV)	17103.977	15.057	8.331	4.679	4.565
Tariff 51C – high voltage (CAC 22/11 kV Bus)	14731.877	15.057	8.331	5.266	5.551
Tariff 51D – high voltage (CAC 22/11 kV Line)	13880.377	15.057	8.331	9.431	11.152
Tariff 53 – high voltage (ICC)	25442.947	15.057		3.586	4.414
ICC site-specific – high voltage	2877.547	12.560		0.204	0.252

Table 6.7: Very large business customers (excl GST), 2025–26

Retail tariff	Fixed	Usage		Connection unit	Capacity	Demand			Demand
		Off-peak /flat	Peak			Off-peak	Shoulder	Peak	
	(c/day)	(c/kWh)	(c/kWh)	($/day/unit)	($/kVA of AD/mth)	($/kVA/ mth)	($/kVA/ mth)	($/kVA/mth)	($/kW/mth)
Tariff 52A – high voltage (CAC STOUD 33–66 kV)[a,c]	11727.524	19.135	13.816	7.876	7.026			17.535	
Tariff 52B – high voltage (CAC STOUD 22/11 kV Bus)[a,c]	11727.524	19.135	13.816	7.876	5.041			55.956	
Tariff 52C – high voltage (CAC STOUD 22/11 kV Line)[a,c]	11727.524	19.135	13.816	7.876	9.011			66.448	
Tariff 52D – high voltage (CAC 66 kV)[b]	55404.277	13.663		8.331			3.653	6.088	2.302
Tariff 52E – high voltage (CAC 33 kV)[b]	29747.277	13.663		8.331			3.653	6.088	2.302
Tariff 52F – high voltage (CAC HV Bus)[b]	22630.977	13.663		8.331			8.066	13.442	2.302
Tariff 52G – high voltage (CAC HV Line)[b]	20076.677	13.663		8.331			11.948	19.914	2.302

a. Peak usage – summer months, off-peak usage – all other times. Chargeable demand is the maximum demand between 10am and 8pm summer weekdays.

b. Peak demand – 5 pm to 8 pm weekdays; shoulder (night) demand – all other times; off-peak (day) demand – 11 am to 1 pm all days.

c. Tariff to be made obsolete with a 12-month phase out date.

Table 6.8: Large business customers (excl GST), 2025-26

Retail tariff	Fixed (c/day)	Usage[a]	
		Below threshold (c/kWh)	Above threshold (c/kWh)
Tariff 43 – Business customer (over 100 MWh)	5673.172	21.065	18.902

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

Table 6.9: Limited-access obsolete tariffs – small business customers (excl GST), 2025-26

Retail tariff	Fixed (c/day)	Usage			Capacity	
		Block 1/ Peak (c/kWh)	Block 2 (c/kWh)	Off-peak/flat (c/kWh)	Up to 7.5kW ($/kW)	Over 7.5kW ($/kW)
Tariff 62A – time-of-use declining block tariff[a,d]	400.277	77.609	64.947	24.582		
Tariff 65A – time-of-use tariff[b,d]	400.277	60.811		31.505		
Tariff 66A – dual--rate demand tariff[c,d]	400.277			29.701	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.

d. Existing obsolete tariff with a 12-month phase out date.

Table 6.10: Existing obsolete tariffs – large business customers (excl GST), 2025-26

Retail tariff	Fixed (c/day)	Usage		Demand	
		Off-peak/flat (c/kWh)	Peak (c/kWh)	Off-peak/flat ($/kW/mth)	Peak[a] ($/kW/mth)
Tariff 50 – over 100 MWh seasonal time-of-use (demand)[b]	4211.608	22.926	16.440	12.535	85.039

a. Peak demand charged on max metered demand < 20 kW on weekdays between 10 am and 8 pm in summer (Dec, Jan and Feb). Off-peak demand charged on max metered demand < 40 kW other months (Mar to Nov). Peak usage is charged on all usage in summer months (Dec, Jan and Feb). Off-peak usage is charged on all usage during non-summer months (Mar to Nov).

b. Existing obsolete tariff with a 12-month phase out date.

Table 6.11: Metering charges – large and very large business customers advanced meters (excl GST), 2025-26

Customer type	Metering charge (c/day)
Standard asset customer (annual usage of 750 MWh or less)	216.644
Standard asset customer (annual usage greater than 750 MWh)	260.065
Connection asset customer	428.707
Individually calculated customer	374.767

Source: Retailer data.

Stakeholder submissions

We received 14 submissions during our review (available on our website).

Stakeholder	Submission number	Date received
Interim consultation paper		
Bundaberg Regional Irrigators Group (BRIG)	1	24 January 2025
Caravan Parks Association of Queensland (CPAQ)	2	24 January 2025
Electric Vehicle Council (EVC)	3	24 January 2025
Ergon Energy Queensland (EEQ)	4	24 January 2025
Gross, M	5	13 February 2025
Queensland Farmers' Federation (QFF)	6	24 January 2025
Draft determination		
Bundaberg Ag-Food & Fibre Alliance (BAFFA)	7	14 April 2025
Cotton Australia	8	23 April 2025
Ergon Energy Network and Energex	9	23 April 2025
Ergon Energy Queensland (EEQ)	10	28 April 2025
Giru Benefitted Area Irrigation Committee (Giru)	11	4 April 2025
Gibson, J	12	31 March 2025
Queensland Energy Users Network (QEUN)	13	2 May 2025
Queensland Farmers' Federation (QFF)	14	28 April 2025

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