

Regulated retail electricity prices in regional Queensland for 2026-27

Draft determination

March 2026

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Submissions

Closing date for submissions: 1 May 2026

Public involvement is an important element of our decision-making processes. Therefore, we invite submissions from interested parties. We will take account of all submissions received within the stated timeframes. Submissions, comments or inquiries regarding this paper should be directed to:

Queensland Competition Authority

GPO Box 2257, Brisbane Q 4001

Tel 07 3222 0555

www.qca.org.au/submissions

Confidentiality

In the interests of transparency, and to promote informed consultation, we intend to make all submissions publicly available. However, if a person making a submission believes that information in it is confidential, they should claim confidentiality over the relevant information (and state the basis for that claim). We will assess confidentiality claims in accordance with the *Queensland Competition Authority Act 1997*. Among other things, we will assess if disclosure of the relevant information is likely to damage a person's commercial activities, and we will consider the public interest.

Claims for confidentiality should be clearly noted on the front page of a submission, and relevant sections of the submission marked as confidential. The submission should also be provided in both redacted and unredacted versions. In the redacted version, all information claimed as confidential should be removed or hidden. In the unredacted version, all information should be exposed and visible. These measures will make it easier for us to make the remainder of the document publicly available. A confidentiality claim template is available at **www.qca.org.au/submission-policy**.

The template gives guidance on the type of information that may help us to assess a confidentiality claim. We encourage stakeholders to use this template when making confidentiality claims.

Public access to submissions

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

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1 About our review

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

On 19 January 2026, 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 2026-27.¹

We set notified prices using a well-established framework, based on factors in the Electricity Act and matters in the delegation (Box 1), stakeholder submissions² and our own analysis.

This draft determination includes indicative notified prices only. It will be updated to reflect new information in the final determination.

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.³

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

² We received 12 submissions on the interim consultation paper, which are available on [our website](#) and listed at the end of this report.

³ Electricity Act, s 90(5)(a). We may also have regard to any other matter we consider relevant (s 90(5)(b)).

1.1 Draft determination

This year, residential and small business customers are expected to see a decrease in their electricity bills, including those customers with load control tariffs. While there are changes in underlying costs, the decrease is largely driven by lower draft default market offers (DMOs) for south east Queensland (SEQ), which cap notified prices.

Large customers are expected to see an increase in their electricity bills – largely due to an increase in network costs, which are partially offset by a decrease in energy costs.

Indicative bill impacts for typical customers are discussed in Chapter 2.

As part of this year’s review, we also draw stakeholders’ attention to the new matters considered that relate to new and potential tariff options (see sections 3.1 to 3.3).

The draft notified prices are bundled prices that reflect the retail tariff structure (except for site-specific tariffs).⁴

1.2 Consultation timetable

Key dates for our review are shown in Figure 1.1.

Figure 1.1: Stages of the review



We intend to hold information sessions on key aspects of our draft determination in April 2026. Further details on these sessions, including how to register to attend, are available on [our website](#).

Stakeholders are invited to comment on our draft determination through written submissions.⁵ We will consider all stakeholder submissions we receive, along with other relevant information, when making our final determination.⁶

Submissions on the draft determination are due by 1 May 2026.

⁴ As required in cl 8 of the schedule to the Minister’s delegation. Bundled prices combine the individual cost components that make up the notified prices.

⁵ See the submissions page at the start of this report for information on making a submission, including where to access our [submission policy](#) and [online submission form](#).

⁶ We encourage stakeholders to [subscribe to our email alerts](#) to keep up to date with the project developments.

1.3 Supporting information

Supporting information available on our website includes:

- the Minister's delegation and terms of reference
- an **information booklet** that provides an overview of the key issues related to setting notified prices this year
- **appendices** to this report:
 - Appendix A: SRES cost pass-through approach
 - Appendix B: Data used to estimate customer impacts
 - Appendix C: Build-up of draft notified prices
 - Appendix D: Draft gazette notice
- reports prepared by our consultant ACIL Allen (ACIL) on:
 - energy costs (see section 4.2.1)
 - retail costs (see section 4.2.2).

1.4 Human Rights Act declaration

While our decision is economic in nature, the *Human Rights Act 2019* (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 Indicative customer bills

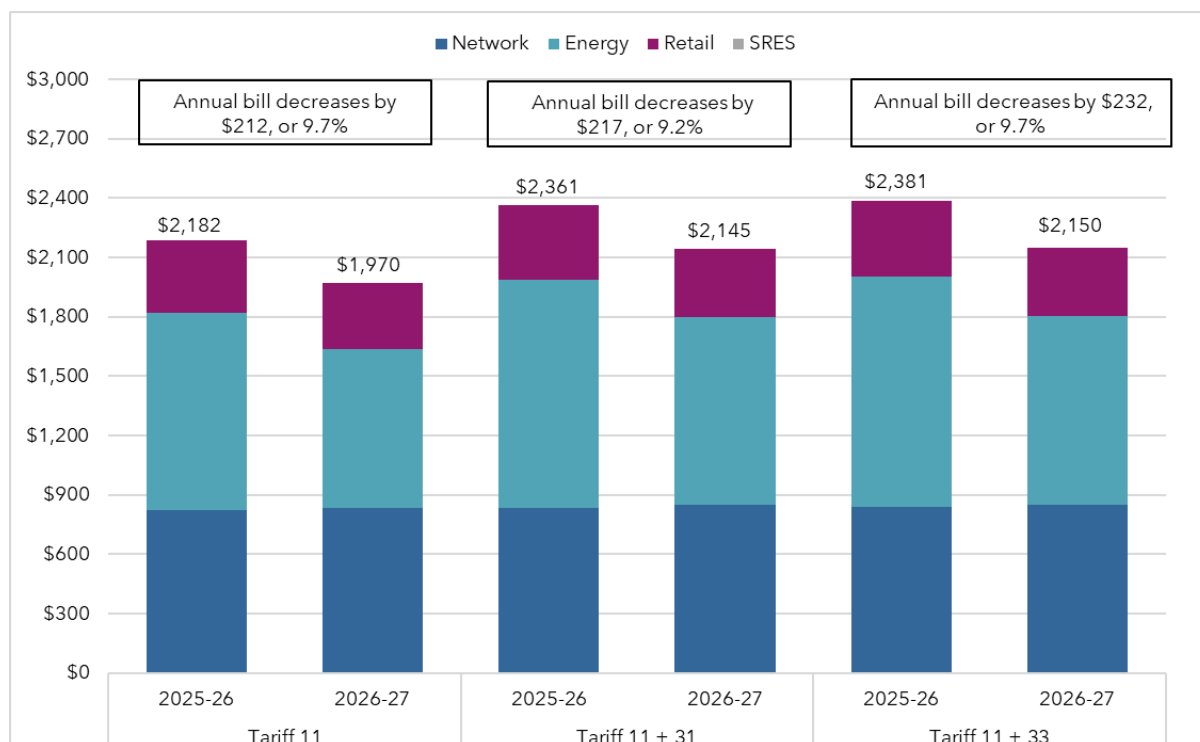
Overall, residential and small business customers can expect a decrease in their electricity bills, largely reflecting lower draft DMOs for SEQ that cap notified prices. Large customers are expected to see an increase in bills, mainly due to higher network costs.

Importantly, the draft bill estimates are for guidance only.⁷ A customer's actual bill will vary depending on their electricity consumption. For advice and further information, customers should engage with their retailer.⁸

2.1 Residential customers

Typical customers on the main residential tariff (tariff 11) are expected to pay around **9.7% less** for electricity in 2026-27 relative to 2025-26 (Figure 2.1). Customers on secondary load control tariffs (tariffs 31 and 33)⁹ can also expect bill reductions in 2026-27.

Figure 2.1: Residential customer bills, 2025-26 and 2026-27 (incl GST)



Note: SRES costs for small business customers are too small to be visible in the chart in both years. Bill changes (dollar amounts) are rounded. Percentage changes are calculated using unrounded amounts.

⁷ Customer bill impacts may change in the final determination to reflect updated cost inputs and stakeholder feedback.

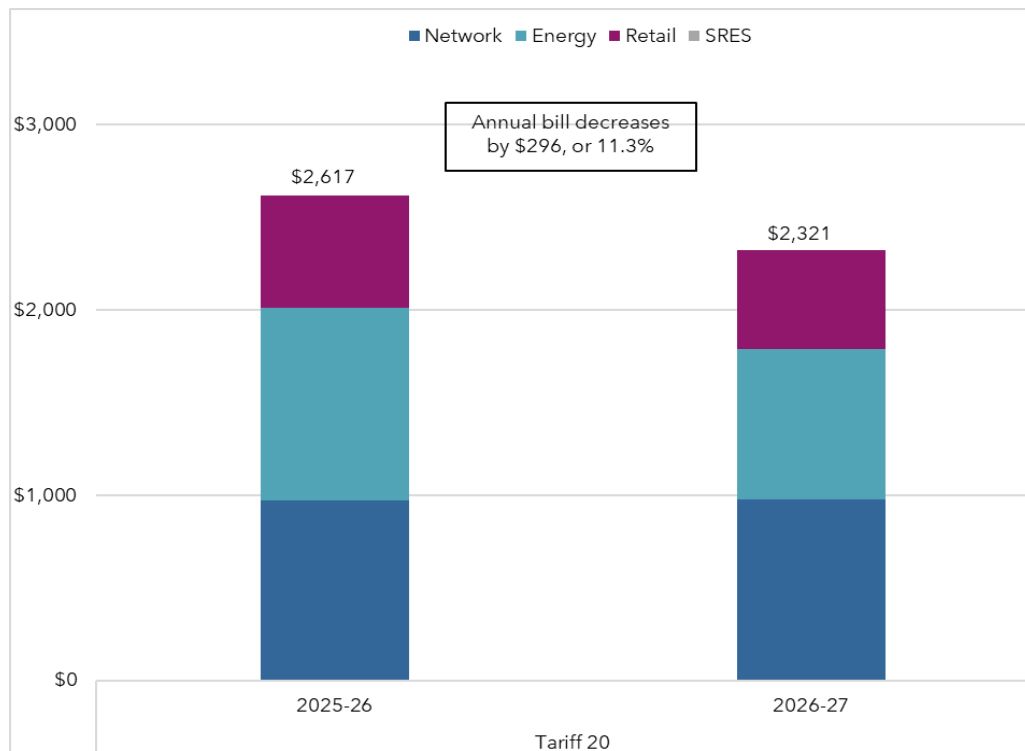
⁸ Bills are based on the consumption of a typical customer – the median customer among all regional Queensland customers on the same tariff (see Appendix B).

⁹ Tariffs 31 and 33 have interruptible supply and are often used for appliances, e.g. hot water systems and pool pumps.

2.2 Small business customers

Typical customers on the main small business tariff (tariff 20) are expected to pay around **11.3% less** for electricity in 2026–27 (Figure 2.2).

Figure 2.2: Small business customer bills, 2025–26 and 2026–27 (incl GST)



Note: SRES costs are too small to be visible in the chart in both years. Bill changes (dollar amounts) are rounded. Percentage changes are calculated using unrounded amounts.

Key drivers

Changes to notified prices reflect changes in the costs retailers incur to supply electricity. This year, while underlying supply costs have changed across tariffs, bill impacts for residential and small business customers in regional Queensland are mainly driven by the draft DMOs for SEQ, which cap notified prices.

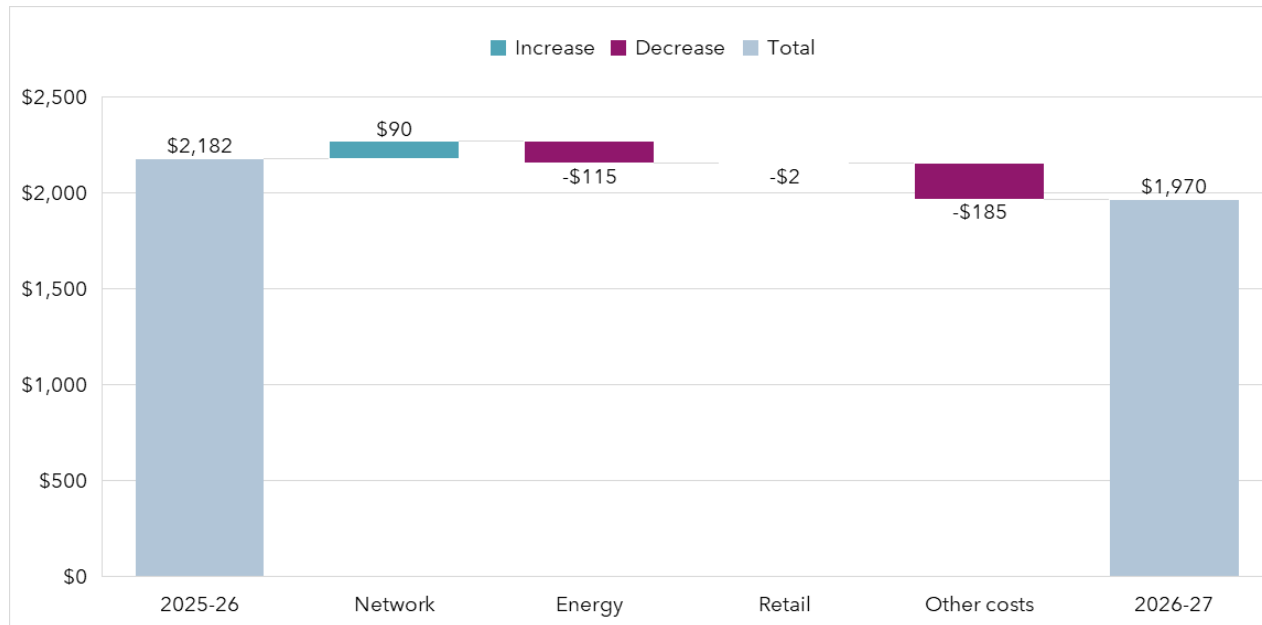
The main changes for key tariffs are:

- **tariff 11** – the main residential flat-rate tariff – **decreased**:
 - lower energy costs more than offset higher network costs, reducing the underlying cost of supply by around 1.2%
 - the draft DMO cap reduced the tariff further, resulting in a larger decrease in the typical customer bill
- **tariff 20** – the main small business flat-rate tariff – **decreased**:
 - higher network costs increased the underlying cost of supply by around 6.3%
 - the draft DMO cap reduced the tariff, resulting in a decrease in decrease in the typical customer bill

- **tariffs 31 and 33** – secondary load control tariffs – **decreased**:
 - lower energy costs reduced the underlying cost of supply.
 - the draft DMO cap reduced these tariffs further.

Figure 2.3 provides a breakdown of the individual cost components contributing to the overall bill decrease for a typical customer on tariff 11.

Figure 2.3: Tariff 11 bill – changes in cost components, 2025-26 to 2026-27 (incl GST)



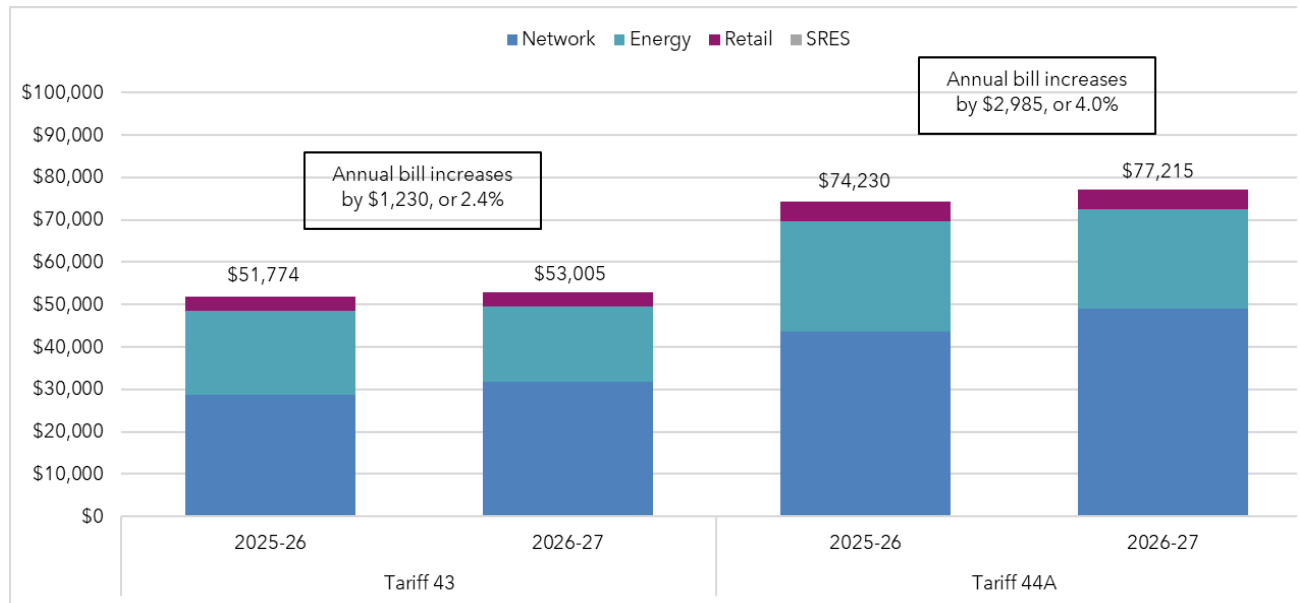
Note: Other costs include SRES and the standing offer adjustment. The standing offer adjustment is negative this year, largely due to the DMO cap (see section 5.1), and drives the overall decrease in other costs compared with last year.

2.3 Large customers

Typical large customers on tariffs 43 and 44A are expected to pay around **2.4% to 4.0% more**, respectively, for electricity in 2026-27 relative to 2025-26 (Figure 2.4).

The increase is mainly driven by an increase in network costs, which is partially offset by a decrease in energy costs.¹⁰

Figure 2.4: Comparison of large business customer bills for 2025-26 and 2026-27 (incl GST)



Note: SRES costs are too small to be visible in the chart in both years. Bill changes (dollar amounts) are rounded. Percentage changes are calculated using unrounded amounts.

¹⁰ Large customer tariffs reflect a higher share of network costs (i.e. 60-65% of total costs) compared with small customer tariffs (i.e. 45-50%). As a result, increases in network costs have a greater impact on large customer bills, all else equal. Energy costs for large customers also decreased less this year than for small customers (partly reflecting the continued uptake of rooftop solar and battery storage by small customers, which flattened their consumption profile and further reduced their energy costs). More broadly, all customers benefited from lower energy costs this year due to higher availability of Queensland coal generators, lower gas prices and increased renewable generation.

3 Overarching framework

Our approach to setting notified prices has regard to the level, structure and availability of tariffs, consistent with the Queensland Government’s uniform tariff policy and the N+R cost build-up methodology.

The framework for setting notified prices reflects the relevant provisions 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 uniform tariff policy (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. Additionally, we apply the Australian Energy Regulator’s (AER’s) default market offers (DMOs) in south-east Queensland (SEQ) to cap notified prices for small customers (see section 5.1)
- the network plus retail (N+R) cost build-up methodology – under this methodology, we treat the N component (network costs) as a pass-through and determine 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 our long-standing practice in price determinations.

Table 3.1: Overarching framework matters

Matter	Effect
Queensland Government’s UTP	<p>This means generally basing notified prices on:</p> <ul style="list-style-type: none"> • for small customers (residential and small business customers) – the cost of supplying small customers in SEQ • for large customers – the costs of supplying large customers in Ergon Energy Network’s (EEN’s) east distribution pricing zone, which is the region with the lowest supply cost connected to the National Electricity Market (NEM).
N+R cost build-up methodology	<p>This means:</p> <ul style="list-style-type: none"> • 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).

Several stakeholders have emphasised affordability as a key concern. In their submissions, industry and agricultural stakeholders commented that electricity prices materially affect operating costs and industry viability.¹¹ CPAQ similarly noted that electricity is one of the largest operating

¹¹ QCAR, sub 8, pp 3-4; Cotton Australia, sub 3, p 6; QFF, sub 12, p 2-3.

expenses for caravan and residential parks, with rising costs affecting investment decisions and regional competitiveness.¹²

QCOSS referred to our SEQ market monitoring report, noting 91% of customers in the Energex area are on cheaper market offers, so Ergon customers paying notified prices generally face higher costs. QCOSS said notified prices should be lower to be in the spirit of the UTP.¹³

We acknowledge these concerns regarding electricity prices and affordability. In setting notified prices, we have had regard to the matters specified in the Electricity Act and the Minister's delegation. We must set prices based on the costs of electricity supply. The Queensland Government's UTP is the primary mechanism through which electricity prices in regional Queensland are moderated. By applying the UTP when setting prices, notified prices are generally set below the actual cost of supply in regional Queensland, with the difference funded by the Queensland Government through a community service obligation (CSO) payment. The CSO payment was estimated to be approximately \$604 million in 2025-26.¹⁴ This reflects a policy decision by the Queensland Government to support regional customers.

For small customers, the UTP is implemented by aligning regional notified prices with the cost of supplying small customers in SEQ. As a further measure, the Minister states that we should consider the AER's DMO to be a price cap for notified prices for small customers. The DMO is a regulated price designed to protect standing offer customers and serve as a comparison price for market offers.

Accordingly, while many SEQ customers may be on discounted market offers below the DMO, the UTP does not require that notified prices in regional Queensland match the cheapest market offers available in SEQ. Rather, it seeks to ensure that customers of the same class have access to similar price structures and that regional customers do not pay more than the relevant regulated benchmark in SEQ.

Stakeholders also raised concerns regarding tariff structures, including the level of daily supply charges, demand charge tariff components and the alignment of time-of-use windows with periods of solar generation and flexible load operation.¹⁵ Under the N+R framework, we pass through network tariff structures, including fixed charges, time-of-use windows and eligibility conditions, as approved by the AER, unless the Minister directs us to consider creating new or modified retail tariffs to meet broader policy objectives. Our discretion to alter those structures is therefore limited.

While we acknowledge the importance of the issues raised by stakeholders, broader structural reform or the introduction of additional support measures falls outside the scope of this price determination.

Customers experiencing financial hardship are encouraged to contact their retailer to discuss available assistance options. Key support measures available are outlined in Box 2.

¹² CPAQ, sub 2, p 1.

¹³ QCOSS, sub 10, Etrog report, p 7.

¹⁴ Queensland Government, *Budget Strategy and Outlook*, Paper 2, Queensland Budget 2025-26, June 2025, p 153.

¹⁵ Hardwick, sub 6, p 1; Cotton Australia, sub 3, p 4; Canegrowers, sub 1, pp 3-4; CPAQ, sub 2, pp 3-4; QFF, sub 12, pp 2-3.

Box 2: Customer support measures in regional Queensland

Customers facing payment difficulties should contact their retailer to find out what support is available.

Retailer hardship obligations

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

Ergon Energy Retail's [Customer Assist program](#) provides support to eligible customers experiencing financial hardship, including by offering payment plans.

Government concessions and assistance programs

A range of Queensland Government initiatives are available to eligible households and businesses, including:

- electricity [rebates](#) for eligible pensioners and seniors
- the [Home Energy Emergency Assistance Scheme](#) provides one-off emergency assistance to households experiencing difficulty paying their electricity bills due to an unforeseen emergency or short-term financial crisis in the previous 12 months
- 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.
- the [ecoBiz program](#) assists small to medium-sized businesses reduce energy costs through benchmarking, action planning and on-site coaching. Further information on [energy concessions](#) and [support for businesses](#) can be found on the Queensland Government's website.

Additional resources

Stakeholders may also refer to:

- [Queensland Farmers' Federation website](#) for information and resources on electricity prices, understanding bills, government schemes and industry specific programs
- Ergon Energy Retail's website for information to assist [households](#), [businesses](#) and [farmers](#), including tariff options and support programs.
- The [Australian Government's energy.gov.au website](#) for information on how to improve energy efficiency (for households and small businesses) and access rebates across jurisdictions, including Queensland.

Dispute resolution

Customers can contact the [Energy and Water Ombudsman Queensland](#) for information on how to lodge a complaint or resolve a dispute involving their electricity, gas or water supplier.

3.1 Assessment of new tariffs

3.1.1 Large customer 'solar soaker' tariff

The delegation asks us to consider creating a new 'solar soaker' time-of-use (TOU) tariff for large customers.

A solar soaker tariff is based on an existing network tariff and incorporates time-varying wholesale energy costs to create stronger price differences between peak and non-peak periods. This can encourage customers to shift consumption into non-peak periods to take advantage of lower usage charges. In recent years, a solar soaker TOU tariff has been available for residential customers (tariff 12E) and small business customers (tariff 22E).¹⁶

Stakeholder comments

Stakeholders generally supported introducing a large customer solar soaker tariff, provided it was structured appropriately:

- Cotton Australia said the 'solar soaker' period should reflect genuine periods of solar abundance, like the off-peak period for the residential TOU tariffs. It considered the off-peak period for standard business TOU tariffs (such as tariff 49) inadequate and too unattractive to induce user change. Cotton Australia did not support using tariff 49, including because it has a high daily supply charge and conditions relating to the minimum demand and maximum consumption levels. It proposed further consultation on the proposed structure of this tariff prior to the draft determination.¹⁷
- QFF said the tariff should have a daily supply charge that is not cost prohibitive, suitable peak, shoulder and day TOU windows, and rates that encourage utilisation during mornings, shoulder and night times.¹⁸
- EEQ recommended that the solar soaker tariff replace tariff 49, given its similar structure. It noted tariff 49 currently has no customers because the high daily supply charge makes it unattractive.¹⁹

Draft decision

Some stakeholders proposed that the solar soaker tariff should have a different tariff structure or different terms and conditions than the underlying network tariff. However, under the N+R framework, retail tariffs reflect the structure and terms of the relevant network tariff unless the Minister directs us to consider deviations based on stated policy objectives.

The purpose of introducing a solar soaker tariff is to provide an alternative TOU option with stronger pricing signals, achieved by varying the wholesale energy cost component across TOU periods. It is not intended to modify the underlying network tariff structure.

Accordingly, the solar soaker tariff must be based on an existing network tariff. Therefore, we cannot:

¹⁶ Section 4.2.1 explains how we determine time-varying wholesale energy costs.

¹⁷ Cotton Australia, sub 3, p 4.

¹⁸ QFF, sub 12, p 3.

¹⁹ EEQ, sub 4, p 1.

- introduce TOU windows that differ from those in the relevant network tariff, even if doing so would make the tariff more attractive for potential users. These windows were developed by the Queensland distribution businesses as part of their network tariff strategies and have been approved by the AER
- modify network pricing structures and charges. For instance, stakeholders identified the relatively high daily supply charge for tariff 49 as a barrier to using this tariff as the basis for a solar soaker tariff. However, this charge reflects approved network charges, which retailers must pay, and therefore it must be reflected in the retail tariff.

We considered basing the new solar soaker tariff on the structure of:

- tariff 49, which has TOU usage charges and a daily supply charge but is limited to customers with monthly peak demand greater than 120 kVA and annual consumption below 160 MWh, or
- tariff 50B, which includes TOU usage charges, TOU demand charges and a daily supply charge.

Stakeholders indicated that tariff 49 may not be an effective basis for a solar soaker tariff, including due to its relatively high daily supply charge and eligibility conditions that limit customer access.

Subject to further stakeholder submissions, we have decided to base the new solar soaker tariff on the underlying network tariff for tariff 50B. The new tariff will be designated tariff 50C. While tariff 50B is more complex than tariff 49 (as it includes demand charges), large customers are generally sophisticated electricity users and are familiar with demand-based charges.²⁰ In addition, tariff 50B does not have the demand and consumption eligibility requirements that apply to tariff 49; therefore, the solar soaker tariff would apply to a broader range of large customers.

Under this approach, time-varying wholesale energy costs will apply only to the TOU usage charges. They will not apply to the TOU demand charges, which primarily reflect network charges.

3.1.2 Electric vehicle (EV) tariff proposal

The delegation includes a new process for EEQ to submit an EV tariff proposal that we must assess and decide whether to approve (and publish the tariff) as part of the notified prices final determination.

In making this assessment, we must have regard to the matters set out in the Electricity Act that apply when making a price determination.²¹

The Minister has advised that the proposed EV tariff does not need to satisfy the N+R framework that applies to other retail tariffs. Instead, our assessment must consider:

- if the EV tariff can be offered under a standard retail contract
- the tariff rates that should apply based on what could reasonably be offered by a retailer in the SEQ electricity market.

The delegation also requires that EEQ's tariff proposal include a commitment that consultation with Queensland Treasury has occurred on any potential community service obligation implications.

²⁰ We note that in accordance with the relevant network tariff structure, demand charges will not be payable for usage within the off-peak period.

²¹ These matters are set out in Box 1, Chapter 1.

On 23 February 2026, EEQ submitted its EV tariff proposal.²² A summary of the proposal is outlined in Box 3. Due to timing constraints, we could not seek and consider submissions on EEQ's proposal before publishing this draft determination.

Box 3: Outline of EEQ's EV tariff proposal

The proposed EV tariff would operate as a TOU tariff that provides a discounted usage charge (in the form of a bill adjustment) for electricity used during eligible EV scheduled charging sessions.

The TOU windows would be the same as those used for the other standard retail TOU tariffs.²³ While EEQ has not proposed a specific tariff rate, it indicated the rates for each TOU window would be structured as follows:

- **peak:** charged at the customer's primary tariff rate
- **shoulder:** charged at a discounted 'EV charging usage rate'
- **off-peak:** charged at the same discounted 'EV charging usage rate' as the shoulder period.

EEQ recommended the rate should be no more than tariff 31 (a small customer load control tariff) and aligned with what retailers in the SEQ market reasonably offer.

Under the proposal, all electricity usage would continue to be billed under the customer's primary tariff (such as tariff 11 or another TOU tariff). However, energy consumed during eligible EV scheduled charging sessions would receive a credit on the customer's bill equal to the difference between the primary tariff usage rate and the EV usage rate (where the EV rate is lower).

Customers would access the tariff by using the retailer's systems to initiate and schedule EV charging. We understand this would occur through a retailer-provided mobile application, which would require the customer to enrol an EV or EV charging device.

The tariff would require customers to have compatible charging equipment or systems capable of communicating with the retailer, including through an internet connection or another mechanism that allows communication with the retailer.

The tariff would be available only to residential customers on an opt-in basis (i.e. not mandatory for customers with EVs).

Stakeholder comments

As stakeholders could not consider the detailed EV tariff proposal before making submissions, stakeholder feedback was limited.

Stakeholders generally supported introducing an EV tariff, subject to further consultation²⁴, noting that the delegation allows innovation in designing the tariff by specifying that the tariff does not

²² The proposal is available on our website: [Regulated electricity prices for regional Queensland 2026-27](#).

²³ Peak: 4-9 pm; day (off-peak): 11 am - 4 pm; night (shoulder): all other times.

²⁴ Queensland Consumers' Association, sub 9, pp 1-2; QCOSS, sub 10, Etrog report, p 3; EEN and Energex, sub 5, p 1.

need to comply with the N+R framework.²⁵ Other stakeholders said any such tariff should have a broader application beyond EV charging and be designed to reflect the preferences of agricultural users.²⁶

Draft decision

Under the Minister's delegation, our task is to decide whether to approve EEQ's EV tariff, having regard to the relevant decision-making factors in the Electricity Act and the requirements of the delegation.

While we will consider stakeholder views when making the decision about whether to approve the tariff proposal, our role is not to redesign or amend the proposed tariff to reflect stakeholder preferences. Furthermore, we note that the Minister's delegation clearly contemplates that this tariff be an EV tariff for residential customers and does not indicate that the tariff should have a broader application or be available to business customers.

We note that EEQ's tariff proposal does not specify a tariff rate, instead stating that we should determine a rate between what is reasonably offered in SEQ and tariff 31. The proposal also indicates EEQ intends to consult with Queensland Treasury on the CSO implications at a later stage.

We consider that the proposal should include a specific rate and confirm that consultation with Queensland Treasury has occurred. This would allow us to assess the rate, including the consistency with what could be reasonably be offered by a retailer in the SEQ.

We therefore request that EEQ submit a revised proposal that includes a specific tariff rate and confirms the relevant consultation with Queensland Treasury has occurred.

Given timing constraints, we have not yet assessed the broader tariff arrangements against the Electricity Act and Minister's delegation. We intend to undertake this assessment as part of the final determination, subject to the timing of any revised tariff proposal.

We also seek further information from EEQ on how electricity usage data for EV scheduled load will be metered and used for billing purposes, including how this aligns with any applicable electricity laws, regulations and the standard retail contract.

We invite stakeholder views on EEQ's tariff proposal, including whether it contains sufficient protections for consumers and the other matters we have raised above.

3.1.3 Dynamic flex storage tariffs

In last year's review, we updated regulated retail tariffs to reflect the new network tariffs approved by the AER from 1 July 2025. This resulted in the phasing out of several existing retail tariffs and the introduction of new retail tariffs based on new network tariff structures.

However, we did not introduce retail tariffs based on the new dynamic flex storage network tariffs for large customers and connection asset customers (CAC) (see Box 4). This was due to time constraints and uncertainty regarding the potential use of these tariffs at the time of our determination.²⁷

²⁵ Canegrowers, sub 1, pp 1-2.

²⁶ QFF, sub12, pp 3-4; Canegrowers, sub 1, pp 3-4; Cotton Australia, sub 3, pp 4-5; QCAR, sub 8, p 5.

²⁷ QCA, *Regulated retail electricity prices 2025-26*, final determination, June 2025, p 14.

Box 4: Dynamic flex storage tariffs

Dynamic flex storage tariffs apply to importing electricity for the sole purpose of exporting it back to the network. Each tariff includes TOU usage charges (with only usage during the peak period subject to network charges) and a daily supply charge.

Under the network tariff arrangements, customers must have a dynamic connection agreement²⁸ with the distributor to be eligible for these tariffs. Customers with storage connected to solar photovoltaic (PV) systems, or with additional load behind the same connection point, are not eligible.²⁹

Importantly, these tariffs apply only to charges for imported electricity and do not include prices for exported electricity.

Draft decision

Under the N+R framework, we would typically introduce a retail tariff that reflects an approved network tariff. However, the dynamic flex storage tariffs are a new and highly specialised tariff type, intended for a specific and limited use rather than general customer application.

We therefore considered whether there is likely to be sufficient demand for these tariffs in 2026–27 to justify introducing a corresponding retail tariff.

Stakeholders did not provide submissions on this matter, and we are not aware of any current demand for this type of tariff.

Subject to stakeholder submissions, we do not propose to introduce retail tariffs based on the dynamic flex storage network tariffs at this stage. Without evidence of likely uptake, introducing these tariffs would create administrative costs and implementation burdens for retailers with little or no expected benefit to customers.

If demand for these tariffs emerges in the future, we can reconsider introducing them in a future determination.

3.2 Consultation on potential future tariffs

3.2.1 Solar sharer offer (SSO)

In March 2026, the Australian Government amended the DMO regulations to, among other things, establish an SSO for standing offer customers as part of the AER's DMO process.³⁰ This followed the publication of the Australian Government's SSO consultation outcome paper in January 2026, which outlined its proposed approach to the design and implementation of the SSO retail

²⁸ EEN, *Explanatory statement: Revised Regulatory Proposal 2025–30*, November 2024, p 45.

²⁹ EEN, *Tariff Structure Statement: Regulatory Determination Proposal 2025–30*, November 2024, as amended and approved by the AER, April 2025, pp 25–26.

³⁰ Competition and Consumer (Industry Code–Electricity Retail) Amendment Regulations 2026.

product.³¹ The SSO will be available from 1 July 2026 in areas covered by the DMO (New South Wales, South Australia and SEQ).

The SSO is a residential TOU tariff that will provide customers with a zero-cost electricity period for 3 hours during the day (up to a reasonable use cap), aligning with periods of high rooftop solar generation and low wholesale and network costs in the electricity network.

The Minister has asked us to consult with stakeholders on the suitability of establishing a regulated zero-cost electricity period offer for residential customers in regional Queensland.

Stakeholder comments

Most stakeholders generally support the concept of solar-aligned tariffs in principle – particularly where the tariffs encourage load-shifting and reflect periods of high solar generation. However, stakeholders raised several concerns regarding the design, implementation and distributional impacts of a regulated zero-cost electricity period.

EEQ said the SSO should be available to all small customers with smart meters, and we should publish clear and accessible customer information explaining how the tariff operates.³² Similarly, QCOSS emphasised the importance of opt-in participation, simple tariff structures and clear customer communication.³³

Retailers said any SSO would need to ensure full recovery of underlying electricity supply costs:

- EEQ supported availability of an SSO from 1 July 2026 but noted that wholesale, AEMO, environmental and network costs incurred during the ‘free’ period would still need to be recovered. EEQ also highlighted challenges associated with the proposed implementation timeframe.³⁴
- Origin did not support a regulated zero-cost electricity period, noting that electricity is not costless at any time of day and retailers must recover wholesale, network and operating costs to ensure market stability and efficient pricing signals. Origin also noted that products marketed as ‘free energy’ typically recover costs through higher charges in other periods or through usage limits.³⁵

Several stakeholders also raised concerns about potential equity and bill impacts:

- EEQ highlighted the risk of bill shock for customers unable to shift electricity use to the free period and noted that some customers may face inequitable outcomes if they cannot alter their consumption patterns.³⁶
- Origin noted that customers unable to shift load – particularly renters and lower-income households – could be worse off if higher charges apply outside the free period.³⁷
- QCOSS raised broader equity concerns, including potential disparities between customers in the Energex and Ergon distribution areas, the possibility that benefits may primarily accrue to households with batteries, and barriers for customers without smart meters. QCOSS also recommended safeguards to prevent unfair cost recovery.³⁸

³¹ Australian Government, Department of Climate Change, Energy, the Environment and Water, [Solar Sharer Offer consultation outcomes paper](#), January 2026.

³² EEQ, sub 4, pp 1-2.

³³ QCOSS, sub 10, Etrog report, p 3.

³⁴ EEQ, sub 4, pp 1-2.

³⁵ Origin, sub 7, pp 1-2.

³⁶ EEQ, sub 4, pp 1-2.

³⁷ Origin, sub 7, pp 1-2.

³⁸ QCOSS, sub 10, Etrog report, pp 2-3.

- QEUN emphasised the need for transparency around the modelling used to support the introduction of the SSO due to the potential impacts on bills.³⁹

QCOSS and the Queensland Consumers' Association considered that regional Queensland customers should have access to a solar sharer tariff option if the SSO is introduced in SEQ. They said a solar sharer tariff should be included in the draft determination so that stakeholders can provide feedback and should then be incorporated into the final determination pending national developments and the AER's DMO.⁴⁰

Draft decision

We appreciate stakeholders' views on the potential introduction of an SSO. These views may assist the Minister and the Queensland Government in considering whether, and how, such a tariff might be introduced in regional Queensland in the future, noting the Minister has not asked us to establish a solar sharer tariff as part of this determination.

The AER has only recently released its draft DMO determination, which includes its consideration of matters relevant to the setting of the SSO for SEQ. The timeframe for our draft determination has constrained our ability to fully assess the detailed design and operation of the SSO, undertake modelling, evaluate bill impacts, or provide stakeholders with the level of detail they have requested as part of the draft determination.

We therefore intend to provide our analysis of issues that may be relevant for introducing a solar sharer tariff in regional Queensland in our final determination. Any future implementation would require specific policy direction from the Minister and would potentially be informed by the design of any equivalent product introduced in SEQ.

3.2.2 Small to large customer transitional tariff

Small customers are defined in Queensland legislation as customers that consume less than 100MWh of electricity annually. These customers generally access simpler tariffs, often based on a fixed daily charge and an energy usage charge (c/kWh). The most common small business customer tariff accessed in regional Queensland is the flat-rate tariff 20.

Once a small business customer consumes more than 100 MWh annually, they are classified as a large customer and move onto more cost-reflective large customer tariffs, which typically include daily charges, usage charges and demand charges. This can lead to a sharp bill increase, primarily because of the higher large customer prices, as well as the more complex demand-based tariff structures.

The Minister asked us to consult with stakeholders on a possible new tariff that could assist small business customers transition to large customer tariffs when their usage exceeds 100 MWh per year and they are reclassified as a large customer.

The Minister also indicated the tariff could include fixed, usage and demand charges, with rates set so that a typical customer using 100 MWh annually would see only a minimal bill increase. Rates would escalate so that a customer using 160 MWh annually would pay a similar amount to a typical customer on tariff 44A.

³⁹ QEUN, sub 11, pp 1-2.

⁴⁰ QCOSS, sub 10, p 1; Queensland Consumers' Association, sub 9, p 2.

Stakeholder comments

Stakeholders identified the legislated 100 MWh annual consumption threshold that separates small and large customers as the core issue requiring reform and expressed a preference for this threshold to be raised to 160 MWh instead of the introduction of a transitional tariff. In particular:

- Canegrowers said the current threshold creates a pricing 'cliff', resulting in disproportionate bill increases that are not reflective of underlying cost changes. It considered raising the threshold would directly address the 'root cause of customer detriment'.⁴¹
- Cotton Australia and QFF supported increasing the threshold to 160 MWh to reduce complexity, improve productivity and encourage network use by customers with seasonal or intermittent demand.⁴²

CPAQ supported the introduction of a transitional tariff but emphasised the importance of clear communication, proactive customer notification and sufficient lead time to ensure eligible businesses understand and can access the tariff.⁴³

EEQ also supported creation of a transitional tariff but noted that further detail would be required regarding tariff design, including the pricing glidepath, eligibility criteria, duration and how any cost under-recovery would be managed (particularly where many customers use the transitional tariff).⁴⁴

Draft decision

The Minister's delegation asks us to consult on a potential transitional tariff, rather than to introduce such a tariff as part of this review. The Minister also indicated a broad tariff concept involving a new transitional tariff with a fixed, usage and demand charge and an inclining rate profile between 100 MWh and 160 MWh.

Developing a practical tariff option would require detailed information on the relevant customer cohort, including the number of customers affected and their consumption and demand characteristics within the 100-160 MWh range. This information is primarily held by retailers, including EEQ.

As this tariff cannot be set under the usual N+R method and pricing framework, any future implementation would require specific policy direction from the Minister, including on the tariff scope, customer eligibility and duration of the tariff. When developing the policy for any proposed transitional tariff, consideration should also be given to the potential competition impacts the tariff may have in the retail electricity market for large customers and any equity considerations for large customers that have previously switched to a market offer and cannot revert to EEQ due to the legislated non-reversion policy.

However, further to some of the issues raised by EEQ regarding tariff scope and design, we have provided a preliminary assessment of:

- considerations that may be relevant to designing a transitional tariff
- broader matters that may be relevant to consider before the tariff is implemented.

⁴¹ Canegrowers, sub 1, pp 1-2.

⁴² Cotton Australia, sub 3, p 5; QFF, sub 12, pp 4-5.

⁴³ CPAQ, sub 2, pp 5-6.

⁴⁴ EEQ, sub 4, p 2.

Transitional tariff design

Designing a transitional tariff involves both policy and practical considerations. Defining the objective of the tariff and the customer cohort it is intended to support will assist and inform tariff design, eligibility settings and duration.

For example, if a transitional tariff is intended to operate as a temporary bridge between small and large customer tariffs, eligibility and duration settings would need to ensure customers eventually move to standard large customer tariffs. Alternatively, if the tariff applies more broadly to customers whose consumption remains between 100 and 160 MWh, it may operate more like an ongoing tariff class.

These considerations may influence the intended scope of the tariff, potential CSO implications and broader market impacts. They may also affect practical implementation of the tariff by retailers.

Table 3.2 summarises several information requirements and design considerations that may be relevant to the development of a transitional tariff in future.

Table 3.2: Key information required to design a transitional tariff

Issue	Information description
Glidepath design	<ul style="list-style-type: none">• How demand charges would be introduced (e.g. starting at \$0 and increasing)• Whether rate escalation would occur over time or only when customers meet specified usage bands between 100 and 160 MWh
Eligibility	<ul style="list-style-type: none">• Which customers would be eligible (e.g. customers that have only recently been reclassified as large customers or all customers within the 100–160 MWh band)
Duration	<ul style="list-style-type: none">• How long customers would remain eligible (e.g. fixed period, until 160 MWh is reached, or until consumption stabilises)
Interaction with network tariffs	<ul style="list-style-type: none">• Whether the tariff would be linked to an existing network tariff or operate as a retail-derived tariff• How network cost recovery risks would be managed
Bill impact targeting	<ul style="list-style-type: none">• Which load profiles and demand levels would be used to assess the impact on bill outcomes for consumption between 100 and 160 MWh
Implementation considerations	<ul style="list-style-type: none">• Retailer billing capability, metering requirements and administrative processes for moving customers onto and off the tariff

Other considerations

Potential CSO implications

A key design consideration is the potential for a permanent transition outcome, where some customers exceed the 100 MWh threshold but never approach 160 MWh if their consumption stabilises at a lower level. As a result, the transitional tariff would effectively operate as a de facto threshold change without a corresponding legislative amendment.

The implications of this outcome should be considered in light of the intended policy objective.

Depending on how eligibility is defined, a transitional tariff could also apply to a substantial proportion of large customers in regional Queensland.

Based on customer usage data, around half of large customers consume less than 160 MWh annually. If eligibility is broadly defined (for example, if the tariff applies to all customers within the 100-160 MWh band), the tariff could apply to a large share of the large customer population. This may have implications for:

- the scale of any associated subsidy arrangements
- the size of the beneficiary cohort
- the long-term fiscal exposure associated with the tariff.

Competition and market impacts

Introducing a regulated transitional tariff may affect competition in the large customer electricity market segment in regional Queensland. If the regulated price level for customers in the 100-160 MWh band is reduced, this may:

- reduce the attractiveness of existing market offers
- weaken incentives for retailers to compete for these customers.

This highlights a trade-off between supporting customers during reclassification and maintaining competitive pressure in the large-customer market.

Equity considerations

If the transitional tariff is introduced into notified prices, this may create differences in access to a transitional tariff between otherwise similar customers. For example, large customers that have switched to a market offer will not be able to return to EEQ under the existing legislated non-reversion policy.

Duration and phase-out considerations

A key design issue is specifying the duration of the tariff. Once the tariff is introduced, it may be difficult to remove, particularly if a large group of customers benefit from the arrangement. Possible approaches to defining duration could include:

- time-limited eligibility, i.e. customers can only stay on the transitional tariff for a fixed time
- usage-based exit triggers, i.e. after a customer's consumption reaches 160 MWh, customers move to a standard tariff and are not eligible to access the transitional tariff in future
- cohort-based sunset provisions, i.e. the tariff applies to a specific group of customers for a set time-period (after which no new customers access the tariff)
- scheduled policy review points, i.e. the government reviews the arrangements at set time intervals to decide whether the tariff continues, changes or is removed.

Clearly defining duration would help ensure the tariff operates as intended and does not become a permanent customer class (if that is not the intended objective).

Implementation by retailers

Implementing a transitional tariff would involve practical considerations for retailers, including billing system capability, eligibility monitoring and processes for moving customers onto and off the tariff, and between usage bands.

These operational matters would likely need to be addressed by retailers, including Ergon Energy Retail, before the tariff is implemented.

3.3 Other tariff matters

3.3.1 Transition and expiry of obsolete tariffs

A number of obsolete retail tariffs⁴⁵ are scheduled to expire on 30 June 2026 (see Table 3.3). The delegation requires us to consider whether these tariffs should be phased out as scheduled or be extended into 2026–27.

Table 3.3: Existing obsolete tariffs scheduled to expire on 30 June 2026

Small business tariffs	Large customer tariffs
Tariff 22B (TOU inclining-band tariff)	Tariff 44 (demand (small threshold) tariff)
Tariff 22C (TOU inclining-band tariff) (solar soaker tariff variant)	Tariff 45 (demand (medium threshold) tariff)
Tariff 24A (TOU demand tariff)	Tariff 46 (demand (large threshold) tariff)
Tariff 62A (limited access obsolete TOU declining-block tariff)	Tariff 50 (seasonal TOU demand tariff)
Tariff 65A (limited access obsolete TOU tariff)	Tariff 50A (TOU demand tariff)
Tariff 66A (limited access obsolete fixed dual-rate demand tariff)	Tariff 52A (seasonal TOU demand tariff for CAC supplied at 33 or 66 kV)
	Tariff 52B (seasonal TOU demand tariff for CAC supplied on an 11 or 22 kV bus)
	Tariff 52C (seasonal TOU demand tariff for CAC supplied on an 11 or 22 kV line)

Most of these tariffs were made obsolete in our determination of 2025–26 notified prices following changes to the underlying network tariffs approved by the AER.⁴⁶ At that time, the tariffs were made obsolete with a 12-month phase-out period to allow affected customers time to understand the changes, alternative tariff options and adjust usage if required, while limiting the period during which retail tariffs were misaligned with network tariffs.

Stakeholder comments

Stakeholders generally supported allowing most obsolete tariffs to expire as scheduled,⁴⁷ with a few exceptions:

- **Small business solar soaker tariff 22C** – QFF, Canegrowers and Cotton Australia considered tariff 22C (the small business ‘solar soaker’ tariff with obsolete TOU windows) should be retained as a standard tariff or replaced with a similarly structured tariff. They said the tariff provides useful price signals and sufficiently wide TOU windows to encourage

⁴⁵ Obsolete tariffs are only available to customers on the tariff when it became obsolete. Customers who move to another tariff cannot return to the obsolete tariff.

⁴⁶ QCA, *Regulated retail electricity prices 2025–26*, final determination, June 2025, pp 10–13.

⁴⁷ EEQ, sub 4, p 3; Cotton Australia, sub no 3, p 5; QFF, sub 12, pp 5–6.

behavioural change, particularly for agricultural users who have adjusted operating schedules or invested in technology to adapt to this tariff.⁴⁸

- **Limited access irrigation tariffs 62A, 65A and 66A** – Ergon Energy Retail supported continuing these tariffs, noting that some customers currently on these tariffs have expressed a preference for their retention. However, it also noted some customers on these tariffs may achieve savings on alternative tariffs.⁴⁹

QFF, Canegrowers and Cotton Australia did not oppose the scheduled phase out of these tariffs.⁵⁰ QFF considered the tariffs do not provide meaningful benefits or reflect contemporary system conditions, while Canegrowers considered they are poorly aligned with current network cost structures and do not provide clear or effective price signals to support efficient electricity use.⁵¹

Draft decision

We consider the scheduled phase-out date for obsolete tariffs should only be extended where operational or practical constraints make it difficult for customers to transition to standard tariffs.

Affected customers were provided 12 months to transition following the 2025–26 determination. We consider this period was sufficient for customers to understand their alternative tariff options and adjust their usage if necessary. This is particularly the case for large customers, who are generally sophisticated electricity consumers.

Some stakeholders expressed a preference to retain tariff 22C, primarily because its TOU windows are wider than those introduced under last year’s network tariff reforms. However, the TOU windows for tariff 22C are no longer reflected in the relevant underlying network tariffs. Under the N+R framework, retail tariffs should align with the structure of the underlying network tariffs as soon as practicable.

We note Ergon Energy Retail’s suggestion that the phase-out date for tariffs 62A, 65A and 66A be extended. However, these tariffs have already had an extended transition period, with the process of phasing them out originally commencing in 2012–13.⁵² In our view, a further extension is not warranted.

3.3.2 Access requirements for tariffs 60A and 60B

Access to tariffs 60A and 60B (the large customer load control tariffs) is limited to only those parts of Ergon Energy Network’s distribution network where its standard load control signalling operates.⁵³

⁴⁸ QFF, sub 12, pp 5–6; Canegrowers, sub 1, p 6; Cotton Australia, sub 3, p 5.

⁴⁹ EEQ, sub 4, p 3.

⁵⁰ QFF, sub 12, p 6; Canegrowers, sub 1, p 6; Cotton Australia, sub 3, p 5.

⁵¹ QFF, sub 12, p 6; Canegrowers, sub 1, p 6.

⁵² Tariffs 62A, 65A and 66A are based on transitional network tariffs introduced by Ergon Energy Distribution in 2021–22, which replaced the earlier obsolete retail tariffs 62, 65 and 66 (first made obsolete in 2012–13). The transitional network tariffs are scheduled to expire on 1 July 2026.

⁵³ Other access requirements for these tariffs also apply, including these tariffs not being available to customers connected to the Essential Energy network within Queensland.

Stakeholder comments

Ergon Energy Network (EEN) and Energex proposed that the retail tariff schedule be amended to allow customers to access tariffs 60A and 60B in other areas as determined by EEN where standard load control signalling does not operate. EEN and Energex said this would better accommodate emerging technologies and allow more customers to access and benefit from these tariffs, noting some large customers (including agricultural customers) cannot access these tariffs due to standard load control signalling not operating in their area.⁵⁴

Draft decision

We appreciate the intention to make tariffs 60A and 60B available to more customers and note stakeholders have previously advocated for access to these tariffs in parts of the network where standard load control signalling is not operating.⁵⁵

However, the standard load control signalling requirement reflects a requirement in the approved network tariff arrangements.⁵⁶ In accordance with the N+R framework, network tariff requirements should be reflected in the retail tariffs we set. It is also unclear to us whether tariffs of this nature could be made available at the retail level in circumstances that are not provided for in the relevant network tariff arrangements.

We propose to amend the retail tariff schedule to allow tariffs 60A and 60B to be provided to customers in other circumstances as permitted by network tariff arrangements. This will mean that, if the network tariff arrangements are amended to permit other load control technology to be used, this change will be reflected in notified prices without the need for further amendment to the retail tariff schedule.

⁵⁴ EEN and Energex, sub 5, p 2.

⁵⁵ See, for example, QCA, [Supplementary review: Regulated retail electricity prices 2020-21](#), final determination, October 2020, p 13.

⁵⁶ EEN, [Tariff Structure Statement: Regulatory Determination Proposal 2025-26](#), November 2024, as amended and approved by the AER April 2025, pp 16 and 21; EEN, [Ergon Energy Network Tariff Guide: 01 July 2025 to 30 June 2026](#), July 2025, p 40.

4 Individual cost components

The notified prices consist of network costs (N component) – for transporting electricity transport via distribution and transmission networks – and retail costs (R component) – for buying and selling electricity to customers – along with other costs.⁵⁷

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

- setting the N component – based on network prices to be approved by the AER (in this report we are using draft prices provided by EEN and Energex)
- 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.⁵⁸

4.1 Network component

The N component includes costs for transporting electricity through transmission and distribution networks, as well as jurisdictional scheme charges⁵⁹ and the cost of legacy (accumulation) meters for small customers.⁶⁰ These 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 pricing approach we applied in previous determinations.

Stakeholders provided feedback on the structure and level of certain network-driven tariffs, particularly the balance between fixed, demand and volumetric components:

- Canegrowers said the price difference between tariff 34 and standard flat tariffs (such as tariff 20) has narrowed over time, weakening incentives for participation in controlled-load arrangements. It said that tariff 34 usage rates should be reduced to better reflect long-run marginal costs and to preserve customer participation and associated system benefits.⁶¹
- CPAQ noted that fixed and demand charges constitute 44–75% of electricity bills for caravan and residential parks, leaving only a small portion linked to actual consumption. It said that tariffs should be rebalanced toward volumetric charges to strengthen incentives for solar, batteries and energy-efficiency investment.⁶²

We recognise stakeholder concerns regarding tariff structures and the relative weight placed on fixed, demand and volumetric charges. However, network tariff design, including the balance of

⁵⁷ These other costs and related adjustments are discussed in chapter 5.

⁵⁸ For small customers, we also include the cost of advanced digital metering services in the R component, to reflect the ongoing rollout of these meters in regional Queensland (see section 4.2).

⁵⁹ In Queensland, these charges include the Solar Bonus Scheme and Australian Energy Market Commission levy costs.

⁶⁰ Since 2025–26, network prices approved by the AER include the costs of legacy (accumulation) meters. See AER, [Energex Electricity Distribution Determination 2025 to 2030: Overview](#), final decision, April 2025, p 31.

⁶¹ Canegrowers, sub 1, pp 6–7.

⁶² CPAQ, sub 2, pp 3–4.

costs between tariff components, or cost relativity between individual tariffs such as tariff 34, is determined through the AER’s regulatory processes, and not by the QCA. Our role in setting notified prices is to apply the network prices approved by the AER in accordance with the UTP and the N+R methodology.

We have used draft EEN and Energex network prices to set the N component in notified prices for this draft determination. We intend to use the AER-approved network prices in our final determination, subject to the availability and timing of this information.⁶³

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 (being the charges and tariff structures levied by Energex in SEQ)
All other existing retail tariffs	Relevant Energex network prices but utilising EEN’s tariff structures
Large customers	
	Relevant network prices for EEN’s east distribution pricing zone (being the Ergon Energy pricing region with the lowest cost of supply that is connected to the NEM)
New large customer solar soaker tariff (tariff 50C)	Based on the relevant network price for existing large customer tariff 50B (see section 3.1.1)

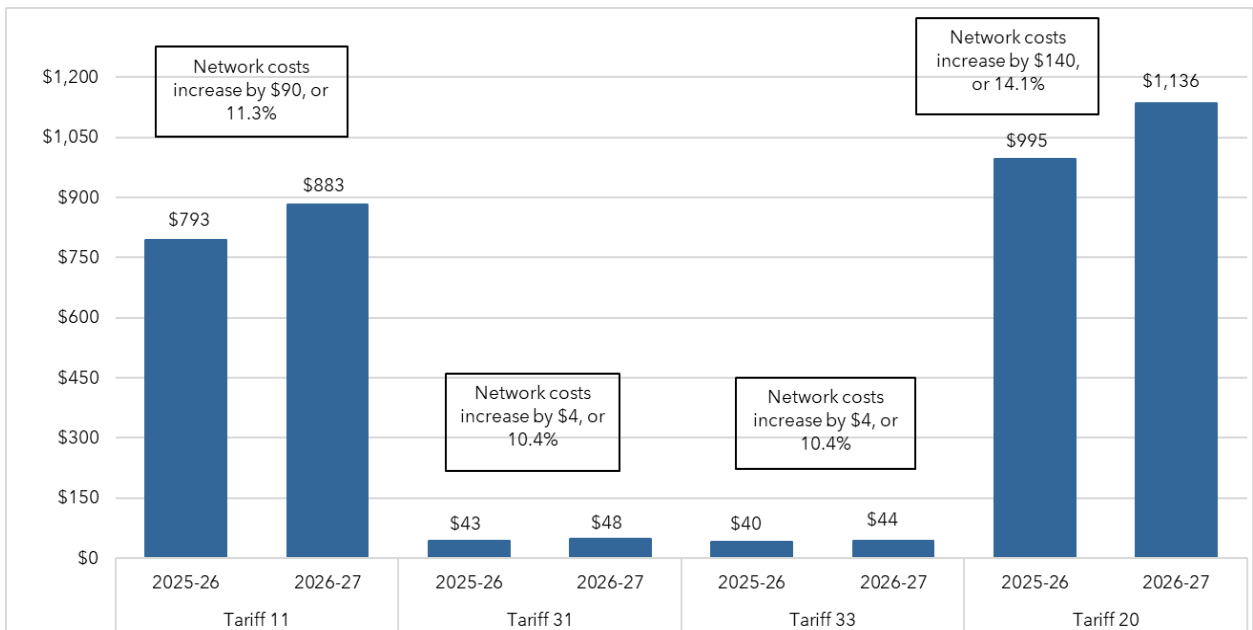
Network costs included in draft notified prices

Network costs have increased for small and large customers compared to last year. The change to the annual bill for a typical customer is shown in Figures 4.1 and 4.2.⁶⁴

⁶³ If the AER has not published approved network prices by the time we make our final determination, we will continue using the draft network prices. If AER-approved prices then differ from the draft prices, we will consider using a cost pass-through mechanism to adjust for material differences in the future if we are delegated this task.

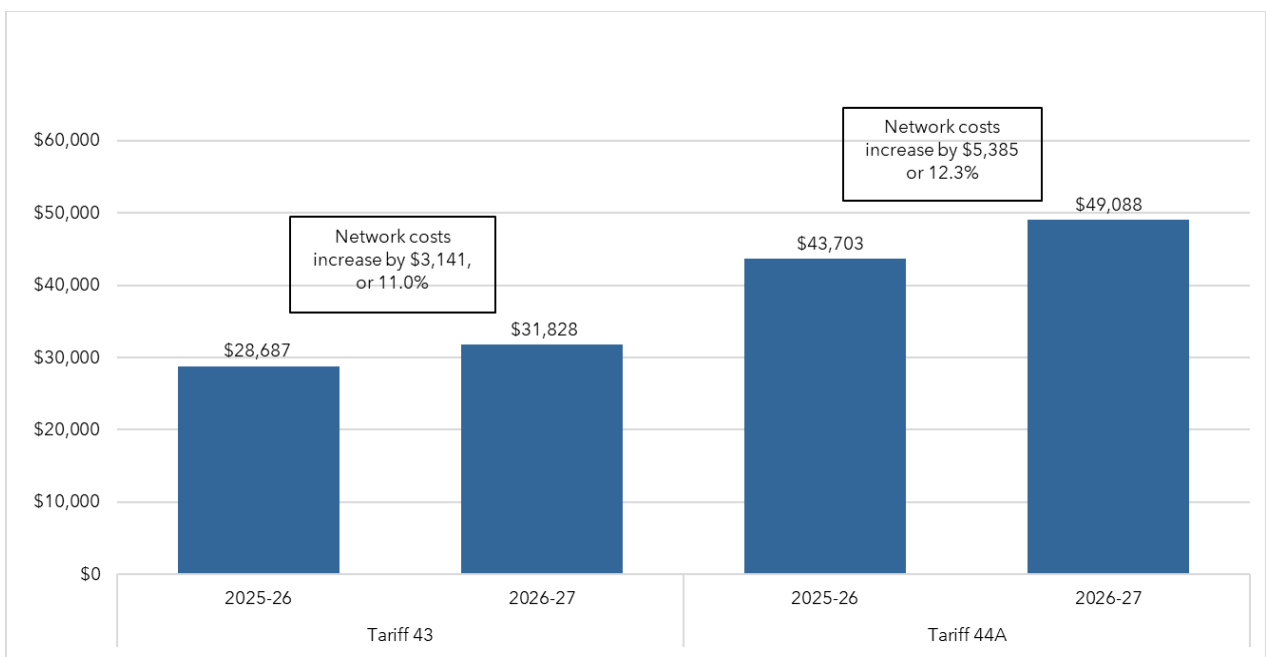
⁶⁴ Amounts presented are rounded. Percentage changes are based on unrounded amounts.

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



Note: Bill changes (dollar amounts) are rounded. Percentage changes are based on unrounded amounts.

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



Note: Bill changes (dollar amounts) are rounded. Percentage changes are based on unrounded amounts.

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-related services to customers.

4.2.1 Energy costs

Energy costs include wholesale energy costs (WEC) – the costs of purchasing electricity from the NEM – as well as other energy-related costs such as Renewable Energy Target obligations and energy losses.

This year, we engaged ACIL Allen (ACIL) to provide expert advice and estimate energy costs. The information we relied on from ACIL's draft report is available on our website and will be updated for the final determination.

Wholesale energy costs

The WEC reflects the costs retailers incur when purchasing electricity from the NEM to meet customer demand. Because spot prices in the NEM can fluctuate significantly, retailers typically manage this risk using hedging strategies such as financial contracts and operational methods.⁶⁵

Our WEC estimates are based on ACIL's advice that use:

- **a market hedging approach** – which estimates the WEC for a retailer that manages spot price risk by using ASX Energy futures contracts
- **the most up-to-date information** – including contract data up to 20 February 2026.

This approach is generally consistent with the methodology we used in previous years (see Box 5).

⁶⁵ Spot prices are settled every 5 minutes and currently can range from -\$1000 to \$20,300 per megawatt hour.

Box 5: Estimating the WEC

The estimated WEC for a given year is based on two key components:⁶⁶

- **wholesale energy spot prices** – which are simulated using assumptions about:
 - supply conditions in the NEM, such as power plant availability and renewable energy production
 - demand changes, based on weather data, historical demand, solar uptake and forecasts from the Australian Energy Market Operator (AEMO)
 - generator bidding behaviour and how it may change with market conditions and costs
- **retailers' hedging strategies and contract prices** – the WEC is estimated using a model that simulates an efficient retailer hedging its exposure to spot price risk by using publicly available ASX Energy contracts. Key inputs include:
 - trade-weighted average prices for quarterly base and cap contracts⁶⁷ using Queensland trade data up to 20 February 2026
 - contract trading that occurs several years before the delivery year (for example, trading for 2026–27 contracts began in mid- to late 2023), reflecting how retailers typically lock in costs early.

This model produces 605 annual hedged energy cost estimates. We adopt the 95th percentile from these estimates as our WEC to reduce the risk of understating the costs a prudent retailer could face in the NEM.⁶⁸

We consider this approach produces robust and transparent WEC estimates.⁶⁹ It uses a large number of simulations and incorporates the latest available market data.

Stakeholders raised several concerns about our approach for estimating the WEC.

QEUN's concerns centred on the reliance of a single consultant to estimate energy costs for both the QCA and the AER. It noted that energy costs account for around 40% of a typical small customer bill and that the estimates are produced using a proprietary model. QEUN said the modelling should be independently scrutinised to ensure there are no inaccuracies that could lead to overstated electricity prices.⁷⁰ It also noted that upcoming changes to the DMO framework and the introduction of the solar sharer offer may affect energy cost estimates and increase the importance of ensuring the estimates are robust and transparent.⁷¹

We acknowledge QEUN's comments on the importance of the energy cost estimates. While some elements of the model are proprietary, the key methodology, assumptions and cost drivers are

⁶⁶ This summarises ACIL's method used for estimating the WEC. See ACIL's draft report, pp 7–21.

⁶⁷ Consistent with past reviews, the trade-weighted contract price incorporates data on base contract call options.

⁶⁸ We adopt the 95th percentile because wholesale electricity prices in the NEM have greater potential to increase than to decrease.

⁶⁹ ASX Energy contract prices are publicly available. ACIL also found that WEC estimates from previous reviews were generally consistent with subsequent (actual) movements in the trade-weighted contract prices. See ACIL's draft report, pp 31–32.

⁷⁰ QEUN, sub 11, pp 1–3.

⁷¹ QEUN, sub 11, p 6.

published and subject to scrutiny. Substantive issues raised by stakeholders are tested with ACIL and incorporated where appropriate. If QEUN has specific concerns with elements of the methodology, we encourage it to identify these so they can be considered transparently.

EEQ said it continues to have concerns that the hedging strategy used to estimate the WEC does not reflect how retailers manage risk in practice. It noted the model relies heavily on flat swaps and cap contracts and does not utilise 'shaped' products, such as evening peak contracts, commonly traded in over-the-counter (OTC) markets.⁷²

While we acknowledge these concerns, the hedging strategy, including product mix, is not intended to replicate individual retailer behaviour in the market. Instead, it provides an objective and transparent estimate of wholesale costs based on publicly available ASX contract data. Retailers may use alternative hedging strategies or products that better match their risk exposure.⁷³ Where this occurs, retailers may achieve costs below the estimated WEC. We also set the WEC at the 95th percentile of modelled outcomes to account for the asymmetric risk of wholesale price increases.⁷⁴

Demand profiles

We typically use 2 to 3 years of historical demand data for our WEC estimates. This year, we used demand data from 1 October 2023 to 30 September 2025, adding an additional year of data relative to last year.⁷⁵ We also made one additional refinement to improve the quality of the data. This was to use interval meter data for the controlled loads obtained directly from EEQ.⁷⁶ This data gives us more accurate profiles for the controlled loads.⁷⁷

We continue to combine the net system load profile (NSLP)⁷⁸ with advanced digital meter (ADM) data when considering historical demand profiles. Using the interval meter data improves our estimate of the cost of supplying energy to small customers because, in combination with the NSLP, it better reflects the shape of the demand profile. Further, and consistent with our 2024-25 and 2025-26 reviews, the ADM data *includes* demand satisfied by solar PV exports, as the resulting profile reflects total demand that a retailer needs to supply to its customers (i.e. not total demand less solar exports).⁷⁹

EEQ said retailers hedge against net demand (i.e. total demand less demand met by solar exports) and argued that separating demand and export profiles may result in hedge positions that are overly long during the middle of the day and short during evening peaks. EEQ further noted the AER's view that retailers can manage their costs arising from solar exports through feed-in tariff adjustments, virtual power plants, or industrial load management. However, EEQ said that it cannot

⁷² EEQ, sub 4, pp 3-4. Evening peak contracts better align hedge coverage with the periods of higher wholesale price risk (i.e. typically 4 pm to 10 pm).

⁷³ Retailers may use alternative strategies such as OTC contracts and/or investing in own generating units.

⁷⁴ Wholesale prices in the NEM have greater scope to increase than decrease. This also reflects the risk that contract market conditions may change between the data cut-off date (20 February 2026) and the period covered by the determination (1 July 2026 to 30 June 2027).

⁷⁵ In the 2025-26 review, we were limited to one year of demand data because we excluded an artificial uplift in the Queensland NSLP between 1 October 2021 to 30 September 2023. This uplift arose from a temporary manual adjustment applied by AEMO. AEMO made the adjustment to address negative demand values associated with the introduction of 5-minute settlements. See ACIL's draft report, pp 15-16. As the adjustment was removed after 1 October 2023, it does not affect data used for this determination.

⁷⁶ The demand profiles correspond to the super economy (9000) CLP and economy (9000) CLP profiles.

⁷⁷ These datasets represent an improvement on AEMO's Market Settlement and Transfer Solutions (MSATS) data. The MSATS data involves only a sample of data from accumulation meter customers, while the EEQ data reflects a comprehensive set of interval meter data. The new data also enables us to remove controlled load volumes from the general interval meter data provided by AEMO.

⁷⁸ AEMO publishes NSLPs used to approximate the demand of customers on accumulation meters.

⁷⁹ See ACIL's draft report, pp 11-12.

use these options due to its current regulatory environment— as we set the regional feed-in tariff, EEQ cannot compete for industrial load due to the non-reversion policy, and it is unable to offer a virtual power plant due to regulatory restrictions.⁸⁰

Our view is that the relevant demand profile for notified prices is total demand (i.e. including demand satisfied by solar exports), as notified prices apply to all electricity consumed. While retailers may hedge against net demand, additional costs associated with solar exports can be reflected in the FiT. Accordingly, we consider these costs when we set the solar FiT for regional Queensland.⁸¹

Outcomes and key drivers

WECs generally decreased compared to last year. For:

- **small customer primary tariffs** – the WEC decreased by 10.6%
- **small customer load control tariffs** – the WEC decreased by 2.5% and 8.5% for tariffs 31 and 33 respectively
- **large customer tariffs** – the WEC decreased by 7.8%.⁸²

These reductions are primarily driven by lower wholesale electricity spot prices in 2025, reflecting higher availability of Queensland coal generators, lower gas prices and continued uptake of battery energy storage systems (BESS) and renewable generation. Together, these factors reduced both the level and volatility of wholesale spot prices:⁸³

- **For small and large customer primary tariffs (tariffs 11, 20, 43, 44A)** – demand profiles have again flattened slightly relative to last year. The largest reductions occur for tariffs 11 and 20, whose demand profiles have been most affected by changes in demand shape associated with increasing renewable energy generation and battery uptake.⁸⁴
- **For small customer load control tariffs (tariffs 31 and 33)** – the decrease in WEC is greater for tariff 33. This is because tariff 33 demand is more concentrated in the evening peak period and therefore it benefits more from the reduction in evening prices and price volatility.^{85,86}

Time-varying wholesale energy costs (small and large customer tariffs)

For TOU tariffs 12E, 22E and the new large customer tariff 50C, we use time-varying WEC estimates to create stronger differences between peak and non-peak periods, compared to tariffs 12D, 22D and 50B, on which these tariffs are based.⁸⁷

Consistent with previous determinations, the time-varying WECs are based on ACIL's advice and are derived by:

⁸⁰ EEQ, sub 4, pp 4-5.

⁸¹ See QCA, *Solar feed-in tariff for regional Queensland 2026-27*, draft determination.

⁸² The WEC for very large customers (i.e. connection asset customers (CAC) and individually calculated customers (ICC)) decreased by 1.6%.

⁸³ A substantial amount of utility scale BESS capacity is expected to come on-line over the next 12 months, contributing to lower contract prices in 2026-27, compared with 2025-26.

⁸⁴ Our recent determinations have noted that the continued uptake of rooftop solar and utility-scale solar generation reduces daytime demand. However, in the context of this review, load profiles have begun to stabilise due to strong uptake of behind-the-meter BESS, which is largely offsetting the continued growth in solar PV.

⁸⁵ The reduced volatility also reflects the expected increase in utility-scale BESS capacity in 2026-27.

⁸⁶ The change in data sources for the controlled loads does not materially affect the WEC, as the demand profile shapes are similar across both datasets.

⁸⁷ The basis for this approach is set out in the [2023-24 final determination](#), sections 3.2.1 and 4.2.1. As tariff 22C was made obsolete in our 2025-26 determination, the time-varying WEC is now applied to tariff 22E.

- using the WEC estimates for tariffs 12D, 22D and 50B
- calculating weightings for different times of the day based on demand-weighted wholesale spot price variations, where non-peak periods (daytime) generally have lower prices, while peak periods (evening) have higher prices.
- applying these weightings to allocate lower costs to non-peak periods (typically daytime) and higher costs to peak periods (typically evening).

The time periods align with network tariff structures approved by the AER.

This method maintains the same total WEC as the underlying tariffs (12D, 22D and 50B) but redistributes costs across time periods to strengthen price signals.⁸⁸ Table 4.2 sets out the time-varying WEC estimates included in draft notified prices this year.

Table 4.2: Time-varying WECs for tariffs 12E, 22E and 50C

Period	Tariff 12E ^a c/kWh	Tariff 22E ^b c/kWh	Tariff 50C ^c c/kWh
Peak (evening)	19.33	20.97	18.03
Non-peak (day)	4.29	4.14	3.24
Shoulder (night)	14.37	13.47	10.52

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 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.

c For tariff 50C, 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 several other energy costs when buying electricity from the NEM. These include costs associated with renewable energy obligations, market operation fees, ancillary services, prudential requirements and energy losses.

We estimate these costs based on ACIL's advice, which draws on publicly available and reliable data sources to reflect the costs retailers are likely to face.⁸⁹ Table 4.3 summarises these costs and the approach used to estimate them.

⁸⁸ Time-varying WECs for tariffs 12E and 22E are based on the Energex residential and small business WEC, while the time-varying WEC for tariff 50C is based on the Ergon Energy Standard Asset Customer (SAC) demand WEC (i.e. SAC large).

⁸⁹ See ACIL's draft report, pp 25-33, 52-61.

Table 4.3: Other energy costs – description and estimation approach

Costs	Description	Approach to estimation
Renewable energy target (RET) costs	Costs of buying certificates to meet the Large-scale Renewable Energy Target (LRET) and the Small-scale Renewable Energy Scheme (SRES) ⁹⁰	LRET costs – use forward prices for large-scale generation certificates (LGC) and renewable power percentage (RPP), based on mandated targets and estimates of electricity acquisitions.
		SRES costs – use the clearing house price for small-scale technology certificates (STC) and the small-scale technology percentage (STP).
NEM fees	Fees paid to AEMO for operating the NEM	Use AEMO’s latest budget report, which includes fixed and variable fees. ⁹¹ The 2025–26 budget is used for the draft determination and will be updated if the 2026–27 report is available before the final determination. ⁹²
Ancillary services	The costs of services used by AEMO to maintain power system safety, security and reliability	Use the average historical costs over the past 52 weeks, published by AEMO.
Prudential costs	The costs of providing financial guarantees to AEMO and to lodge initial margins with the ASX for futures contracts	Use AEMO’s prudential requirements and ASX margin requirements for futures trading.
Energy losses	The cost of additional electricity retailers must purchase to account for transmission and distribution losses when electricity is transported across the network ⁹³	Use AEMO’s published transmission and distribution loss factors. We used 2025–26 data and will update this if new information is available before the final determination. ⁹⁴

⁹⁰ LRET and SRES schemes encourage renewable energy generation and reduce greenhouse gas emissions. Retailers meet these obligations by purchasing LGCs and STCs created when eligible renewable electricity is generated.

⁹¹ See ACIL’s draft report, p 25. The fixed NEM fee is recovered in the daily supply charge as a fixed energy cost component. This change was implemented last year following changes to AEMO’s NEM fee structure.

⁹² AEMO’s 2026–27 draft budget report is expected to be published in April 2026.

⁹³ Energy losses are applied to the combined value of the WEC and other energy costs to determine the total loss-related cost.

⁹⁴ AEMO’s 2026–27 loss factors are expected to be published in April 2026.

Stakeholders raised several issues regarding our estimates of other energy costs. We have considered the matters raised but have not changed our approach or estimates for this determination:

- LGC allowance – EEQ said the methodology should incorporate a broader range of broker prices to reflect industry practice and improve robustness. We consider existing sources provide sufficiently robust estimates, as prices across brokers are generally closely aligned, and adding other brokers’ estimates would not materially affect/improve our estimate (and it would increase complexity and costs).
- NEM fees – EEQ noted that AEMO’s NEM fee structure is expected to change from 1 July 2026. We will assess any change and update the estimate if new information becomes available before the final determination.

Other energy costs⁹⁵ have decreased compared to last year:

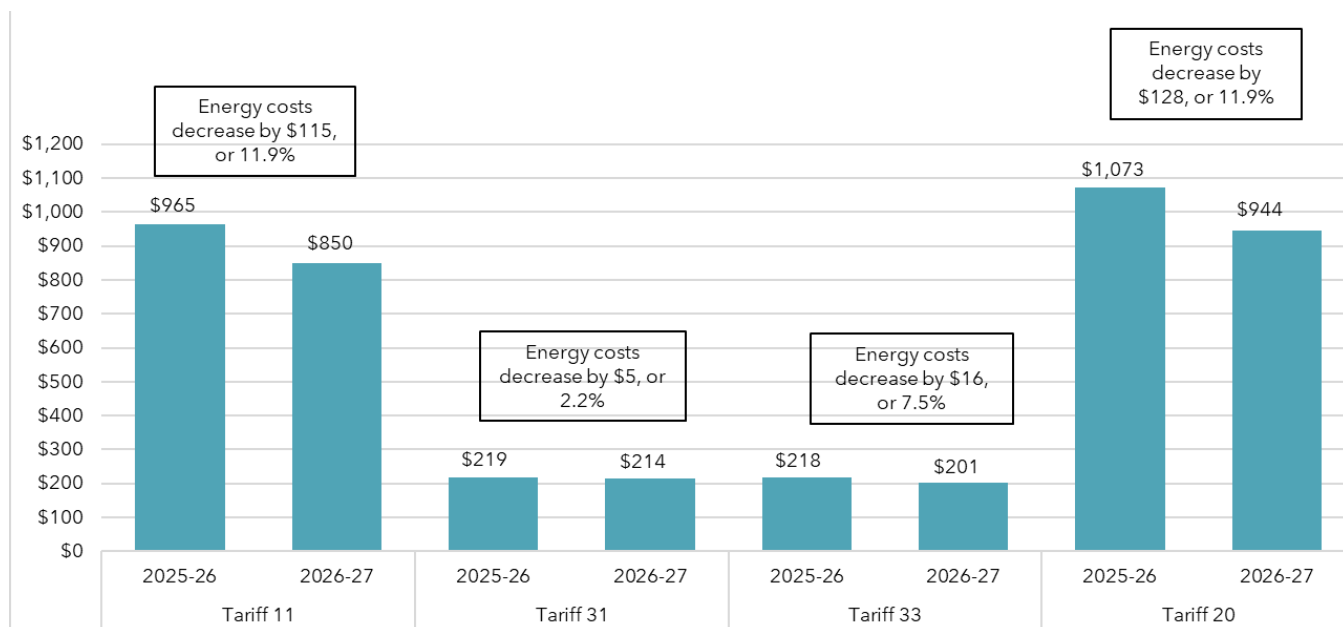
- for small customer tariffs – by 26.6% (\$4.21/MWh)
- for large customer tariffs – by 26.0% (\$3.81/MWh).

The reasons for these changes are explained in ACIL’s report.⁹⁶ We will update these estimates for the final determination if new information becomes available.

Total energy costs included in draft notified prices

Overall, total energy costs are estimated to decrease for customers. Figures 4.3 and 4.4 compare the total energy costs included in draft notified prices with last year’s estimates, by tariff and customer type.

Figure 4.3: Draft energy costs – small customer tariffs (incl GST)

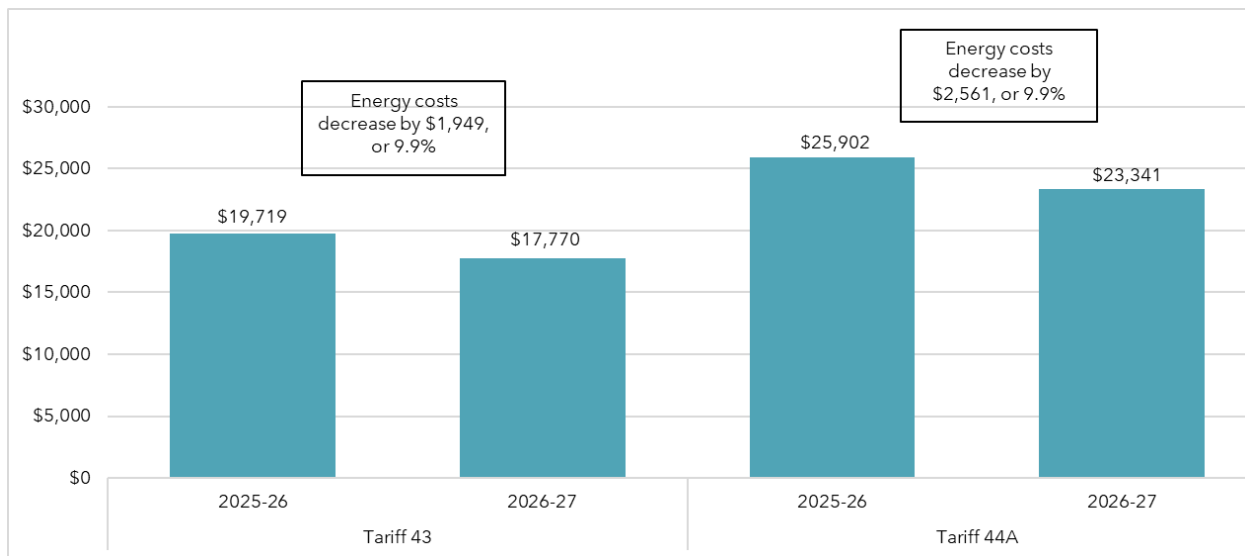


Note: Bill changes (dollar amounts) are rounded. Percentage changes are based on unrounded amounts.

⁹⁵ This excludes costs associated with energy losses and the fixed NEM fee.

⁹⁶ The changes to each cost category are set out in ACIL’s draft report, pp 55, 61.

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



Note: Bill changes (dollar amounts) are rounded. Percentage changes are based on unrounded amounts.

4.2.2 Retail costs – small customers

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.

To date, we have determined retail cost allowances using a well-established benchmarking methodology that estimates the costs an efficient retailer would incur, based on market data.⁹⁷

We review the benchmark allowances periodically to ensure they remain appropriate and reflect costs associated with current retail operating conditions. The most recent review occurred as part of the 2021–22 notified prices determination.

Several stakeholders said it was timely to revisit retail costs, noting the length of time since the last update and the potential for changes in operating conditions since then:⁹⁸

- The Queensland Consumers' Association said that increased electronic billing, payment and customer contact should have reduced retail costs.
- EEQ said retail costs are increasing faster than CPI and that CPI indexation is no longer adequate, noting that ACCC data shows residential retail and other costs increased by 25.3% between 2021–22 and 2023–24.⁹⁹

Stakeholders had different views on the approach for updating the retail costs:

⁹⁷ The benchmark retail cost allowances were first established in 2016–17, and then reviewed as part of our [2021–22 notified price review](#) – when the allowances for small customers were updated (based on market information) and the allowances for large customers were reviewed but ultimately retained.

⁹⁸ Queensland Consumers' Association, sub 9, p 1; QCOSS, sub 10, p 5.

⁹⁹ EEQ, sub 4, p 7.

- Some stakeholders said we should undertake a bottom-up assessment of retail costs¹⁰⁰, and QCOSS said retail costs should then be set at the lower of the existing benchmark (rolled forward) or the newly established bottom-up estimate.¹⁰¹
- EEQ said it does not support using SEQ market offers to update the retail costs because:
 - market offers typically reflect customers trading away the higher cost services provided under a standard retail contract in exchange for lower prices
 - notified prices apply to standard retail contract customers, and it is not appropriate for the retail costs to be derived from market contract cost structures.¹⁰²

In addition, EEQ said there is a need for greater transparency around the cost components included in the retail cost allowance so that customers understand how their choices contribute to retailer costs, e.g. the impact of rapidly increasing Australia Post charges, when e-billing is readily available.¹⁰³

Draft decision

We tested whether the retail cost benchmark should be updated using recent SEQ market data. However, given the volatility of the benchmarking results, the SEQ retail market environment, and the limited value of alternative approaches within the current review timeframe, we have decided to retain the existing benchmark for 2026-27.

Benchmarking results

We engaged ACIL to apply the established benchmarking methodology to recent 2025-26 SEQ market offers.¹⁰⁴

Under this method, retail costs are derived as a residual – that is, after subtracting the following from observed market offer prices:

- regulated wholesale energy costs,
- regulated network costs, and
- regulated retail-related metering costs.

In principle, this approach should capture changes in underlying cost structures over time, including both cost increases and productivity improvements such as those mentioned by stakeholders.

Applying the methodology to 2025-26 market data produced materially different results to the current benchmark. In particular:

- the fixed retail costs declined significantly:
 - for small business, from around \$214 per customer per year (2021-22 benchmark, expressed in current dollars) to around \$47
 - for residential customers, from around \$153 to around \$63
- there were significant shifts between fixed and variable components and wide variation across retailers. In some cases, the implied retail cost was negative.¹⁰⁵

¹⁰⁰ QCOSS, sub 10, p. 5, Queensland Consumers' Association, sub 9, p 1.

¹⁰¹ QCOSS, sub 10, Etrog report, pp 5-6.

¹⁰² EEQ, sub 4, p 7.

¹⁰³ EEQ, sub 4, p 7.

¹⁰⁴ ACIL's report is available on our website.

¹⁰⁵ ACIL's draft report, p. 18.

As retail costs are derived as the residual from observed SEQ market offers, the results are sensitive to cost inputs used in the calculation. For example, regulated metering allowances and wholesale energy costs may differ from the costs faced by individual retailers in SEQ. More broadly, if competitive market offers recover costs differently to our regulatory cost estimates – for example, through different allocations between fixed and variable components – this can materially affect the residual retail cost estimates.

Differences in regulated and actual metering cost estimates, including how these costs are recovered in the DMO compared to market offers may explain part of the movement in fixed retail costs. However, the material reduction in small business retail costs persists even when metering is excluded, indicating that metering inputs alone do not explain the observed outcomes.

Additionally, retail operating costs are typically incurred on a per-customer basis and do not vary significantly with energy usage. As a result, retail cost structures are generally expected to be predominantly fixed, meaning that large reductions in fixed costs are not consistent with the way retail costs are typically incurred and recovered by retailers.

Given the way retail costs are derived, it is not possible to provide the level of transparency EEO sought to help customers understand how their choices affect retailer costs, such as paper billing. To the extent that cost drivers differ for EEO compared to those observed in SEQ, these matters are more appropriately addressed through the retailer's own operational practices.

SEQ market environment and reforms

The benchmarking approach works best where market prices reflect a reasonably consistent recovery of underlying costs. Current market conditions in SEQ suggest this may not be the case.

ACCC analysis shows that pricing in SEQ varies significantly depending on the age of the plan. In SEQ:

- customers on plans more than three years old pay around 10% (about \$213 per year) more than customers on plans less than one year old for similar flat rate offers.¹⁰⁶
- residential customers were quoted average potential savings of around \$616 per year, and small business customers around \$320 per year, in better-offer messages.¹⁰⁷

This indicates that retailers maintain materially different price levels within their customer portfolios.

ACCC data also shows that acquisition-style offers in SEQ tend to move closely with the DMO and are typically positioned below the DMO cap. This suggests that competitive pricing may be influenced by positioning relative to the DMO cap.

In this environment, newer competitive offers – which form the basis of benchmarking – may reflect customer acquisition strategies and portfolio segmentation, rather than a consistent recovery of efficient retail operating costs across all customers.

Relevantly, there are significant reforms underway expected to broadly impact pricing dynamics across the NEM and in SEQ. From 1 July 2026, new rule changes are expected to reduce loyalty penalties and narrow the spread of prices across customers. These include:

- preventing customers coming off fixed-term contracts from being charged more than the standing offer price¹⁰⁸

¹⁰⁶ ACCC, *Inquiry into the National Electricity Market*, final report, December 2025, p 32 (Figure 3.8).

¹⁰⁷ ACCC, *Inquiry into the National Electricity Market*, final report, December 2025, Table 3.3.

¹⁰⁸ AEMC, *Improving consumer confidence in retail energy plans*, rule determination, June 2025.

- removing certain conditional discount structures on older plans¹⁰⁹ and
- the broader DMO reforms impacting pricing in SEQ (see section 5.1 for information on the DMO reforms and impacts for our review).

Overall, these reforms are designed to reduce the prevalence of higher-priced legacy plans and move more customers onto lower-priced offers.

Given these changes, current market pricing patterns may not reflect how retailers will recover their costs and the market offers available in SEQ during 2026–27, once the reforms take effect.

Option assessment

Updating the benchmark would align allowances with recent SEQ market offers. However, given the significant volatility observed, the sensitivity of the residual methodology, and evidence of material price variances in SEQ, we consider that updating the benchmark this year could risk embedding short-term pricing dynamics into notified prices.

Several stakeholders suggested that we independently estimate retail costs using a bottom-up approach. We do not consider this appropriate in the current review for three reasons:

- The AER undertakes a comprehensive assessment of retail costs as part of its DMO determination, drawing on detailed data obtained from retailers and other market participants using its information gathering powers. Replicating this exercise would duplicate an existing regulatory process. It would also be challenging for us to undertake a comparable review given we do not have equivalent information-gathering powers to obtain detailed retailer cost data. Undertaking a comparable process would therefore impose additional administrative burden on the QCA and retailers, without improving regulatory outcomes.
- The timing of the DMO decision relative to our draft determination means it is not practicable to undertake a comparable bottom-up review or to adopt the AER’s retail cost estimates within this review cycle.
- Notified prices in regional Queensland are capped at the DMO. This means that even if our cost build-up would otherwise result in higher prices, the DMO operates as a binding constraint (see section 5.1).

Draft decision

On balance, we consider the summary of benchmarking results previously presented suggests either a fundamental change in pricing dynamics or sensitivities of the benchmarking methodology. Therefore, we do not consider placing reliance on the outcomes from the 2025–26 data to be appropriate.

We consider a more prudent approach under these circumstances is to retain the existing retail cost benchmarks for 2026–27. Informing this view is that rule changes and reform activities underway – especially the DMO reforms – are likely to have implications for retailer behaviour in the market and affect market offers during this time.

However, we will reassess this approach in future reviews, including once the recent rule changes have taken effect and their impact on market pricing can be observed.

Table 4.4 sets out the basis for determining retail cost allowances this year for small customers.

Table 4.4: Basis for determining retail cost allowances for small customers

¹⁰⁹ AEMC, [Improving consumer confidence in retail energy plans](#), rule determination, June 2025.

Customer type	Basis
Small customers	<p>Apply established benchmark costs (based on the costs of supply in SEQ) by:</p> <ul style="list-style-type: none"> • 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: <ul style="list-style-type: none"> – 7.25% for residential customers – 18.70% for small business customers.

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 2.9% for the financial year ending June 2027. See RBA, [Statement on Monetary Policy](#), February 2026.

Advanced digital metering 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.

ADM costs

We have set retail metering service costs for ADMs using a similar approach to last year's notified price review. Specifically, we apply the average cost incurred per ADM in SEQ to the forecast deployment of smart meters in the Ergon distribution region. This approach ensures customers in regional Queensland pay no more than customers in SEQ for metering services, consistent with the UTP.¹¹⁰

EEQ said it supports this approach but noted it relies on the AER's method being accurate. EEQ considers that the AER calculates average ADM costs by dividing total annual metering expenditure by end-of-period deployment numbers, which increases the denominator and lowers the per-meter allowance. EEQ said this results in under-recovery of metering costs (which occurred in 2025-26) and that using midpoint deployment numbers would provide a more accurate allowance. EEQ said we should set our own ADM allowance rather than directly adopting the AER's cost, then any requirement to maintain price equivalence with the DMO can be addressed through the DMO adjustment mechanism.¹¹¹

We acknowledge EEQ's concern. However, the AER's previously published ADM cost-per-meter figures (used in earlier determinations) were based on retailer-level unit-cost data collected directly from each retailer. These unit costs were not calculated using end-of-period deployment numbers as inputs.

Further, the AER has updated its approach for DMO 8 under its retail cost information notice. Under the updated method, the AER:

- collects retailers' absolute dollar costs by category (including smart meters) and their average customer numbers over the reporting period

¹¹⁰ We note, consistent with last year, the costs of ADMs are the only costs captured here, with costs for standard (accumulation) meters included in network prices since 1 July 2025. See AER, [Energex Electricity Distribution Determination 2025 to 2030: Overview](#), final decision, April 2025, p 31.

¹¹¹ EEQ, sub 4, p 6.

- calculates unit costs by dividing total smart-meter costs by average customer numbers.¹¹²

Under this updated method, end-of-period deployment figures are not used in the calculation of unit costs and should not impact the per-meter allowance as EEQ suggested.

We consider it appropriate to rely on the AER's published unit-cost data, which is based on retailer cost information and average customer numbers. There is no evidence before us that this is inaccurate.

Replicating this exercise would duplicate an existing regulatory process and impose unnecessary burden on retailers. It would also be unlikely to produce more robust outcomes, given our information-gathering powers are more limited than those of the AER.

True-up mechanism

We include a true-up mechanism for metering costs to reconcile any over- or under- recovery of metering costs from the previous year.

This process involves:

- comparing 2025–26 retail metering service costs, based on actual ADM deployment, to the allowance in current notified prices, which is based on forecast ADM deployment¹¹³
- taking the under- or over-recovery of metering costs (identified in step 1), and adjusting it for timing differences, to determine the pass-through amount for 2026–27 notified prices.

Based on our assessment, we estimated an over-recovery of retail metering service costs in 2025–26. This occurred due to a lower ADM deployment rate of 69.20 %¹¹⁴, compared to the forecast rate of 70.55%. After adjusting for timing differences, this results in an over-recovery of 0.355 c/day to be passed through to notified prices (subtracted from metering costs) in 2026–27.

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: Draft ADM costs for small customer tariffs, 2026-27 (excl GST)

Description	Metering costs (c/day)	Approach
Primary tariff	24.356	To calculate the base metering cost, we used: <ul style="list-style-type: none"> relevant ADM metering costs to apply in SEQ, published by the AER^a the forecast deployment rate of ADMs for small customers in regional Queensland for 2026–27, as provided by EEQ.
True-up adjustment	-0.355	To estimate the over- recovery of metering costs we: <ul style="list-style-type: none"> calculated the difference between the retail metering service costs based on a forecast ADM deployment (70.55%) compared to actual ADM deployment (69.20%)

¹¹² Australian Energy Regulator, *Default Market Offer 2026-27*, draft determination, March 2026, p 82, 83, 131.

¹¹³ As the costs are based on mid-year deployment forecasts, we use the actual deployment (as at December 2025) to calculate the actual metering costs used in this comparison. A lower actual mid-year deployment rate means less smart metering costs should have been included in 2025–26 notified prices.

¹¹⁴ Deployment rates are used in conjunction with the SEQ average cost incurred per smart meter to determine ADM costs for regional customers.

Description	Metering costs (c/day)	Approach
		<ul style="list-style-type: none"> adjusted the difference (over-recovery) in costs for timing differences (by applying the 9.20% weighted average cost of capital).
Overall charge	24.001	Based on the retail metering service costs, with the true-up amount added.

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](#), draft determination, March 2026.

We intend to use updated ADM cost information in our final determination.

Retail charge for manually reading a type 4A meter

There are costs associated with manually reading meters where a customer has chosen to disable the remote communication function of their ADM.

We have been asked to consider setting a series of retail charges based on EEQ's averaged 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.

EEQ said that the costs of type 4A meters are rising due to a small and dispersed fleet requiring manual reads. Ergon proposed the introduction of a of \$0.72/day for customers who disable meter communications, noting that customers can avoid the charge by re-enabling communications.

At this time, we consider using the AER-approved special meter read fee for Ergon Energy remains appropriate, pending further information from EEQ to support its proposed rate.¹¹⁵ In the absence of this information, we are not able to assess whether the proposed rate is reasonable, as compared to our current benchmark rate.

Given the AER is expected to approve the 2026–27 special meter read fee for Ergon Energy in May 2026, we have used the rate currently included in notified prices of \$49.86¹¹⁶ for the draft determination. This will be updated to reflect the approved fee in the final determination.

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

4.2.3 Retail costs – large customers

We periodically review the benchmark retail cost allowances for large business customers to ensure they remain appropriate and reflect current retail operating conditions. The most recent review occurred as part of the 2021–22 notified prices determination, at which time the existing benchmark was retained.

As part of this review, we considered whether new allowances should be established for large and very large business customers. However, due to the data quality issues identified below, we have maintained our existing approach – that is, we have set the retail cost allowances using the established benchmark adjusted for inflation.

¹¹⁵ Ergon Retail has previously advised that information on costs by feeder type is not available.

¹¹⁶ Ergon Energy Queensland, [2025–26 network price list](#), May 2025, accessed 2 February 2026.

Benchmarking results

We engaged ACIL Allen to review the existing benchmark using information obtained from retailers operating in the Ergon Distribution region. This included information on the retail costs incurred in supplying large and very large customers during 2025–26. Further information on the data and ACIL Allen’s approach is provided in its draft report published with this determination.

We received confidential data from 12 retailers – 9 relating to large customers and 7 relating to very large customers. While this represents a higher response rate than in previous reviews, reported retail costs varied significantly across retailers and 2 outliers in each category were excluded from the analysis.

Retailers also reported costs using different structures, some identifying fixed and variable components, others reported only one component or were unable to clearly separate cost drivers. In terms of expected cost movements, 5 retailers indicated their costs are likely to remain broadly unchanged between 2025–26 and 2026–27 (with one suggesting costs may be slightly lower), while 3 retailers expect costs to increase over this period.

ACIL noted that there is some subjectivity in the reported data, as retailers do not necessarily collect cost information in the form requested. The retail cost allowances approved in our 2025–26 determination fall within the range of estimates provided, although towards the upper end. On this basis, ACIL Allen considers that the existing benchmark retail cost allowances could reasonably be maintained in nominal terms until the next review.

Draft decision

On balance, we consider there is insufficient evidence to suggest that the retail cost allowances for large and very large business customers in 2026–27 will be materially different from those allowed in 2025–26.

While we have obtained more data than in previous reviews, the variability in reported costs and differences in cost structures mean the benchmarking results do not provide a sufficiently robust basis to replace the existing benchmark.

Table 4.6 sets out the basis for determining retail cost allowances this year.

Table 4.6: Basis for determining retail cost allowances for large customers

Customer type	Basis
Large customers	Apply established benchmark costs (based on the costs of supplying large customers) by: <ul style="list-style-type: none">adjusting last year's fixed retail costs^a for inflation^b to maintain fixed costs in real termsmaintaining the variable retail cost allocators at 6.0445%.

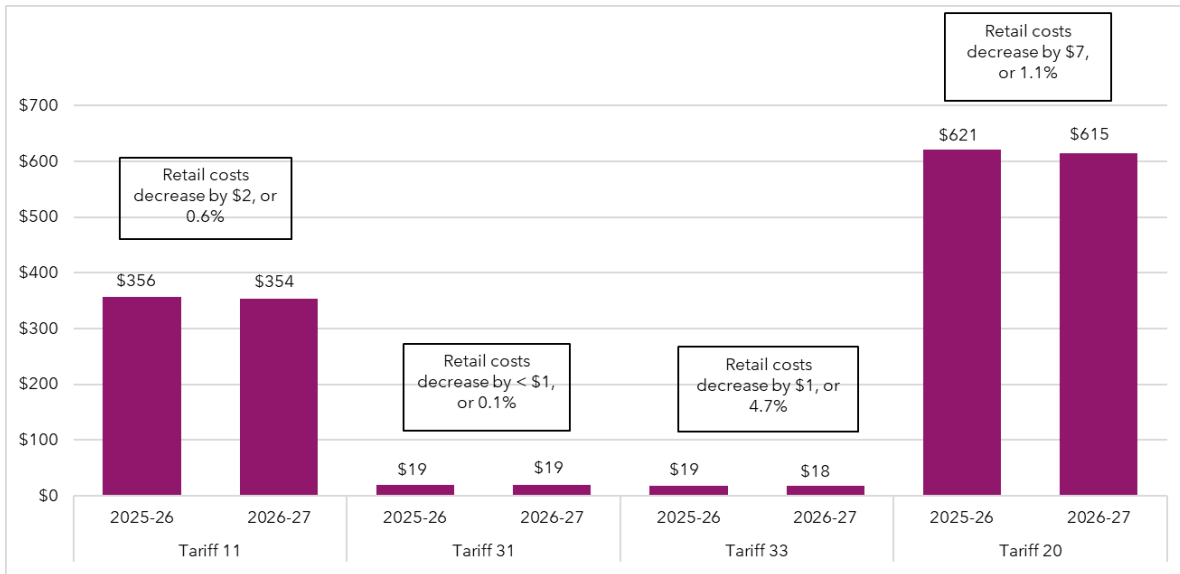
^a Fixed retail costs were set in our [2021–22 notified price review](#) and have been adjusted for inflation each year since. ^b We use the RBA's CPI forecast of 2.9% for the financial year ending June 2027. See RBA, [Statement on Monetary Policy](#), February 2026.

Retail costs included in draft notified prices

Overall, retail costs have not changed substantially (in dollar terms) compared to 2025–26, with most small customers experiencing slight decreases and most large customers facing small

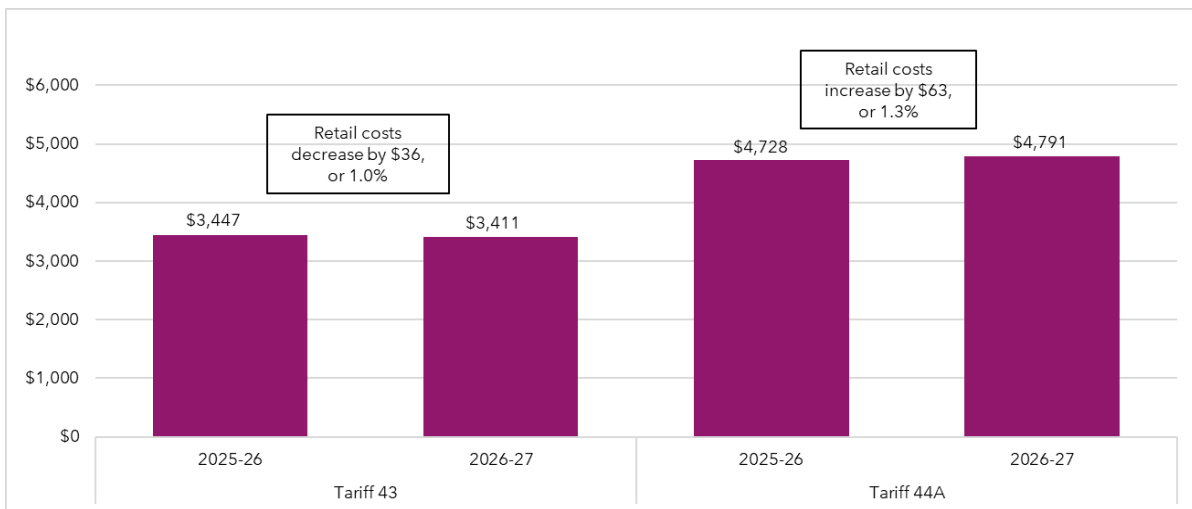
increases.¹¹⁷ The change to the annual bill for a typical small and large customer is set out in Figures 4.5 and 4.6.

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



Note: Bill changes (dollar amounts) are rounded. Percentage changes are based on unrounded amounts.

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



Note: Bill changes (dollar amounts) are rounded. Percentage changes are based on unrounded amounts.

¹¹⁷ Fixed retail costs increase (due to inflation) for all customers. Variable retail costs are calculated as a percentage of total (variable) network and energy costs, so changes in these components also affect retail costs. For tariff 43 customers, both (variable) network and energy costs decrease relative to 2025-26, reducing its variable retail costs sufficiently to decrease overall retail 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 to reflect the value of more favourable terms and conditions in standard contracts, relative to market contracts.

We estimate the SOA using an established method that draws on SEQ retail market information to assess the costs associated with market contracts (e.g. the fees and charges a typical SEQ customer may incur).¹¹⁸ This market data acts as a proxy for estimating the value of standard contract terms for customers in regional Queensland, specifically, the fees and charges they can avoid under these arrangements.

Using 2024–25 SEQ market data¹¹⁹ we:

- assessed the range of fees and charges included in SEQ retail market contracts
- identified additional fees that apply under retail market contracts but not standard contracts
- estimated the average additional costs that small customers in SEQ may incur when on market contracts.¹²⁰

Stakeholder comments

QCROSS said the SOA should be removed because it lacks transparency and available customer evidence does not support the view that standard contracts provide additional value relative to market contracts. It also said that the delegation indicates the SOA should operate only as a mechanism to support the DMO adjustment, and that there is no merit or delegation basis for retaining the SOA for any other purpose.¹²¹

Draft decision

While the delegation does not explicitly refer to the SOA, this does not preclude us from including it as part of the notified prices methodology. The SOA has been a longstanding component of the notified prices methodology and reflects the value of the more favourable terms and conditions available under standard retail contracts, relative to market contracts. This is relevant because

¹¹⁸ The method we use was established as part of the [2021-22 notified prices review](#).

¹¹⁹ This data reflects our most recent review of retail fees in SEQ (QCA, [SEQ retail electricity market monitoring 2024-25](#), December 2025, pp 38-54).

¹²⁰ The typical annual bill for small customers is based on June 2025 data from Appendix A of the QCA's [SEQ retail electricity market monitoring report 2024-25: Appendices](#).

¹²¹ QCROSS, sub 10, Etrog report, p 10.

elements of the notified prices methodology draw on market information from SEQ, where customers are typically supplied under market contracts (compared to customers on notified prices in regional Queensland who are supplied under standard contracts).

Importantly, the SOA does not attempt to measure the value customers themselves place on standard contract terms and conditions, which may vary across customers and may in some cases be zero. Instead, it reflects the value retailers place on these terms, as evidenced by the fees and charges applied under market contracts when customers do not comply with certain contract conditions. These fees provide observable market evidence of the cost retailers associate with removing or relaxing these conditions. As such, it is appropriate to recognise the additional value of the more favourable and certain terms and conditions available under standard retail contracts.

Based on our assessment of 2024–25 market data, small customers on market contracts in SEQ can incur additional fees of, on average, \$54.18 per year, equivalent to around 3.09% of a typical small customer’s annual bill.

Accordingly, we consider a SOA of 3.09% (of total costs) to be appropriate for inclusion in small customer notified prices. The SOA has decreased slightly from 3.35% in the previous determination.

The SOA is incorporated into notified prices before we do the DMO comparison (discussed below). The DMO adjustment is a separate step in our methodology to ensure notified prices comply with the requirements of the UTP and the delegation.

5.1.1 DMO comparison

The AER sets a DMO for standing offers in particular jurisdictions, including SEQ. The regulatory framework for the DMO has recently been reformed by the Australian Government, which will result in changes to the way in which the AER sets the DMO. Key elements of the DMO reforms are summarised in Box 6.

The delegation requires us to treat the SEQ DMO as a cap, with standard flat rate tariffs in regional Queensland to be set no higher than the equivalent SEQ DMO. It also states that a negative SOA may be applied if necessary to deliver on the Queensland Government’s UTP. When applying any SOA adjustment, tariff relativity for more complex small customer tariffs must be maintained.

This year, the Minister has also flagged the reforms and potential for changes to the DMO that could allow the DMO comparison to be based on tariff rates (i.e. the usage charge and fixed daily supply charge), rather than based on a reference bill as has been done in the past. However, the Minister has indicated a preference for maintaining the existing approach to the DMO comparison but asked us to consult with stakeholders on the merits of each approach.

Box 6: Summary of DMO and recent reforms

- **DMO introduced (2019):** The Australian Government introduced the DMO as a safety-net price cap for standing offers for residential and small business customers in New South Wales, South Australia and SEQ, and as a reference price to help customers compare market offers.
- **Current role:** The DMO is set annually by the AER and represents the maximum price retailers can charge customers on standing offers in these regions.
- **DMO reforms announced (2025):** The Australian Government announced reforms to the DMO with the objective of strengthening consumer protections and ensuring the price cap reflects the efficient cost of supplying electricity:
 - **Efficient cost focus** – the DMO will be more explicitly based on the efficient cost of supplying electricity to customers.
 - **Reduced discretionary allowances** – the reforms reduce discretionary retail allowances (such as headroom) that were originally included to support retail competition.
 - **Tariff-level caps** – the DMO framework will move from relying primarily on a reference annual bill to setting caps on individual tariff components.
 - **Solar sharer offer** – retailers will be required to offer a new ‘solar sharer’ style tariff designed to encourage electricity use during periods of high solar generation (see section 3.2).
 - **Expanded consumer protections** – the reforms extend protections to additional customer groups.
- **Regulatory changes:** The DMO regulations were amended in March 2026 to implement these reforms (reflected in the AER’s draft DMO determination).

Stakeholder comments

QCOSS said we should continue to adopt the usual approach to setting notified prices, rather than using the DMO tariffs directly in the Ergon Energy area. Among other reasons, the DMO is designed where there is effective competition, which is not the case in regional Queensland.¹²²

Draft decision

Consistent with the Minister’s preference, and taking into account the limited stakeholder feedback received, we have maintained our existing approach of basing the DMO comparison (and potential adjustments to notified prices) on reference bills rather than making a direct comparison of tariff rates.

It would be possible to align notified prices directly with those set for the SEQ DMO. The AER now sets tariff-level caps as part of the DMO framework and, in principle, these tariffs could be adopted

¹²² QCOSS, sub 10, pp 4-5.

in regional Queensland. However, doing so would represent a significant change to the current notified price framework. While it may reduce some duplication between the AER and QCA processes, some regulatory work would still be required. For example, for retail tariffs in regional Queensland that do not have direct equivalents in SEQ, prices will still need to be calculated and set under the notified price framework.

The current approach has also been used for a number of years and provides a stable and transparent method for ensuring notified prices do not exceed the SEQ DMO cap while explaining the cost drivers affecting electricity prices in regional Queensland.

To enable a comparison of the SEQ DMO with notified prices, we undertook the following steps:

- **DMO reference bills:** we converted the relevant SEQ flat tariff prices (tariff 11, tariff 11 with controlled load and tariff 20) into reference bills using the consumption estimates published by the AER.
- **Adjustments for a like-for-like comparison:** to ensure a consistent comparison between notified prices and the DMO:
 - we included GST in the notified price bills for the purposes of the comparison. DMO reference bills include GST, whereas notified prices are presented exclusive of GST
 - we used the DMO consumption levels to calculate comparable notified price bills, as the consumption levels used for the DMO differ from those used in our typical customer calculations.¹²³
- **Bill comparison:** we compared the relevant DMO reference bills (using the tariff rates and consumption levels published by the AER) to the notified price bills (where the notified price bills include the 3.09% SOA).

The results of this comparison are shown in Table 5.1, which presents the relevant DMO reference bills alongside the comparable notified price bills (including the SOA). Based on this comparison, we found that all notified price bills exceeded the equivalent DMO reference bills this year.

Accordingly, we consider it appropriate to discount the SOA included in small customer notified prices to ensure notified price bills do not exceed the relevant DMO reference bills. We propose to adjust the 3.09% SOA to:

- -5.62%, for all residential customer tariffs
- -2.13%, for controlled load tariffs
- -13.87%, for all small business customer tariffs.

Applying the same adjustment to all tariffs within each customer class ensures that tariff relativity is maintained and avoids creating incentives for customers to switch tariffs purely due to changes in relative price levels.

We intend to update this assessment using the reference bills derived from the AER's final DMO determination, expected to be released in May 2026.

¹²³ As of DMO 8, the AER no longer publishes a bill for the primary flat rate residential tariff when combined with secondary load control tariffs (tariff 11 plus a weighted average of tariffs 31 and 33). For comparison, we constructed a combined bill using the current DMO load control consumption level and the flat rate consumption level previously used in DMOs for combined tariffs.

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

Customer type	Relevant notified price tariff	DMO reference bill (A)	Notified price bill (incl 3.09% SOA) (B)	Difference (B – A)	Notified price bill (adjusted SOA) (C)	Difference (C – A)
Residential	11	\$1,927	\$2,105	\$178	\$1,927	\$0
	11+ 31, 33 ¹²⁴	\$2,194	\$2,384	\$190	\$2,194	\$0
Small business	20	\$3,744	\$4,482	\$738	\$3,744	\$0

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 SRES liabilities for each calendar year, while notified prices are set for each financial year.

As a result, at the time we make our final determination for notified prices, the 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.¹²⁵ If the CER’s final determination of SRES liabilities differs from its earlier forecast, this can lead to an over- or under-recovery of SRES costs in notified prices.

For 2025–26, there was an over-recovery of SRES costs, as the final SRES liabilities determined by the CER were lower than the forecast used in last year’s final determination (therefore, retailers were required to purchase fewer certificates than originally forecast).¹²⁶

We treat this over-recovery as a cost pass-through in notified prices, which reduces usage charges for all retail tariffs in 2026–27.^{127,128}

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

5.3 Metering costs – large customers

Consistent with our approach in previous determinations, we estimated large customer ADM costs for 2026–27 using confidential data provided by Energy Queensland for each large customer type.

The metering charges for large customers are set out in Chapter 6.¹²⁹

EEQ said this approach does not fully reflect differences in metering costs between customers because it is based on a representative consumption level of 750 MWh. EEQ recommended that

¹²⁴ Uses consumption for the primary residential flat-rate tariff, based on the combined profile published by the AER in DMOs prior to DMO 8.

¹²⁵ The CER typically determines the final SRES liabilities for the second half of the financial year around 9 months after our final determination.

¹²⁶ Reflecting the CER’s final SRES liabilities for calendar years 2025 and 2026. See Clean Energy Regulator, [Small-scale technology percentage](#), CER website, 2026, accessed 2 March 2026.

¹²⁷ Cost pass-through mechanisms are commonly used by regulators to manage the risk that forecast costs in regulated prices differ from the efficient costs of supply. These mechanisms are typically limited to events outside the control of the regulated entity, such as SRES liabilities.

¹²⁸ See Appendix B for further detail on how the SRES cost pass-through is calculated.

¹²⁹ Metering charges for large customers are identified separately. In contrast, small customer metering costs are incorporated into the relevant retail tariffs.

metering charges instead be based on meter type (types 1-4) and suggested implementing such an approach from 2027-28.¹³⁰

We have retained the current approach for the 2026-27 determination. However, as part of the next review, we will assess whether large customer metering costs could be set in a more cost-reflective manner, including the approach proposed by EEQ, taking into account the information available at that time.

5.4 Default retail tariff arrangements

Under the retail tariff schedule, default tariff arrangements apply where a small customer does not nominate a tariff when they become a standard contract customer of a retailer. In these circumstances, the retailer must assign the customer to tariff 11 (for residential customers) or tariff 20 (for small business customers).¹³¹ Importantly, these arrangements do not prevent customers from subsequently requesting assignment to another tariff.¹³²

The Minister's delegation requires us to assess whether there is an ongoing need for these default tariff arrangements.

Subject to stakeholder submissions, and consistent with our views in previous determinations, we consider there is merit in retaining the default tariff arrangements. These arrangements provide customers with certainty about the tariff they will be assigned if they do not nominate one. This is particularly important where a customer is deemed to have entered a standard retail contract with a retailer.¹³³

5.5 Additional issues raised by stakeholders

Stakeholders raised policy matters and other broader concerns, including:

- the CSO should be embedded in network charges instead of retail prices¹³⁴
- greater transparency should be provided on how we weigh the matters in section 26(1) of the QCA Act in our assessment, particularly regarding the rising groundwater problem in the Burdekin region¹³⁵
- that pricing reviews should occur more frequently to reduce shocks from large price adjustments.¹³⁶

The scope of our review of notified prices is determined by the Electricity Act and the Minister's delegation (see Chapter 1).

The design of the CSO, including how it is delivered, is a policy decision made by the Queensland Government. Stakeholders wishing to raise concerns about the CSO arrangements should therefore direct these matters to the Queensland Government.

¹³⁰ EEQ, sub 4, pp 6-7.

¹³¹ 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.

¹³² Queensland Government, *Gazette: Extraordinary*, no 28, vol 399, 6 June 2025, tariff schedule, p 227.

¹³³ 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 is revoked.

¹³⁴ Canegrowers, sub 1, p 8.

¹³⁵ QCAR, sub 8, pp 2-3.

¹³⁶ QCAR, sub 8, p 5.

We also note the comments about consideration of matters in section 26 of the QCA Act. These matters apply to our prices oversight regime under part 3 of the QCA Act, rather than the determination of notified prices under the Electricity Act. Matters such as groundwater management in the Burdekin region fall outside the scope of this review. Further, determinations of notified prices already occur regularly (annually) and sometimes more frequently where new tariffs are introduced.

6 Draft notified prices

Draft notified prices for 2026–27 are set out by customer type in Tables 6.1 to 6.7.¹³⁷

Table 6.1: Residential and small business customers (excl GST), 2026-27

Retail tariff	Fixed ^a (c/day)	Usage			Peak demand (\$/kW/mth)
		Off-peak/ flat (c/kWh)	Shoulder (c/kWh)	Peak (c/kWh)	
Tariff 11 – residential (flat-rate)	156.099	25.707			
Tariff 12D – residential time-of-use^b	135.429	16.576	22.067	36.069	
Tariff 12E – residential time-of-use^b	135.429	6.259	22.583	41.910	
Tariff 14C – residential time-of-use demand^{b,c}	118.440	16.576	22.067	18.861	7.086
Tariff 20 – small business (flat-rate)	180.037	27.468			
Tariff 22D – time-of-use^d	185.204	18.266	24.082	43.334	
Tariff 22E – time-of-use^d	185.204	7.683	23.625	51.007	
Tariff 24C – time-of-use demand^{d,e}	155.577	18.266	24.607	18.798	7.156

- Charged per metering point.
- 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.
- 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.

Table 6.2: Small customer interruptible supply and unmetered tariffs (excl GST), 2026-27

Retail tariff	Fixed ^a (c/day)	Usage Off-peak/ flat (c/kWh)
Tariff 31 – night rate (super economy)		15.362
Tariff 33 – controlled supply (economy)		15.485
Tariff 34 – small business interruptible supply	155.577	19.517
Tariff 91 – small business (unmetered)		25.486

- Charged per metering point.

¹³⁷ For a breakdown of notified prices by cost component, see Appendix C. For the draft gazette notice, including the draft notified prices tariff schedule, and terms and conditions for accessing each tariff, see Appendix D.

Table 6.3: Large business customers (excl GST), 2026-27

Retail tariff	Fixed (c/day)	Usage ^a	
		Below threshold	Above threshold
		(c/kWh)	
Tariff 43 — Business customer (over 100 MWh)	6344.188	20.053	17.781

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

Table 6.4: Large business and street lighting customers (excl GST), 2026-27

Retail tariff	Fixed (c/day)	Usage			Demand					
		Off-peak/flat	Shoulder	Peak	Off-peak/flat ^a	Shoulder	Peak	Off-peak/flat ^a	Shoulder	Peak
		(c/kWh)			(\$/kVA/mth)			(\$/kW/mth)		
Tariff 44A – over 100 MWh small (demand)	6344.188	19.351			23.092					
Tariff 49 – time-of-use energy^b	28621.187	18.093	36.115	41.423						
Tariff 50B – time-of-use demand^{b,c}	3704.987	18.093	20.192	41.423		5.972	14.283		6.636	15.870
Tariff 50C – time-of-use demand^{b,c}	3704.987	9.691	20.086	49.894		5.972	14.283		6.636	15.870
Tariff 60A – interruptible supply (primary)	5402.088	20.948								
Tariff 60B – interruptible supply (secondary)		20.948								
Tariff 71 – street lighting		33.333								

a. Demand – 4 pm to 9 pm weekdays.

b. 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.

c. 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.

Table 6.5: Very large business customers (excl GST), 2026-27

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)	27655.982	15.009	7.914	3.574	4.619
Tariff 51B – high voltage (CAC 33 kV)	18248.482	15.009	7.914	4.611	4.776
Tariff 51C – high voltage (CAC 22/11 kV Bus)	15639.082	15.009	7.914	5.170	5.871
Tariff 51D – high voltage (CAC 22/11 kV Line)	14702.482	15.009	7.914	9.125	11.718
Tariff 53 – high voltage (ICC)	27436.465	15.009		3.574	4.619
ICC site-specific – high voltage	2960.865	12.058		0.204	0.263

Table 6.6: Very large business customers (excl GST), 2026-27

Retail tariff	Fixed (c/day)	Usage	Connection unit (\$/day/unit)	Demand		(\$/kW/mth)
		Off-peak /flat (c/kWh)		Shoulder (\$/kVA/ mth)	Peak	
Tariff 52D – high voltage (CAC 66 kV) ^a	59743.782	13.132	7.914	3.771	6.284	2.302
Tariff 52E – high voltage (CAC 33 kV) ^a	31521.082	13.132	7.914	3.771	6.284	2.302
Tariff 52F – high voltage (CAC HV Bus) ^a	23693.182	13.132	7.914	8.327	13.878	2.302
Tariff 52G – high voltage (CAC HV Line) ^a	20883.482	13.132	7.914	12.334	20.559	2.302

- a. 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.

Table 6.7: Metering charges – large and very large business customers advanced meters (excl GST), 2026-27

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 and references

Stakeholder submissions

We received 12 submissions on the interim consultation paper. They are available on our website.

Stakeholder	Submission number	Date received
Canegrowers	1	13 February 2026
Caravan Parks Association of Queensland (CPAQ)	2	13 February 2026
Cotton Australia	3	13 February 2026
Ergon Energy Retail (EEQ)	4	13 February 2026
Ergon Energy Network & Energex (EEN and Energex)	5	13 February 2026
Hardwick, B	6	13 February 2026
Origin Energy Limited (Origin)	7	13 February 2026
Queensland Cane Agriculture & Renewables (QCAR)	8	13 February 2026
Queensland Consumers' Association	9	13 February 2026
Queensland Council of Social Service (QCOSS)	10	19 February 2026
Queensland Energy Users Network (QEUN)	11	12 February 2026
Queensland Farmers' Federation (QFF)	12	13 February 2026

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