Queensland Competition Authority

Technical appendices

Regulated retail electricity prices in regional Queensland 2023–24

March 2023

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APPENDIX A: MINISTER'S DELEGATIONS

Minister for Energy, Renewables and Hydrogen
Minister for Public Works and Procurement

Queensland Government

Our Ref: MN09299-2022

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15 DEC 2022

Professor Flavio Menezes
Chair
Queensland Competition Authority
GPO Box 2257
BRISBANE QLD 4001
By email: carola.hofmann@qca.org.au

Dear ~~Professor Menezes~~ Flavio

Pursuant to section 90AA of the *Electricity Act 1994* (the Act), I have delegated to the Queensland Competition Authority (QCA) the functions under section 90(1) of the Act for the determination of regulated retail electricity prices in regional Queensland for 2023-24. I am doing this in the form of two separate delegations for the 2023-24 tariff year. Delegation No. 1 is for the setting of notified prices for existing retail tariffs in the usual manner. Delegation No. 2 requests QCA make new electric vehicle (EV) tariffs aimed at further reducing the costs of operating EV's in regional Queensland by incentivising electricity use during the day. To achieve this, I ask QCA to consider modifying part of its cost build-up methodology for these tariffs. I also recognise this is a significant step for QCA so have quarantined this request from the standard annual delegation.

I also direct QCA under section 93 of the Act to decide the feed-in tariff (FiT) rate for the tariff year 1 July 2023 to 30 June 2024.

The Queensland Government is committed to ensuring affordable electricity prices for Queensland households and businesses. The Queensland Energy and Jobs Plan (the Plan) outlines how Queensland's energy system will transform to deliver clean, reliable and affordable power for generations. It leverages Queensland's natural advantages to:

- build a clean and competitive energy system for the Queensland economy and industries as a platform for accelerating growth
- deliver affordable energy for households and businesses, and support more rooftop solar and batteries
- drive better outcomes for workers and communities as partners in the energy transformation.

<u>General Price Setting</u>
The enclosed Delegation No. 1 and terms of reference for 2023-24 are generally consistent with the approaches of previous delegations. The Queensland Government's Uniform Tariff Policy (UTP) as described in the delegation continues to capture the need for consideration of the Default Market Offer (DMO) by QCA in its determination. Given the change in timing of the Australian Energy Regulator's final DMO decisions to late May each year, I recognise QCA will need extra time to consider the interplay of the South-East Queensland (SEQ) DMO with its own decision. Further, I consider it appropriate QCA conduct its usual process to determine all costs that contribute to notified prices, including considering all costs and benefits associated with small customer standing offers in SEQ.

The Plan sets a target of 100 per cent penetration of smart meters by 2030, hastening the rollout to help evolve Queensland's energy system. This target is flagged for replication nationally by the Australian Energy Market Commission in its recently released draft metering review. The target substantively addresses my earlier concerns about the slow deployment of smart meters in Queensland. I ask QCA to consider how it may enable retailers to recover costs associated with the provision of all metering services. However, as customers do not choose which meter they have it is important this is done in a fair and equitable way that is consistent with UTP so that similar customers do not pay different amounts simply based on the type of meter they have. QCA should set a retail fee for the additional costs of manually reading smart meters for customers who have voluntarily chosen to have the meter's remote communications functions disabled. This will ensure other customers are not paying for those private choices.

New EV tariffs

Thank you for the analysis on tariffs for EVs provided in QCA's final determination for regulated electricity prices for 2022-23. In consideration of this advice, Delegation No. 2 seeks the development of additional and new solar-soaker EV tariffs similar in structure to existing tariffs 12B and 22B, but with a larger differentiation between peak and daytime energy rates, to set clearer signals to consumers as when is the most cost-effective time to charge an EV.

Ensuring the state-wide rollout and integration of EVs is managed in a way that minimises the need for significant network infrastructure upgrades and makes use of existing spare capacity is essential to Queensland's electricity future. The Queensland Government has released the *Queensland's Zero Emission Vehicle Strategy 2022-2032* with EVs the key focus. These issues have also informed actions the Queensland Government has committed to in the Plan.

Battery charging is set to introduce new load onto the system and EV users will make decisions that will impact the electricity network in new ways. Uptake of EVs is growing quickly and the Queensland Government wants to encourage this uptake in a sustainable way that maximises beneficial outcomes for the electricity system and other electricity customers.

Regional Queensland is setting the pace in encouraging greater use of the abundant renewable energy. The improvement of solar-soaker tariffs that make the cheapest rate available from 9am to 4pm are critical. The Queensland Government's commitment to target 100 per cent smart meter uptake will enable more customers to adopt these types of tariffs. Although the structure of these tariffs offers incentives for customers, your advice confirmed the wholesale energy cost components used by QCA in setting notified prices are flat across all time periods. This includes during the day when there is typically a lot more energy generation from household and utility-scale solar photovoltaic systems.

Lowering retail energy charges during the day to better reflect the wholesale energy spot market, perhaps by using a weighting methodology as you advised would be your preferred approach, could create even greater savings for customers potentially further incentivising favourable charging behaviour when electricity supply is abundant, and cheaper. Sharper retail tariff price signals could be more attractive to many EV and battery owners, limiting the need for distribution network investment and benefitting all customers through bill savings. A key objective of these new solar-soaker tariffs is to incentivise households to charge EVs and batteries during the day when there is generally more available network capacity and renewable energy generation, and supply their household needs from their EV or battery during peak periods and ultimately reduce the charging costs for EV's in regional Queensland. It is anticipated the new tariffs will do this by providing stronger price signals and will lay the platform for commercial charge point operators to adopt similar time-based tariffs to incentivise charging behaviour.

FiT

The enclosed section 93 direction and associated terms of reference impose conditions and timeframes on QCA when undertaking its investigation. QCA is required to decide a FiT rate for 2023-24 using an avoided cost methodology.

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However, I note in QCA's recent monitoring report on solar FiTs in SEQ for 2021-22 (October 2022), QCA identifies the average SEQ residential FiT in the June quarter 2022 was 5.7 cents per kilowatt-hour. In contrast the regional FiT for 2022-23 is 9.3 cents per kilowatt-hour. I ask QCA to consider if the methodology used in previous years remains appropriate and continues to reasonably reflect actual avoided costs to retailers when purchasing energy from small customers. I anticipate this will necessitate public consultation in deciding the 2023-24 FiT.

Public consultation has long formed a vital part of QCA's process for determining retail electricity prices. The terms of reference of both delegations set out the consultation needs and requires QCA to publish its draft determinations in February 2023 and its final determinations by 9 June 2023. I anticipate the processes for both delegations will run simultaneously and appear seamless to stakeholders.

Regional customers continue to benefit from the electricity cost protection provided by UTP and the benefits of Queensland-owned assets. The Plan is a plan for all Queenslanders – a Plan for the future that will deliver clean, reliable and affordable power for generations and position the State for growth and prosperity.

The Department of Energy and Public Works (DEPW) will be available to consult with QCA on the 2023-24 price determination and Tariff Schedule. If you need more information or help with this matter, [redacted] Executive Director, Energy, DEPW can be contacted on [redacted] or [redacted]

Yours sincerely

Mick de Brenni MP
Minister for Energy, Renewables and Hydrogen
Minister for Public Works and Procurement

Encl. Section 90AA Delegation No. 1 and Terms of Reference
Section 90AA Delegation No. 2 and Terms of Reference
Section 93 Direction and Terms of Reference

DELEGATION TO QCA

DEPARTMENT OF ENERGY AND PUBLIC WORKS

Electricity Act 1994

ELECTRICITY (MINISTERIAL) DELEGATION (NO. 1) 2022 to the Queensland Competition Authority (QCA)

Preliminary matters

1. The preliminary matters form part of this delegation.

2. ***QCA*** means the Queensland Competition Authority established under the *Queensland Competition Authority Act 1997.*

3. Section 89A of the *Electricity Act 1994* (the Act) relevantly provides:
   price determination see section 90(1).
   pricing entity means—
   (a) the Minister; or
   (b) QCA, if the Minister delegates a function of the Minister under section 90(1) to QCA.

4. Section 90(1) of the Act provides:
   The Minister must, for each tariff year, decide (a ***price determination****) the prices, or the methodology for fixing the prices, that a retailer may charge its standard contract customers for all or any of the following—*
   (a) customer retail services;
   (b) charges or fees relating to customer retail services;
   Examples—
   •charges or fees for late or dishonoured payments
   •credit card surcharges for payments for the services
   (c) other goods and services prescribed under a regulation.

5. Section 90(5) provides:
   In making a price determination, the pricing entity—
   (a) must have regard to all of the following—
   (i) the actual costs of making, producing or supplying the goods or services;
   (ii) the effect of the price determination on competition in the Queensland retail electricity market;
   (iii) if QCA is the pricing entity—any matter the pricing entity is required by delegation to consider; and
   (b) may have regard to any other matter the pricing entity considers relevant.

6. Section 90AA(1) of the Act provides that the Minister may delegate to the QCA all or any of the Minister's functions under section 90(1) of the Act.

7. Section 90AA(2) of the Act provides that delegation to the QCA may state the terms of reference of the price determination.

8. Section 90AA(3) of the Act provides what the terms of reference may specify and how the terms of reference may apply.

9. The terms of reference provided for in sections 90AA(2) and (3) of the Act are contained in the Schedule to this delegation and comprise the matters under section 90(5)(a)(iii) of the Act that the QCA as the pricing entity is required by delegation to consider.

Powers delegated

10. Subject to the conditions of this delegation, I delegate all of the Minister's functions under section 90(1) of the Act to the QCA for the tariff year 1 July 2023 to 30 June 2024.

Conditions of delegation

11. The delegated functions of the Minister must only be exercised for the purpose of deciding the prices, or the methodology for fixing the prices that a retail entity may charge its Standard Contract Customers in Queensland, other than Standard Contract Customers in the Energex distribution area.

12. In exercising the delegated functions under section 89A, the QCA, as the pricing entity, must have regard to all of the matters set out in section 90(5)(a) of the Act, which includes the terms of reference in the Schedule to this delegation.

13. In exercising the delegated functions, the QCA must have regard to all relevant statutory provisions, whether referred to in this delegation or not.

Revocation

14. All earlier delegations of the Minister's powers under section 90(1) of the Act are revoked.

15. Unless earlier revoked in writing, this delegation ceases upon gazettal by the QCA of its final price determination on regulated retail electricity tariffs for the 2023–24 tariff year under section 90AB of the Act.

Note to delegation

16. Statutory references are to be construed as including all statutory provisions consolidating, amending or replacing the statute referred to and all regulations, rules, by-laws, local laws, proclamations, orders, prescribed forms and other authorities pursuant thereto.

This delegation is made by **The Honourable Mick de Brenni MP**
Minister for Energy, Renewables and Hydrogen and
Minister for Public Works and Procurement:

Signed:

The Honourable Mick de Brenni MP
Minister for Energy, Renewables and Hydrogen and
Minister for Public Works and Procurement

Dated: 14/12/2022

DELEGATION TO QCA

SCHEDULE
Terms of Reference
Section 90(5)(a)(iii) and 90AA of the Act

Period for which the price determinations will apply (section 90AA(3)(a) of the Act)

1. These Terms of Reference apply for the tariff year 1 July 2023 to 30 June 2024.

Policies, principles and other matters the QCA must consider when working out the notified prices and making the price determination (sections 90(5)(a)(iii), 90AA(3)(c) and 90AA(3)(d) of the Act)

2. The policies, principles and other matters that the QCA is required by this delegation to consider are:

   (a) Uniform Tariff Policy — the Government's Uniform Tariff Policy, which provides that, wherever possible, customers of the same class should pay no more for their electricity, and should be able to pay for their electricity via similar common price structures, regardless of their geographic location;

   (b) Framework – use of the Network (N) plus Retail (R) cost build-up methodology when working out the notified prices and making the price determination, where N (network cost) is generally treated as a pass-through and R (energy and retail cost) is determined by the QCA;

   (c) When determining the N components for each regulated retail tariff, where retained:

      (i) For residential and small business customer Tariffs 11, 20, 31 and 33 - basing the network cost component on the relevant Energex network charges to be levied by Energex and the relevant Energex tariff structures;

      (ii) For all other residential and small business customer tariffs, except for those set out in c(iii) below - basing the network cost component on the price level of the relevant Energex network charges to be levied by Energex, but utilising the relevant Ergon Energy Corporation Limited (**EECL**) tariff structures;

      (iii) For tariffs 62A, 65A, 66A and all large customer tariffs – basing the network cost component on the relevant EECL network charges to be levied by EECL in the 'East distribution pricing zone - Transmission pricing zone T1';

   (d) Small customer metering costs:
      (i) Basing small customer retail metering service costs, an element of R components for each regulated tariff, on the Energex rate for standard

Type 6 small customer metering services plus costs incurred by retailers operating in the Energex distribution area for small customer advanced digital metering services while having regard to the rate of replacement of distributor meters with advanced digital meters; and

(ii) Setting a retail charge based on Ergon Energy Retail's averaged costs of manually reading a Type 4A meter to apply to Standard Contract Customers who have voluntarily chosen to have the remote communication function of the advanced digital metering installed at their premises disabled.

(e) Default tariffs – maintaining the existing nomination of a primary tariff for each class of small customer to apply to a customer's electricity account in the event the customer does not nominate a primary tariff when opening an electricity account;

(f) Continue enabling retailers to also charge Standard Contract Customers for the following customer retail services that are not included in regulated retail tariffs:

(i) Amounts in accordance with a program or scheme for the purchase of electricity from renewable or environmentally-friendly sources (whether or not those additional amounts are calculated on the basis of the customer's electricity usage), but only if:
(a) the customer voluntarily participates in such program or scheme;
(b) the additional amount is payable under the program or scheme; and
(c) the retailer gives the customer prior written notice of any change to the additional amount payable under the program or scheme.

Consultation Requirements (section 90AA(3)(e) of the Act)

Interim Consultation Paper

3. The QCA must publish an interim consultation paper identifying key issues to be considered when making the price determination.

4. The QCA must publish a written notice inviting submissions about the interim consultation paper. The notice must state a period during which anyone can make written submissions to the QCA about issues relevant to the price determination.

5. The QCA must consider any submissions received within the consultation period and make them available to the public, subject to normal confidentiality considerations.

Consultation Timetable

6. The QCA must publish an annual consultation timetable within two weeks after submissions on the interim consultation paper are due, which can be revised at the

discretion of the QCA, detailing any proposed additional public papers and information sessions that the QCA considers would assist the consultation process.

Information Sessions and Additional Consultation

7. As part of the interim consultation paper and in consideration of submissions in response to the interim consultation paper, the QCA must consider the merits of additional public consultation (information sessions and papers) on identified key issues.

Draft Price Determination

8. The QCA must investigate and publish its draft price determination on regulated retail electricity tariffs, with each tariff (to the extent practicable) to be presented as bundled prices appropriate to the retail tariff structure.

9. The QCA must publish a written notice inviting submissions about the draft price determination. The notice must state a period during which anyone can make written submissions to the QCA about issues relevant to the draft price determination.

10. The QCA must consider any submissions received within the consultation period and make them available to the public, subject to normal confidentiality considerations.

Final Price Determination

11. The QCA must investigate and publish its final price determination on regulated retail electricity tariffs, with each tariff (to the extent practicable) to be presented as bundled prices appropriate to the retail tariff structure, and gazette the retail tariffs in the form of a Tariff Schedule.

Time frame for QCA to make and publish reports (section 90AA(3)(b) of the Act)

12. The QCA must make its reports available to the public and, at a minimum, publicly release the papers and price determinations listed in paragraphs 3 to 11.

13. The QCA must publish the interim consultation paper for the 2023–24 tariff year no later than one month after the date of this Delegation.

14. The QCA must publish the draft price determination on regulated retail electricity tariffs no later than February 2023.

15. The QCA must publish the final price determination on regulated retail electricity tariffs for the 2023–24 tariff year and have the retail tariffs gazetted no later than 9 June 2023.

(SCHEDULE ENDS)

DELEGATION TO QCA

DEPARTMENT OF ENERGY AND PUBLIC WORKS

Electricity Act 1994

ELECTRICITY (MINISTERIAL) DELEGATION (NO. 2) 2022
to the Queensland Competition Authority (QCA)

Preliminary matters

1. The preliminary matters form part of this delegation.

2. ***QCA*** means the Queensland Competition Authority established under the *Queensland Competition Authority Act 1997.*

3. Section 89A of the *Electricity Act 1994* (the Act) relevantly provides:
   price determination see section 90(1).
   pricing entity means—
   (a) the Minister; or
   (b) QCA, if the Minister delegates a function of the Minister under section 90(1) to QCA.

4. Section 90(1) of the Act provides:
   The Minister must, for each tariff year, decide (a ***price determination****) the prices, or the methodology for fixing the prices, that a retailer may charge its standard contract customers for all or any of the following—*
   (a) customer retail services;
   (b) charges or fees relating to customer retail services;
   Examples—
   •charges or fees for late or dishonoured payments
   •credit card surcharges for payments for the services
   (c) other goods and services prescribed under a regulation.

5. Section 90(5) provides:
   In making a price determination, the pricing entity—
   (a) must have regard to all of the following—
   (i) the actual costs of making, producing or supplying the goods or services;
   (ii) the effect of the price determination on competition in the Queensland retail electricity market;
   (iii) if QCA is the pricing entity—any matter the pricing entity is required by delegation to consider; and
   (b) may have regard to any other matter the pricing entity considers relevant.

6. Section 90AA(1) of the Act provides that the Minister may delegate to the QCA all or any of the Minister's functions under section 90(1) of the Act.

7. Section 90AA(2) of the Act provides that delegation to the QCA may state the terms of reference of the price determination.

8. Section 90AA(3) of the Act provides what the terms of reference may specify and how the terms of reference may apply.

DELEGATION TO QCA

9. The terms of reference provided for in sections 90AA(2) and (3) of the Act are contained in the Schedule to this delegation and comprise the matters under section 90(5)(a)(iii) of the Act that the QCA as the pricing entity is required by delegation to consider.

Power to delegate

10. Under section 90AA(1) of the Act, the Minister may delegate to the QCA all or any of the Minister's functions under section 90(1) of the Act.

Powers delegated

11. I delegate the functions of the Minister under section 90(1) of the Act to the QCA for the 2023-24 tariff year, in respect of the following maters:

    (a) developing up to two new standard retail tariffs (together, the **new tariffs**) to be included in the 2023-24 Tariff Schedule, to be amended if required, based on the residential and small business network tariffs that underpin existing retail standard tariffs 12B and 22B:
        (i) a residential 3-rate time of use energy tariff; and
        (ii) a small business 3-rate time of use energy tariff.

    (b) deciding the prices, or the methodology for fixing the prices, for the new tariffs developed under paragraph 11(a) that a retail entity may charge its Standard Contract Customers in Queensland (other than Standard Contract Customers in the Energex distribution area) for the new retail tariffs; and

    (c) adding the new tariffs as standard tariffs to the Tariff Schedule pursuant to section 90(3)(c) of the Act.

12. The new retail tariffs must take effect on 1 July 2023 for the 2023-24 tariff year.

13. Pursuant to section 90(5)(a)(iii) of the Act, in exercising the functions specified in paragraph 11 above, the QCA must have regard to the terms of reference in the schedule.

Conditions of delegation

14. The delegated functions of the Minister must only be exercised for the purpose of deciding the prices, or the methodology for fixing the prices that a retail entity may charge its Standard Contract Customers in Queensland, other than Standard Contract Customers in the Energex distribution area.

15. In exercising the delegated functions under section 90, the QCA, as the pricing entity, must have regard to all of the matters set out in section 90(5) of the Act, and the terms of reference in the Schedule to this delegation.

16. In exercising the delegated functions, the QCA must have regard to all relevant statutory provisions, whether referred to in this delegation or not.

DELEGATION TO QCA

Revocation

17. This delegation operates concurrently with any previous delegations to the QCA still in force. This delegation prevails over any previous delegations in force to the extent of any inconsistency.

18. Unless earlier revoked in writing, this delegation ceases upon gazettal by the QCA of its final price determination on the regulated retail electricity matters set out in paragraph 11 for the 2023-24 tariff year under section 90AB of the Act.

Note to delegation

19. Statutory references are to be construed as including all statutory provisions consolidating, amending or replacing the statute referred to and all regulations, rules, by-laws, local laws, proclamations, orders, prescribed forms and other authorities pursuant thereto.

This delegation is made by the Honourable Mick de Brenni MP
Minister for Energy, Renewables and Hydrogen and
Minister for Public Works and Procurement:

Signed:

The Honourable Mick de Brenni MP
Minister for Energy, Renewables and Hydrogen and
Minister for Public Works and Procurement

Dated: 14/12/2022

DELEGATION TO QCA

SCHEDULE
Terms of Reference
Section 90(5)(a)(iii) and 90AA of the Act

Period for which the price determinations will apply (section 90AA(3)(a) of the Act)

1. The price determination for the new tariffs takes effect from 1 July 2023 and remains in force until the end of the 2023-24 tariff year.

Policies, principles and other matters the QCA must consider when working out the notified prices and making the price determination (sections 90(5)(a)(iii), 90AA(3)(c) and 90AA(3)(d) of the Act)

2. The policies, principles and other matters that the QCA is required by this delegation to consider for the new retail tariffs are:

   (a) Uniform Tariff Policy — the Government's Uniform Tariff Policy, which provides that, wherever possible, customers of the same class should pay no more for their electricity, and should be able to pay for their electricity via similar common price structures, regardless of their geographic location;

   (b) For the new tariffs:

      i. Framework – use of the Network (N) plus Retail (R) cost build-up methodology when working out the notified prices and making the price determination, where N (network cost) is generally treated as a pass-through and R (energy and retail cost) is determined by the QCA;

      ii. When determining the N components, basing the network cost component on the price level of the relevant Energex network charges to be levied by Energex, but using the relevant Ergon Energy Corporation Limited (EECL) tariff structures; and

      iii. When determining the R component, use of relevant data and assumptions developed and applied under the *Electricity (Ministerial) Delegation (No. 1) 2022 to the Queensland Competition Authority (QCA)*, and application of a methodology whereby the R component delivers greater price differentials between peak and non-peak periods compared to Tariffs 12B and 22B, in a way that may encourage more energy use during the day;

Consultation Requirements (section 90AA(3)(e) of the Act)

Interim Consultation Paper

3. The QCA must publish an interim consultation paper identifying key issues to be considered when making the price determination.

4. The QCA must publish a written notice inviting submissions about the interim consultation paper. The notice must state a period during which anyone can make written submissions to the QCA about issues relevant to the price determination.

5. The QCA must consider any submissions received within the consultation period and make them available to the public, subject to normal confidentiality considerations.

Consultation Timetable

6. The QCA must publish a consultation timetable within two weeks after submissions on the interim consultation paper are due, which can be revised at the discretion of the QCA, detailing any proposed additional public papers and information sessions that the QCA considers would assist the consultation process.

Information Sessions and Additional Consultation

7. As part of the consultation process and in consideration of any relevant consultation already undertaken, the QCA must consider the merits of additional public consultation (information sessions and papers) on identified key issues.

Draft Price Determination

8. The QCA must investigate and publish its draft price determination on the new tariffs with each tariff (to the extent practicable) to be presented as bundled prices appropriate to the retail tariff structure.

9. The QCA must publish a written notice inviting submissions about the draft price determination. The notice must state a period during which anyone can make written submissions to the QCA about issues relevant to the draft price determination.

10. The QCA must consider any submissions received within the consultation period and make them available to the public, subject to normal confidentiality considerations.

Final Price Determination

11. The QCA must investigate and publish its final price determination on the new tariffs with each tariff (to the extent practicable) to be presented as bundled prices appropriate to the retail tariff structure and gazette the retail tariffs in the form of a Tariff Schedule.

Time frame for QCA to make and publish reports (section 90AA(3)(b) of the Act)

12. The QCA must make its reports available to the public and, at a minimum, publicly release the papers and price determinations listed in paragraphs 3 to 11.

13. The QCA must publish the draft price determination on regulated retail electricity tariffs no later than February 2023.

14. The QCA must publish the full 2023-24 Tariff Schedule, amended as required to include the new tariffs in the Queensland Government gazette no later than 9 June 2023.

(SCHEDULE ENDS)

Minister for Energy, Renewables and Hydrogen
Minister for Public Works and Procurement

1 William Street
Brisbane Queensland
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Our Ref: MN01147-2023

17 February 2023

Professor Flavio Menezes
Chair
Queensland Competition Authority
GPO Box 2257
BRISBANE QLD 4001
By email: [redacted]

Dear Professor Menezes

I am writing to you to extend the time for publication of the Queensland Competition Authority's (QCA) draft decisions in relation to the functions I delegated to the QCA on 15 December 2022.

The delegations I have issued to the QCA pursuant to section 90AA of the *Electricity Act 1994* require the QCA to consider the Default Market Offer and publish its draft decisions by February 2023. I note on 27 January 2023, the Australian Energy Regulator announced it will delay its 2023-24 Default Market Offer draft decisions, including its South-East Queensland decision, from February 2023 to the week of 13 March 2023.

Specifically, the following changes are to be effected to each delegation:

1. ELECTRICITY (MINISTERIAL) DELEGATION (NO. 1) 2022
   SCHEDULE Terms of Reference
   Section 14 to be replaced with:
   14. The QCA must publish the draft price determination on regulated retail electricity tariffs contemporaneous with the Australian Energy Regulator publishing the 2023-24 draft South-East Queensland Default Market Offer decision.

2. ELECTRICITY (MINISTERIAL) DELEGATION (NO. 2) 2022
   SCHEDULE Terms of Reference
   Section 13 to be replaced with:
   13. The QCA must publish the draft price determination on regulated retail electricity tariffs contemporaneous with the Australian Energy Regulator publishing the 2023-24 draft South-East Queensland Default Market Offer decision.

If you need more information or help with this matter, [redacted] Executive Director, Department of Energy and Public Works can be contacted on [redacted] or email [redacted].

Yours sincerely

Mick de Brenni MP
Minister for Energy, Renewables and Hydrogen
Minister for Public Works and Procurement

APPENDIX B: ENERGY COST APPROACH

This appendix provides an overview of ACIL Allen's (ACIL's) methodology and approach to estimating energy costs, including why we consider the estimates are appropriate.[1] In addition, we address some of the more technical issues raised by stakeholders that are not addressed in the main report.

The energy costs discussed are:

- wholesale energy costs (part A)
- other energy costs (part B).

Part A: Wholesale energy costs

Overview

A retailer incurs wholesale energy costs when purchasing electricity from the National Electricity Market (NEM) and engaging in risk management strategies, to meet the demand of its customers. The NEM is a volatile market where spot prices are settled every 5 minutes and currently can range from –$1,000 to $15,500 per megawatt hour (MWh).[2] To manage spot price volatility (spot price risk), retailers typically adopt a range of hedging strategies, including:

- purchasing financial derivatives—such as ASX Energy contracts[3] and over-the-counter (OTC) contracts[4]
- entering long-term power purchase agreements (PPAs) with electricity generators[5]
- investing in their own electricity generators (also known as vertical integration).[6]

We engaged ACIL to assist us in estimating wholesale energy costs for these customer groups:

- Energex area
  - residential and small business customers (small customers) and unmetered customers
  - customers on load control tariffs available to both residential and small business customers
  - customers on load control tariffs available to only small business customers.

[1] ACIL Allen, Estimated Energy Costs, draft report, prepared for the QCA, February 2023.
[2] The minimum spot price (market floor price) and the maximum spot price (market price cap) are defined in chapter 3 of the National Electricity Rules. The market price cap is published by the AEMC every February and is effective from 1 July. For more information, see www.aemc.gov.au.
[3] ASX Energy contracts are standardised exchange-traded financial derivatives for electricity that allow retailers to manage spot price risk. For more information, see https://www.asxenergy.com.au/.
[4] Unlike the standardised exchange-traded ASX contracts, OTC contracts are bilateral agreements and therefore allow for a high degree of flexibility in the terms of the arrangements.
[5] PPAs are long-term bilateral contracts between a generator and a purchaser for the sale and supply of electricity. Generators receive payments over the life of the PPAs to underwrite their investments. Purchasers of PPAs (such as retailers) can manage the spot price risk by locking in their electricity costs.
[6] This business model allows the retail and generation arms of the same business to better manage spot price risk by having income streams from the NEM and end users. This is because, during periods of low spot prices, the lower generation revenue can be partially compensated by the income received from retail customers. Conversely, during periods of high spot prices, the higher generation revenue can partially offset the higher costs that the retail arm incurs when sourcing electricity at the prevailing spot price.

- Ergon area
  - small, large business and street lighting customers
  - very large business customers
  - customers on load control tariffs available to large business customers.

Consistent with previous years, ACIL estimated wholesale energy costs using a market hedging approach. As discussed in section 4.2.1 of the main report, this approach is designed to simulate the NEM from a retailer's perspective, including by incorporating a hedging strategy that a prudent retailer would adopt to manage spot price risk in the NEM.

Broadly, the wholesale energy costs for a given year are a function of:

- demand considerations
- wholesale energy spot prices
- retailers' hedging strategies and forward contract prices.

Demand considerations

ACIL used its stochastic demand model to develop 51 weather-influenced simulations of hourly demand for the net system load profiles (NSLPs), advanced digital meters (ADMs) profiles, controlled load profiles (CLPs) and the system-wide demand for Queensland. The model uses:

- temperature data from 1970–71 to 2020–21, historical demand profiles from 2018–19 to 2020–21 and the expected uptake of rooftop solar photovoltaic (PV)[7]
- AEMO's latest demand forecast for 2023–24, including energy forecasts from AEMO's central scenario and the seasonal peak demands with a 10% probability of exceedance (POE)[8], 50% POE and 90% POE.[9]

The weather-influenced, system-wide hourly demand (i.e. the demand satisfied by scheduled and semi-scheduled generation[10]) is then used to simulate the expected spot prices, while the simulated NSLPs, ADM profiles and CLPs were required to develop separate wholesale energy estimates for different customer groups.

ACIL's report specifies the relevant historical demand profiles and load data sources.[11] For retail tariffs with limited historical profiles (i.e. the load control tariffs for small and large business customers), ACIL used the relevant representative demand profiles that we recently developed using data from Energy Queensland. We consider this approach is appropriate while customer uptake of these tariffs is not widespread and there is limited usage data available.[12]

[7] The demand data have not been updated to include 2021–22 due to some anomalies in NSLP data since the commencement of five-minute settlement. More details are available in chapter 2 of ACIL's report.

[8] POE is the probability of whether an electricity demand forecast will be met or exceeded. For example, a demand level with a 10% POE implies that there is a 10% probability of the forecast being met or exceeded. The 10% POE forecast is mathematically expected to be met or exceeded once in 10 years and represents demand under more extreme weather conditions (than, for example, a 50% POE forecast).

[9] AEMO, *2022 Electricity Statement of Opportunities*, August 2022.

[10] Generators with controllable output and a capacity over 30 MW are usually classified as scheduled generation. This type of generation is largely made up of coal and gas-fired generation as well as hydropower plants. In contrast, generators with intermittent output (such as wind and solar farms) and a capacity over 30 MW are generally classified as semi-scheduled generation. If required, for system security, AEMO can control the output of scheduled generation but can only constrain the output of semi-scheduled generation.

[11] Table 2.1 (p 10) of ACIL's report summarises the sources of load data used.

[12] QCA, *Supplementary review: Regulated retail electricity prices for 2020–21*, final determination, October 2020.

In addition, this year, ADM data has been used to better approximate customers' consumption patterns and inform our wholesale energy cost estimates (see section 4.2.1 of the main report).

Wholesale energy spot prices

To simulate a range of expected spot prices, ACIL has developed several datasets that reflect the supply dynamics within the NEM, including:

- thermal power plant availability—ACIL uses a stochastic outage model to develop 11 hourly power station availability simulations. The outage simulation is designed to reflect the probability of various planned and forced outages of generators and the effect that outages would have on spot prices
- renewable energy resource traces—ACIL uses a renewable energy resource model to estimate a set of traces[13] that reflects the availability and quality of renewable resources/generation (such as wind and solar) in different NEM regions, taking into account weather and geographical conditions
- generation information—ACIL maintains a reference case projection of the NEM that incorporates generator-related data, such as costs and technological characteristics of generators, contract cover and portfolio ownership structure. It updates the reference case each quarter in response to the latest supply changes announced in terms of new investments, retirements, fuel costs and generator availability.

Since February 2022, thermal generators have faced higher fuel costs. International gas prices and thermal coal export prices have been higher and more volatile as the war in Ukraine and sanctions against Russia added uncertainty to markets already impacted by global supply constraints.[14] To reflect this development, ACIL has updated its coal price forecasts using the recent Bloomberg Intercontinental Exchange (ICE) forward curve for the Newcastle coal export price. Gas price projections have also been updated by incorporating recent domestic gas prices and LNG export prices.

ACIL incorporates changes to the existing generation supply where market participants have formally announced changes, including mothballing, closure and change in the operating approach of power plants. Near-term new generators are included, should ACIL deem these plants to be committed projects.

ACIL's forecast of the generation supply and costs within the NEM also closely aligns with AEMO's latest Integrated System Plan (ISP) and Electricity Statement of Opportunities (ESOO).[15] To achieve this, ACIL routinely compares its detailed assumptions with AEMO's ISP and ESOO findings, including the technical parameters of generators, fuel prices and interconnector expansions. ACIL investigated any deviation in assumptions and adopted AEMO's findings if the deviation could not be justified. However, to date, ACIL's assumptions closely align with AEMO's findings.

Spot price simulation

ACIL uses a proprietary electricity model (PowerMark) to generate 561 simulations of 8,760 hourly wholesale electricity spot prices for 2023–24 and dynamically simulate the behaviour of generators in the NEM by:

[13] These traces are consistent with the weather conditions for the demand profiles from 2018–19 to 2020–21. Such an approach maintains the appropriate correlation between various demand profiles and renewable energy resource traces, as both electricity demand and renewable generation vary with weather patterns.

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

[15] The ISP and ESOO contain extensive technical data that inform the decision-making of interested parties as they assess opportunities in the NEM.

- allowing each portfolio of generators to optimise its bids to maximise profit
- considering the stochastic demand profiles
- thermal power plant availability, renewable energy resource traces and generation information.

This allows ACIL's estimates to account for:

- changes in generators' bidding behaviour caused by changing market conditions, such as the recent influx of renewable generation
- changes in underlying costs (including fuel costs)
- changes due to the recent government interventions, including assuming that the implemented price caps apply to all relevant fuel supply contracts and will be in force throughout the entire 2023–24 financial year.

ACIL also attempted to capture any heightened market volatility by undertaking a large number of simulations (over 500) to account for variations in demand, thermal plant availability, output of renewable generation and spot price outcomes. We note that ACIL's wholesale spot price modelling broadly aligns with the market's expectations of spot price outcomes (ASX contracts) for 2023–24.[16]

Retailers' hedging strategies and contract prices

To simulate the wholesale energy costs incurred by a retailer that manages spot price risk, ACIL developed a hedging methodology based on the standard ASX Energy base and cap contracts.

ACIL uses its hedge model to test a substantial number of strategies to derive a hedging strategy (and contract volume) with the lowest cost and variance, considering the latest simulated demand profiles, spot prices and trade-weighted contract prices. ACIL evaluated multiple strategies by varying the mix of ASX contracts for each quarter and analysing the resulting distribution of wholesale energy costs for each strategy.

ACIL estimates contract prices for 2023–24 by calculating the trade-weighted average of ASX Energy settlement prices of quarterly base and cap contracts and call options[17] for ASX base contracts, using contract prices and trade volumes for Queensland until 20 January 2023 inclusive.

Trading of ASX contracts tends to commence a number of years before the relevant financial year. For example, trading for 2023–24 ASX base contracts commenced as early as March 2020. This is a reflection of how market participants (such as retailers) purchase ASX contracts to lock in their costs in advance and manage spot price risk.[18]

Compared to last year, 2023–24 trade-weighted contract prices have increased:

- for base contracts—between $26.68 and $43.95/MWh.
- for cap contracts—between $5.27 and $6.63/MWh.[19]

[16] More details are available in chapter 4 of ACIL's report.
[17] In this context, call options are a type of financial derivative that gives the holder the right, but not the obligation, to purchase ASX base contracts at a predetermined price (known as the 'strike price') and volume. In exchange for the right to exercise the option, the holder (buyer) will pay a premium to the seller of the call option (regardless of whether the holder chooses to exercise the option).
[18] More details on ACIL's approach are available in chapter 4 of its report.
[19] Table 4.1 (p 45) of ACIL's report summarises contract prices and percentage changes over the last four quarters.

ACIL applied the hedging methodology (together with the simulated spot prices) to derive 561 annual hedged energy costs for a given demand profile. The 95th percentile of the distribution of hedged costs was used as the final estimate of the wholesale energy costs.

Addressing stakeholder submissions

EER's comments on some matters are addressed in the main report. EER also suggested that we update our spot price modelling to address:

- the increasing incidence of negative spot prices due to higher levels of solar generation[20]
- the current liquidity of ASX contracts (specifically cap contracts), noting that retailers are increasingly reliant on more expensive OTC contracts.[21]

Incidence of negative spot prices

Consistent with EER's view, we consider the continued installation of rooftop and utility-scale solar PV systems will likely increase the number of negative spot prices during daylight hours. For 2023–24, ACIL estimated that the proportion of spot price outcomes less than or equal to zero ranges between 8 and 10 per cent, compared to a historical range of less than 6 per cent. We are therefore satisfied that our spot price modelling adequately takes into account recent developments and market volatility, based on the latest available information.

Current liquidity of ASX contracts

We note that an indirect indicator of contract liquidity is the cumulative trade volume. Except for 2021–22[22], the cumulative trade volume for cap contracts (to date for 2023–24) is on par with the trade volumes in previous years.[23] On this basis, we are satisfied the liquidity for cap contracts has remained reasonably stable, and the trade-weighted ASX cap price continues to be a reasonable proxy for the costs of sourcing this type of contract as part of a broader hedge portfolio.

Further, ASX cap contracts are just one of the many instruments that retailers use to hedge their exposure to spot price movements. In reality, retailers will likely have access to OTC contracts, PPAs and their own generating units to act as hedging instruments. As such, we do not expect that retailers will build their entire hedge portfolio using solely ASX contracts. This means that the volume of ASX contracts traded would naturally be less than the volume associated with all hedging instruments that retailers adopt in practice.

The key reason that we rely on ASX contracts is because the information for these contracts is publicly available, transparent and verifiable, whereas information for other hedging instruments tends to be commercial-in-confidence.[24]

EER also noted retailers are increasingly reliant on more expensive OTC contracts. We have investigated this issue by comparing the ASX data with OTC contract data. At this stage, we have found no evidence of OTC prices being consistently higher (or lower) than ASX contract prices. To date, there is a high level of consistency between both prices, with absolute differences[25] typically being between 1 and 2 per cent for contracts with similar specifications.

[20] EER, sub. 5, pp 5–6.
[21] EER, sub. 5, pp 6–7.
[22] In 2021–22, trade volume was lower due to the transition to 5-minute settlement.
[23] See Figure 3.2 in ACIL's report.
[24] See Figure 3.2 on p 37 of ACIL's report, which charts the cumulative trade volumes of cap contracts in Queensland.
[25] This refers to the difference expressed in absolute numbers—that is, the difference without regard to whether it is a negative or positive difference.

Other issues

EER also suggested:

- the need for a trigger to pass through wholesale energy costs that were incurred due to an extraordinary event
- the 95th percentile of hedged costs should be retained as the estimate for the wholesale energy cost for a given customer group
- publication of ACIL's energy modelling data to enhance the transparency of our methodology for estimating wholesale energy costs.[26]

In relation to a trigger for extraordinary events, we note prudent retailers reduce their exposure to unexpected or extraordinary events by engaging in a variety of hedging strategies, including via trading in ASX contracts. Our market hedging approach is designed to reflect this dynamic and the conditions of ASX contract markets. The purchase of ASX contracts allows retailers to mitigate some of the impacts of extraordinary events by locking in a proportion of their costs in advance. Any events with longer-term implications would also be captured in the ASX contract markets, as these markets are forward-looking and reflect market participants' expectations of future spot prices.

Consistent with EER's views, we consider retaining the 95th percentile hedged cost as the estimate for wholesale cost remains appropriate. We recognise there may be some residual volume and price risk not captured by the spot price and hedge modelling. The key reason for adopting the 95th percentile is to account for short-term volatility in spot prices, as price spikes tend to occur with little or no notice.

EER also suggested we publish the modelling data to improve transparency. In addition to the supporting information provided in this appendix, we have published relevant modelling data on our website to inform stakeholders' assessments and understanding of our methodology for estimating wholesale energy costs.[27]

[26] EER, sub. 5, p 7.
[27] QCA, *Regulated electricity prices for regional Queensland 2023–24*, QCA website, 2023.

Part B: Other energy costs

This section provides further detail to that contained in the main report, including why we consider ACIL's approach and other energy cost estimates are appropriate.

Other energy costs (total) are lower this year

The draft estimates of other energy costs show an overall decrease in other energy costs for both small customer tariffs (9.4 per cent, or $2.07/MWh) and large customer tariffs (13.3 percent, or $2.86/MWh):

- LRET[28] costs will increase by around 44 per cent ($2.19/MWh)—driven by an increase in the forward prices of large-scale generation certificates (LGCs) (using information from the Clean Energy Regulator (CER) and LGC forward prices[29])
- SRES[30] costs will decrease by around 37 per cent ($4.04/MWh)—driven by a decline in the number of small-scale technology certificates (STCs) retailers are required to purchase (using information published by CER[31])
- NEM management fees will increase by around 2 per cent ($0.02/MWh)—reflecting an increase in costs related to operating the NEM (using AEMO data, including recent historical fees and draft budgeted percentage changes for 2023–24[32])
- ancillary services charges will decline by approximately 58 per cent ($0.82/MWh)—due to lower costs for frequency control ancillary services (FCAS)[33] in Queensland. The completion of upgrades for the Queensland to New South Wales interconnector in July 2022 contributed to lower FCAS; thereby, ancillary costs returned to more normal levels (using information published by AEMO)
- prudential costs for small customers will increase by about 27 per cent ($0.69/MWh)—reflecting elevated contract prices and greater expected price volatility in the NEM (using latest published AEMO prudential requirements and ASX margin requirements)
- prudential costs for large customers will decrease by approximately 5 per cent ($0.10/MWh)—primarily due to changes in the shape of the relevant demand profile with more electricity consumed during the non-peak period, instead of during the peak period (using the latest published AEMO prudential requirements and ASX margin requirements)
- RERT costs will decline by approximately 99 per cent ($1.00/MWh)—driven by fewer activations of the RERT to assist with power system management.[34] This estimate excludes RERT activations during market events in June 2022 (using information published by AEMO)

[28] The LRET sets annual targets for the amount of electricity that must be sourced from large-scale renewable energy projects, such as utility-scale wind and solar generation. Retailers must purchase and surrender LGCs to the CER to fulfil their obligations under the LRET. For more information, see http://www.cleanenergyregulator.gov.au.
[29] Section 4.3.1 of ACIL's report.
[30] The SRES provides an incentive for individuals and small businesses to install eligible small-scale renewable energy systems. Retailers must purchase and surrender STCs to the CER to fulfil their obligations under the SRES. For more information, see http://www.cleanenergyregulator.gov.au.
[31] Section 4.3.2 of ACIL's report.
[32] AEMO, *2022–23 AEMO Budget and Fees*, June 2022.
[33] FCAS is a process used by AEMO to maintain the frequency of the electricity system within the normal operating band around 50 cycles per second.
[34] On 5 July 2022, AEMO activated the RERT in response to a forecast Lack of Reserve 2 (LOR 2) condition. A LOR 2 condition signals a tightening of electricity supply reserves. This condition exists when reserve levels are less than the single largest generator in a NEM region.

- costs associated with market events in June 2022 to be $0.89/MWh—these include the RERT and compensation costs determined and published by AEMO and AEMC to date (discussed further below)
- costs associated with energy losses are based on last year's loss factors. These will be updated as part of the final determination (using information on the latest transmission and distribution loss factors published by AEMO).

Sometimes retailers also incur costs associated with the Retailer Reliability Obligation (RRO).[35] However, at this stage, for 2023–24, the RRO has not been triggered for Queensland. Therefore, no RRO costs have been incurred.

ACIL's approach and estimates

We consider ACIL's approach to estimating the other energy costs is appropriate, as it reflects how retailers are likely to incur these costs in practice. It uses the latest information from relevant sources to estimate the relevant other energy costs (as described above). This includes information published by AEMO (on projected NEM fees for instance) and information published by the CER (reflecting the LRET/SRES obligations that retailers are expected to face in 2023–24).

Addressing stakeholder submissions

Consistent with EER's views, we have incorporated the costs to date associated with the June 2022 market events. A series of conditions affecting the NEM led to the triggering of the administered price cap[36], suspension of the spot market, and around 500 market interventions from 12 to 24 June 2022. In accordance with the National Electricity Rules (NER), certain costs associated with these events are passed on to retailers.

In total, the costs were estimated at $44,730,000 for Queensland.[37] This included costs associated with the RERT, direction costs and compensation relating to the administered pricing and NEM suspension.[38] This equates to $0.89/MWh, which is calculated by dividing these costs by Queensland's total energy requirements.

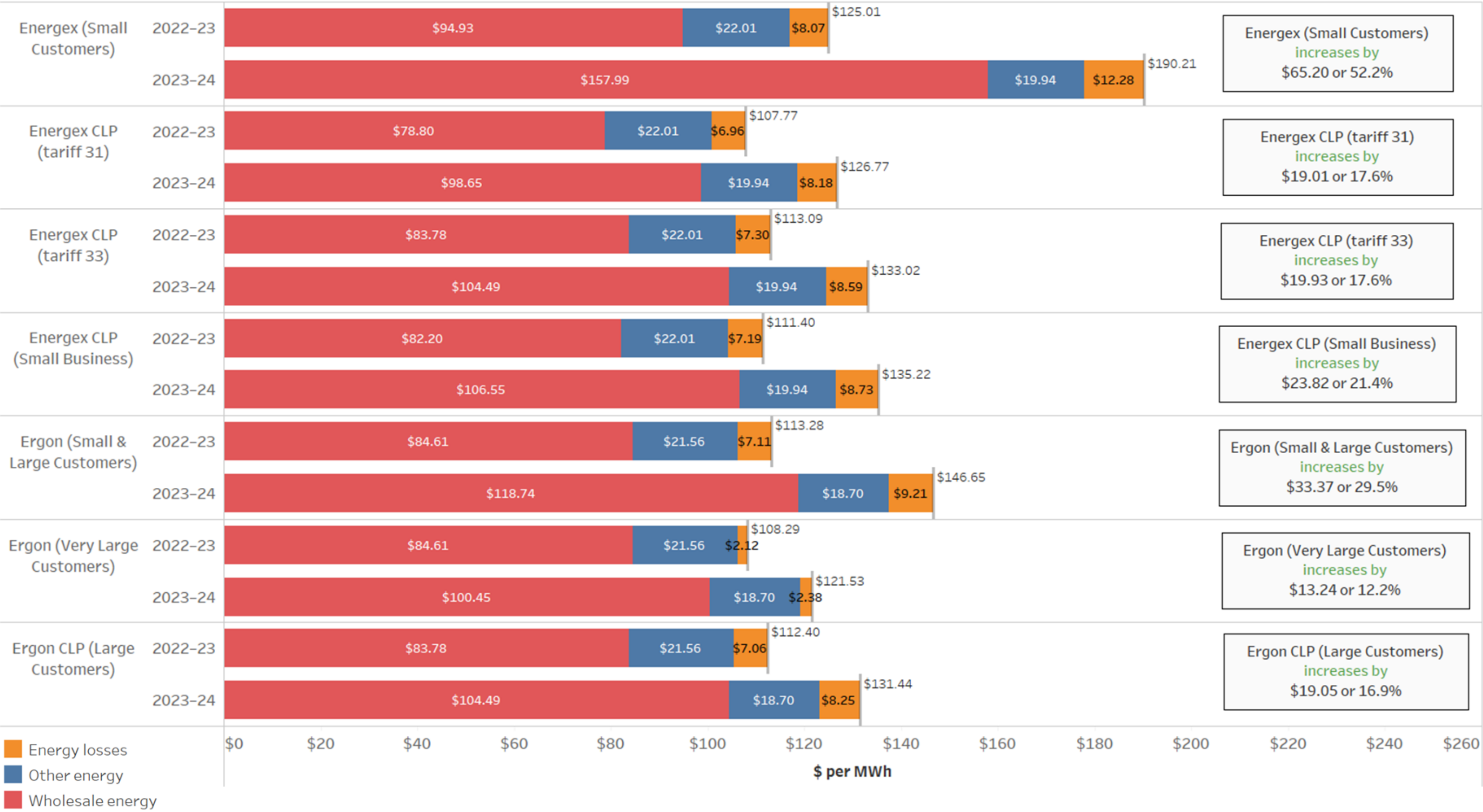
We will update our cost estimates for the final determination if more up-to-date information is published by the AEMC and AEMO.[39]

[35] When the RRO is triggered for a given quarter and NEM region, retailers are required to secure sufficient qualifying contracts to cover their share of the one-in-two-year peak demand.
[36] The administered price cap is essentially a last-resort safety-net price that aims to stabilise the electricity market by capping prices in the NEM following a prolonged period of extreme prices. It is designed to limit market participants' spot price exposure and, at the same time, provide sufficient revenue for generators to cover their short-term costs and continue supplying electricity through normal market mechanisms.
[37] AEMO, *June 2022 NEM Events: Compensation Update (6 January 2023)*, January 2023.
[38] See Table 4.15 of ACIL's report, which itemises the cost of the June 2022 market events by category. Note, this uses the AEMO published amounts from 6 January 2023, consistent with EER's views.
[39] Consistent with EER's views, if costs are still outstanding by the time of the final determination, we will assess the options available to address this. See EER, sub. 5, pp 8–9.

Changes in total energy cost allowances

The chart below summarises the changes in total energy cost allowances from 2022–23 to 2023–24.

Figure 1 Changes in total energy cost allowances



Note: Totals may not add up precisely due to rounding

APPENDIX C: COST PASS-THROUGH APPROACH

This appendix provides further information on how we calculated the small-scale renewable energy scheme (SRES) pass-through amounts included in the draft notified prices (discussed in section 5.2).

The approach we used involves the following two steps:

(1) Estimate the under- or over-recovery of SRES costs in 2022–23.

(2) Calculate SRES costs to be passed through in the 2023–24 notified prices.

Estimate the under- or over-recovery of SRES costs in 2022–23

First, we calculated the actual cost of SRES compliance during 2022–23, based on the Clean Energy Regulator's (CER's) final small-scale technology percentage (STP) for 2022 and 2023.

We then compared the actual cost of SRES compliance to the SRES allowance in the 2022–23 notified prices, which revealed an over-recovery of $2.19/MWh (0.2194 c/kWh) (Table 1).

Table 1 SRES over-recovery, 2022–23

Allowance vs actual costs	Period	STP		Clearing house price ($/MWh)[a]	SRES cost ($/MWh)	Average SRES cost ($/MWh)
		Final (%)	Non-binding (%)			
2022–23 final determination allowance	1 Jul – 31 Dec 2022	27.26%		40	10.904	10.904
	1 Jan – 30 Jun 2023		27.26%	40	10.904	
2022–23 actual cost	1 Jul – 31 Dec 2022	27.26%		40	10.904	8.710
	1 Jan – 30 Jun 2023	16.29%		40	6.516	
Over-recovery in 2022–23 (before adjusting for energy losses, the time value of money, variable retail cost allocators and the standing offer adjustment/headroom)						**2.194**

a Determined by the Clean Energy Regulator.

Calculated SRES costs to be passed through in the 2023–24 notified prices

We adjusted the over-recovery amounts (described above) for:

- energy losses (to determine the SRES liabilities based on energy acquired), by applying the relevant transmission and distribution loss factors adopted in the 2022–23 determination
- the time value of money (to restore the real value of the over-recovered amounts), by applying a nominal weighted-average cost of capital of 8.86%[40]
- the variable retail cost allocators and standing offer adjustment (consistent with the manner in which these allowances were applied as part of the 2022–23 determination).

Once adjusted, the resulting pass-through amount is included in the draft notified prices (Table 2).

[40] Based on our latest internal analysis.

Table 2 SRES pass-through amounts

Residential and load control[a] tariffs		
A	Negative allowance for SRES over-recovery in 2022–23 (c/kWh)	–0.2194
B	Energy losses in 2022–23 (total loss factor)	1.069
C	Discount rate (time value of money) (%)	8.86
D	Over-recovery before the application of standing offer adjustment and variable retail cost allowance (2023–24 c/kWh)	–0.2553
E	Variable retail cost allowance (residential) in 2022–23 (%)	7.25
F	Standing offer adjustment in 2022–23 (%)	3.7
G	SRES cost pass-through for 2023–24 (c/kWh)	–0.2840
Small business, load control[b] and unmetered supply tariffs		
A	Negative allowance for SRES over-recovery in 2022–23 (c/kWh)	–0.2194
B	Energy losses in 2022–23 (total loss factor)	1.069
C	Discount rate (time value of money) (%)	8.86
D	Over-recovery before the application of standing offer adjustment and variable retail cost allowance (2023–24 c/kWh)	–0.2553
E	Variable retail cost allowance (small business) in 2022–23 (%)	18.70
F	Standing offer adjustment in 2022–23 (%)	3.7
G	SRES cost pass-through for 2023–24 (c/kWh)	–0.3143
Limited access obsolete tariffs[c]		
A	Negative allowance for SRES over-recovery in 2022–23 (c/kWh)	–0.2194
B	Energy losses in 2022–23 (total loss factor)	1.067
C	Discount rate (time value of money) (%)	8.86
D	Over-recovery before the application of headroom and variable retail cost allowance (2023–24 c/kWh)	–0.2548
E	Variable retail cost allowance (small business) in 2022–23 (%)	18.70
F	Headroom allowance in 2022–23 (%)	0.0
G	SRES cost pass-through for 2023–24 (c/kWh)	–0.3025
Large business, load control[d], street lighting and obsolete[e] tariffs		
A	Negative allowance for SRES over-recovery in 2022–23 (c/kWh)	–0.2194
B	Energy losses in 2022–23 (total loss factor)	1.067
C	Discount rate (time value of money) (%)	8.86

D	Over-recovery before the application of headroom and variable retail cost allowance (2023–24 c/kWh)	–0.2548
E	Variable retail cost allowance (large business) in 2022–23 (%)	6.0445
F	Headroom allowance in 2022–23 (%)	0.0
G	SRES cost pass-through for 2023–24 (c/kWh)	–0.2702
Very large business tariffs		
A	Negative allowance for SRES over-recovery in 2022–23 (c/kWh)	–0.2194
B	Energy losses in 2022–23 (total loss factor)	1.020
C	Discount rate (time value of money) (%)	8.86
D	Over-recovery before the application of headroom and variable retail cost allowance (2023–24 c/kWh)	–0.2436
E	Variable retail cost allowance (very large business) in 2022–23 (%)	6.0445
F	Headroom allowance in 2022–23 (%)	0.0
G	SRES cost pass-through for 2023–24 (c/kWh)	–0.2583

a Tariffs 31 and 33.

b Tariff 34.

c Tariffs 62A, 65A and 66A.

d Tariffs 60A and 60B.

e Tariff 50.

Note: The SRES cost pass-through amounts were calculated using the formula: $G = A \times B \times (1 + C) \times (1 + E) \times (1 + F)$.

APPENDIX D: DATA USED TO ESTIMATE CUSTOMER IMPACTS

Typical customer figures are based on the annual consumption of the median customer on each tariff in regional Queensland. The median customer is the middle customer in terms of consumption out of all customers on each tariff. As such, half of all customers will use less electricity than the median customer, and half will use more.

Consistent with previous determinations, Ergon Retail has provided the latest actual usage data, gathered from its customer base of over 700,000 electricity customers in regional Queensland (Table 3).

Table 3 Median usage data used to determine customer impacts

Retail tariff	Usage (kWh per year)	Demand (kW per month)	Demand threshold (kW per month)
T11	4,468		
T31	1,616		
T33	1,513		
T20	4,891		
T44	153,019	59	30
T45	563,986	202	120
T46	297,823	411	400

APPENDIX E: BUILD-UP OF DRAFT NOTIFIED PRICES

Table 4 Draft notified prices—residential customers (excl. GST)

Retail tariff	Tariff component	Fixed[a]	Usage			Demand
			Off-peak/flat	Shoulder	Peak	
		c/day	c/kWh	c/kWh	c/kWh	$/kW/mth
Tariff 11—residential (flat-rate)	Network	55.000	7.874			
	Energy		19.021			
	Fixed retail	54.414				
	Variable retail		1.950			
	Standing offer adjustment	4.989	1.315			
	SRES cost pass-through		–0.2840			
	Total	**114.403**	**29.876**			
Tariff 12B—residential time-of-use	Network	53.400	2.880	3.532	16.518	
	Energy		19.021	19.021	19.021	
	Fixed retail	54.414				
	Variable retail		1.588	1.635	2.577	
	Standing offer adjustment	4.916	1.071	1.103	1.738	
	SRES cost pass-through		–0.2840	–0.2840	–0.2840	
	Total	**112.730**	**24.276**	**25.007**	**39.569**	
Tariff 12C—residential time-of-use	Network	53.400	2.880	3.532	16.518	
	Energy		5.981	12.369	33.486	
	Fixed retail	54.414				
	Variable retail		0.642	1.153	3.625	
	Standing offer adjustment	4.916	0.433	0.778	2.446	
	SRES cost pass-through		–0.2840	–0.2840	–0.2840	
	Total	**112.730**	**9.653**	**17.548**	**55.791**	
Tariff 14A—residential time-of-use demand	Network	53.400	3.277			4.300
	Energy		19.021			
	Fixed retail	54.414				
	Variable retail		1.617			0.312
	Standing offer adjustment	4.916	1.090			0.210
	SRES cost pass-through		–0.2840			
	Total	**112.730**	**24.721**			**4.822**
	Network	53.400	2.539			8.004

Retail tariff	Tariff component	Fixed[a]	Usage			Demand
			Off-peak/flat	Shoulder	Peak	
		c/day	c/kWh	c/kWh	c/kWh	$/kW/mth
Tariff 14B—residential time-of-use demand	Energy		19.021			
	Fixed retail	54.414				
	Variable retail		1.563			0.580
	Standing offer adjustment	4.916	1.054			0.391
	SRES cost pass-through		–0.2840			
	Total	**112.730**	**23.893**			**8.976**
Tariff 31—night rate (super economy)	Network		3.329			
	Energy		12.677			
	Fixed retail	3.366				
	Variable retail		1.160			
	Standing offer adjustment	0.153	0.783			
	SRES cost pass-through		–0.2840			
	Total	**3.519**	**17.666**			
Tariff 33—controlled (supply economy)	Network		4.249			
	Energy		13.302			
	Fixed retail	3.366				
	Variable retail		1.272			
	Standing offer adjustment	0.153	0.858			
	SRES cost pass-through		–0.2840			
	Total	**3.519**	**19.397**			

a Charged per metering point.
Note: Totals may not add due to rounding.

Table 5 Draft notified prices—small business and unmetered supply customers (excl. GST)

Retail tariff	Tariff component	Fixed[a]	Usage		Demand
			Off-peak/flat	Peak	
		c/day	c/kWh	c/kWh	$/kW/mth
Tariff 20—business (flat-rate)	Network	73.000	8.296		
	Energy		19.021		
	Fixed retail	69.074			
	Variable retail		5.108		
	Standing offer adjustment	6.479	1.479		
	SRES cost pass-through		–0.3143		
	Total	**148.553**	**33.589**		

Retail tariff	Tariff component	Fixed[a]	Usage		Demand
			Off-peak/flat	Peak	
		c/day	c/kWh	c/kWh	$/kW/mth
Tariff 24A—business (time-of-use demand)	Network	71.200	5.067		4.165
	Energy		19.021		
	Fixed retail	69.074			
	Variable retail		4.504		0.779
	Standing offer adjustment	6.396	1.304		0.225
	SRES cost pass-through		–0.3143		
	Total	**146.671**	**29.582**		**5.169**
Tariff 24B—business (time-of-use demand)	Network	71.200	4.175		9.326
	Energy		19.021		
	Fixed retail	69.074			
	Variable retail		4.338		1.744
	Standing offer adjustment	6.396	1.256		0.505
	SRES cost pass-through		–0.3143		
	Total	**146.671**	**28.475**		**11.575**
Tariff 34—business (interruptible supply)	Network	61.800	4.168		
	Energy		13.522		
	Fixed retail	69.074			
	Variable retail		3.308		
	Standing offer adjustment	5.968	0.957		
	SRES cost pass-through		–0.3143		
	Total	**136.842**	**21.641**		
Tariff 91—unmetered	Network		5.752		
	Energy		19.021		
	Fixed retail				
	Variable retail		4.632		
	Standing offer adjustment		1.341		
	SRES cost pass-through		–0.3143		
	Total		**30.432**		

a Charged per metering point.
Note: Totals may not add up precisely due to rounding.

Table 6 Draft notified prices—small business customers (excl. GST)

Retail tariff	Tariff component	Fixed band[a]					Usage		
		Band 1	Band 2	Band 3	Band 4	Band 5	Off-peak/flat	Shoulder	Peak
		c/day	c/day	c/day	c/day	c/day	c/kWh	c/kWh	c/kWh
Tariff 22B—small business time-of-use inclining band	Network	71.200	100.700	130.300	160.000	189.600	2.783	6.813	18.089
	Energy						19.021	19.021	19.021
	Fixed retail	69.074	69.074	69.074	69.074	69.074			
	Variable retail						4.077	4.831	6.940
	Standing offer adjustment	6.396	7.742	9.091	10.446	11.796	1.180	1.398	2.009
	SRES cost pass-through						–0.3143	–0.3143	–0.3143
	Total	**146.671**	**177.516**	**208.465**	**239.520**	**270.470**	**26.747**	**31.749**	**45.744**
Tariff 22C—small business time-of-use inclining band	Network	71.200	100.700	130.300	160.000	189.600	2.783	6.813	18.089
	Energy						5.981	12.369	33.486
	Fixed Retail	69.074	69.074	69.074	69.074	69.074			
	Variable Retail						1.639	3.587	9.645
	Standing offer adjustment	6.396	7.742	9.091	10.446	11.796	0.474	1.038	2.792
	SRES cost pass-through						–0.3143	–0.3143	–0.3143
	Total	**146.671**	**177.516**	**208.465**	**239.520**	**270.470**	**10.563**	**23.494**	**63.697**

a Charged per metering point.
Note: Totals may not add up precisely due to rounding.

Table 7 Draft notified prices—large business and street lighting customers (excl. GST)

Retail tariff	Tariff component	Fixed[a]	Usage		Demand			Excess demand
			Off-peak/flat	Peak	Off-peak/flat	Peak	Flat	
		c/day	c/kWh	c/kWh	$/kW/mth	$/kW/mth	$/kVA/mth	$/kVA/mth
Tariff 44—over 100 MWh small (demand)	Network	3848.500	2.327		24.592		22.132	
	Energy		14.665					
	Fixed retail	418.828						
	Variable retail		1.027		1.486		1.338	
	Headroom							
	SRES cost pass-through		–0.2702					
	Total	**4267.328**	**17.749**		**26.078**		**23.470**	
Tariff 45—over 100 MWh medium (demand)	Network	12523.700	2.327		24.592		22.132	
	Energy		14.665					
	Fixed retail	1152.083						
	Variable retail		1.027		1.486		1.338	
	Headroom							
	SRES cost pass-through		–0.2702					
	Total	**13675.783**	**17.749**		**26.078**		**23.470**	
Tariff 46—over 100 MWh large (demand)	Network	32654.400	2.327		19.585		17.819	
	Energy		14.665					
	Fixed retail	2930.897						
	Variable retail		1.027		1.184		1.077	
	Headroom							
	SRES cost pass-through		–0.2702					
	Total	**35585.297**	**17.749**		**20.769**		**18.896**	
Tariff 50A—large business time-of-use demand	Network	17158.000	2.370				15.516	3.103
	Energy		14.665					
	Fixed retail	377.178						
	Variable retail		1.030				0.938	0.188

Retail tariff	Tariff component	Fixed[a]	Usage		Demand			Excess demand
			Off-peak/flat	Peak	Off-peak/flat	Peak	Flat	
		c/day	c/kWh	c/kWh	$/kW/mth	$/kW/mth	$/kVA/mth	$/kVA/mth
	Headroom							
	SRES cost pass-through		–0.2702					
	Total	**17535.178**	**17.794**				**16.454**	**3.291**
Tariff 60A—large business flat-rate interruptible supply (primary)	Network	3848.500	7.572					
	Energy		13.144					
	Fixed retail	418.828						
	Variable retail		1.252					
	Headroom							
	SRES cost pass-through		–0.2702					
	Total	**4267.328**	**21.698**					
Tariff 60B—large business flat-rate interruptible supply (secondary)	Network		7.572					
	Energy		13.144					
	Fixed retail							
	Variable retail		1.252					
	Headroom							
	SRES cost pass-through		–0.2702					
	Total		**21.698**					
Tariff 71—street lighting	Network		10.541					
	Energy		14.665					
	Fixed retail							
	Variable retail		1.524					
	Headroom							
	SRES cost pass-through		–0.2702					
	Total		**26.459**					

a Charged per metering point.
Note: Totals may not add up precisely due to rounding.

Table 8 Draft notified prices—very large business customers (excl. GST)

Retail tariff	Tariff component	Fixed[a]	Usage	Connection unit	Capacity	Demand
		c/day	c/kWh	$/day/unit	$/kVA of AD/mth	$/kVA/mth
Tariff 51A—high voltage (CAC 66 kV)	Network	20532.100	1.347	6.911	3.398	3.647
	Energy		12.153			
	Fixed retail	2901.269				
	Variable retail		0.816	0.418	0.205	0.220
	Headroom					
	SRES cost pass-through		–0.2583			
	Total	**23433.369**	**14.058**	**7.329**	**3.603**	**3.867**
Tariff 51B—high voltage (CAC 33 kV)	Network	14243.300	1.347	6.911	4.127	3.778
	Energy		12.153			
	Fixed retail	2901.269				
	Variable retail		0.816	0.418	0.249	0.228
	Headroom					
	SRES cost pass-through		–0.2583			
	Total	**17144.569**	**14.058**	**7.329**	**4.376**	**4.006**
Tariff 51C—high voltage (CAC 22/11kV Bus)	Network	13154.000	1.347	6.911	4.742	4.581
	Energy		12.153			
	Fixed retail	2901.269				
	Variable retail		0.816	0.418	0.287	0.277
	Headroom					
	SRES cost pass-through		–0.2583			
	Total	**16055.269**	**14.058**	**7.329**	**5.029**	**4.858**
Tariff 51D— high voltage (CAC 22/11kV Line)	Network	12531.600	1.347	6.911	9.092	9.239
	Energy		12.153			
	Fixed retail	2901.269				
	Variable retail		0.816	0.418	0.550	0.558
	Headroom					

Retail tariff	Tariff component	Fixed[a]	Usage	Connection unit	Capacity	Demand
		c/day	c/kWh	$/day/unit	$/kVA of AD/mth	$/kVA/mth
	SRES cost pass-through		–0.2583			
	Total	**15432.869**	**14.058**	**7.329**	**9.642**	**9.797**
Tariff 53—high voltage (ICC)	Network	20532.100	1.347		3.398	3.647
	Energy		12.153			
	Fixed retail	2700.769				
	Variable retail		0.816		0.205	0.220
	Headroom					
	SRES cost pass-through		–0.2583			
	Total	**23232.869**	**14.058**		**3.603**	**3.867**
ICC site-specific—high voltage	Energy		12.153			
	Fixed retail	2700.769				
	Variable retail		0.816		0.205	0.220
	Headroom					
	SRES cost pass-through		–0.2583			
	Total	**2700.769**	**12.711**		**0.205**	**0.220**

a Charged per metering point.
Note: Totals may not add up precisely due to rounding.

Table 9 Draft notified prices—very large business customers (excl. GST)

Retail tariff	Tariff component	Fixed[a]	Usage		Connection unit	Capacity	Demand
			Off-peak	Peak			
		c/day	c/kWh	c/kWh	$/day/unit	$/kVA of AD/mth	$/kVA/mth
Tariff 52A—high voltage (CAC STOUD 33-66kV)	Network	9963.900	2.949	1.032	6.911	6.067	14.191
	Energy		12.153	12.153			
	Fixed retail	2901.269					
	Variable retail		0.913	0.797	0.418	0.367	0.858
	Headroom						
	SRES cost pass-through		–0.2583	–0.2583			
	Total	**12865.169**	**15.757**	**13.724**	**7.329**	**6.434**	**15.049**
Tariff 52B—high voltage (CAC STOUD 22/11kV Bus)	Network	9963.900	2.949	1.032	6.911	4.308	47.412
	Energy		12.153	12.153			
	Fixed retail	2901.269					
	Variable retail		0.913	0.797	0.418	0.260	2.866
	Headroom						
	SRES cost pass-through		–0.2583	–0.2583			
	Total	**12865.169**	**15.757**	**13.724**	**7.329**	**4.568**	**50.278**
Tariff 52C—high voltage (CAC STOUD 22/11kV Line)	Network	9963.900	2.949	1.032	6.911	7.826	68.575
	Energy		12.153	12.153			
	Fixed retail	2901.269					
	Variable retail		0.913	0.797	0.418	0.473	4.145
	Headroom						
	SRES cost pass-through		–0.2583	–0.2583			
	Total	**12865.169**	**15.757**	**13.724**	**7.329**	**8.299**	**72.720**

a Charged per metering point.
Note: Totals may not add up precisely due to rounding.

Table 10 Draft notified prices—large business customers (excl. GST)

Retail tariff	Tariff component	Fixed[a]	Usage[b]	
			Below threshold	Above threshold
		c/day	c/kWh	c/kWh
Tariff 43—Business customer (over 100 MWh)	Network	3848.500	2.857	10.891
	Energy		14.665	14.665
	Fixed retail	418.828		
	Variable retail		1.059	1.545
	Headroom			
	SRES cost pass-through		–0.2702	–0.2702
	Total	**4267.328**	**18.311**	**26.830**

a Charged per metering point.
b Usage (below threshold)—up to 97,000 kWh per year; usage (above threshold)— 97,000kWh per year and above.
Note: Totals may not add up precisely due to rounding.

Table 11 Draft limited-access obsolete tariffs—small business customers (excl. GST)

Retail tariff	Tariff component	Fixed[a]	Usage			Capacity	
			Block 1/ Peak	Block 2	Off-peak/flat	Up to 7.5 kW	Over 7.5 kW
		c/day	c/kWh	c/kWh	c/kWh	$/kW	$/kW
Tariff 62A—time-of-use declining block tariff[b]	Network	60.600	43.220	34.404	6.300		
	Energy		14.665	14.665	14.665		
	Fixed retail	51.819					
	Variable retail		10.824	9.176	3.920		
	Headroom						
	SRES cost pass-through		–0.3025	–0.3025	–0.3025		
	Total	**112.419**	**68.407**	**57.942**	**24.583**		
Tariff 65A—time-of-use tariff[c]	Network	60.300	31.524		11.120		
	Energy		14.665		14.665		
	Fixed retail	51.819					
	Variable retail		8.637		4.822		
	Headroom						
	SRES cost pass-through		–0.3025		–0.3025		
	Total	**112.119**	**54.524**		**30.304**		
Tariff 66A—dual-rate demand tariff	Network	192.300			9.864	3.816	11.521
	Energy				14.665		
	Fixed retail	51.819					
	Variable retail				4.587	0.714	2.154
	Headroom						
	SRES cost pass-through				–0.3025		
	Total	**244.119**			**28.813**	**4.530**	**13.675**

a Charged per metering point.
b Block 1—7 am to 9 pm on weekdays (first 10,000 kWh per month); Block 2—7 am to 9 pm on weekdays (remaining kWh per month); off-peak—all other times.
c Peak—a fixed 12-hour period as agreed between the retailer and customer from the range 7 am to 7 pm, 7.30 am to 7.30 pm or 8 am to 8 pm; off-peak—all other times.
Note: Totals may not add up precisely due to rounding.

Table 12 Draft obsolete tariffs—large business customers (excl. GST)

Retail tariff	Tariff component	Fixed[a]	Usage		Demand	
			Off-peak/flat	Peak	Off-peak/flat	Peak
		c/day	c/kWh	c/kWh	$/kW/mth	$/kW/mth
Tariff 50—over 100 MWh small (demand)	Network	3247.400	4.592	1.389	10.952	72.423
	Energy		14.665	14.665		
	Fixed retail	377.178				
	Variable retail		1.164	0.970	0.662	4.378
	Headroom					
	SRES cost pass-through		–0.2702	–0.2702		
	Total	**3624.578**	**20.151**	**16.754**	**11.614**	**76.801**

a Charged per metering point.
Note: Totals may not add up precisely due to rounding.

APPENDIX F: DRAFT GAZETTE NOTICE

Queensland Government Gazette

Electricity Act 1994

RETAIL ELECTRICITY PRICES FOR STANDARD CONTRACT CUSTOMERS

This Gazette notice replaces the Retail Electricity Prices for Standard Contract Customers notice dated 31~~11~~ May~~June~~ 202~~1~~2.

The notified prices are the prices decided under section 90(1) of the *Electricity Act 1994* (the Electricity Act).

A retailer must charge its Standard Contract Customers, as defined in the Electricity Act, the notified prices subject to the provisions of sections 91, 91A and 91AA of the Electricity Act and section 22A, Division 12A of Part 2 of the *National Energy Retail Law (Queensland)* (the NERL (Qld)).

Pursuant to the Certificates of Delegation from the Minister for Energy, Renewables and Hydrogen (dated 14~~16~~ December 202~~1~~2) and
sections 90 and 90AB of the Electricity Act, I hereby state that the Queensland Competition Authority decided that, on and from 1 July 2023~~2~~, the notified prices are the applicable prices set out in the attached Tariff Schedule.

As required by section 90AB(4) of the Electricity Act, the notified prices are exclusive of the goods and services tax ('GST') payable under the *A New Tax System (Goods and Services Tax) Act 1999* (Cth) (the GST Act).

Dated this DD~~31st~~ day of MM~~May~~ 202~~2~~3.

Flavio Menezes, Chair
Queensland Competition Authority

1

TARIFF SCHEDULE

Part 1 — Application

A) APPLICATION OF THIS SCHEDULE – GENERAL

This Tariff Schedule applies to all Standard Contract Customers in Queensland other than those in the Energex distribution area.

Definitions of customers and their types are those set out in the *Electricity Act 1994 (Queensland)* (the Electricity Act) and the *National Energy Retail Law (Queensland)* (the NERL (Qld)). Unless otherwise defined, the terminology used in this Tariff Schedule is intended to be consistent with the energy laws.

B) APPLICATION OF TARIFFS

General
Any reference to a tariff is a reference to a retail tariff in the Tariff Schedule unless otherwise explicitly stated in the Tariff Schedule.

Distribution entities may have specific eligibility criteria in addition to retail tariff eligibility requirements set out in the Tariff Schedule, e.g. the types of loads and how they are connected to interruptible supply tariffs. Retailers will advise customers of any applicable distribution entity requirements upon tariff assignment or customer request. However, retailers must not pass through to customers the default network tariff assignment criteria.

Additional customer descriptions:

- A *Connection Asset Customer (CAC)* is a large business customer whose installed capacity generally exceeds 1000 kVA and is connected to the distribution network at a minimum nominal voltage of 11 kV, but not exceeding a nominal voltage of 66 kV as classified by the distribution entity.
- An *Individually Calculated Customer (ICC)* is a large business customer whose installed capacity generally exceeds 10 MVA and is connected to the distribution network at a minimum nominal voltage of 33 kV, but not exceeding a nominal voltage of 132 kV as classified by the distribution entity. A customer taking supply at these voltages, but with installed capacity less than 10 MVA, may request to be classified as an ICC if it satisfies specific criteria set out in the distribution entity's approved Tariff Structure Statement.

CAC or ICC customers can only access tariffs where specifically stated in the tariff description.

Emergency is as defined in the *National Energy Retail Rules* as applied in Queensland.

The *QECMM (Queensland Electricity Connection and Metering Manual)* as required in the *Metrology Procedure: Part A, National Electricity Market*, or similar document setting out the minimum requirements for connection of supply to customer premises as intended by the QECMM.

MI means the unique identification number applicable to the point at which a premises is connected to a distribution entity's network. For premises connected to the National Electricity Market this is the National Metering Identifier (NMI), and for other premises is the unique identifier allocated by the distribution entity.

An *MI exclusive* tariff cannot be used in conjunction with any other continuous supply primary tariff at that MI. All large customer tariffs are MI exclusive tariffs unless otherwise stated.

A retailer must assign the applicable *default tariff* to a small customer in the event the small customer does not nominate a tariff when they become a Standard Contract Customer of the retailer except where any existing metering configuration at the MI is for a primary interruptible supply tariff, in which case the small customer must expressly nominate a suitable primary tariff. Such assignment does not alter a small customer's ability to access other tariffs in the event the small customer requests assignment to another tariff.

The default tariff is:

- For residential customers–Tariff 11
- For small business customers–Tariff 20.

A *primary* tariff is the tariff that reflects the principal purpose of use of electricity at the premises or the majority of the load, and is capable of existing by itself against a MI.

Small business customers can access primary residential tariffs providing the nature of all use on the tariff is consistent with the tariff requirements (refer below for *concessional application* of primary residential tariffs), and is in conjunction with a primary business tariff (Tariff 20~~, 22A~~, 22B, 22C, ~~24, ~~24A, 24B, 34~~, 41~~, 62A, 65A or 66A) at the same MI.

Primary residential tariffs are also applicable to electricity used in separately metered common sections of residential premises consisting of more than one living unit, but cannot be used in conjunction with another primary residential tariff at the same MI.

A *secondary* tariff is any tariff that is not a primary tariff, and can be accessed only when it is in conjunction with a primary tariff at the same MI.

A *seasonal* tariff is any tariff for which charges vary depending on the month the charge applies. Seasonal tariffs can also include time-of-use based charges.

A *time-of-use* tariff is any tariff for which charges vary depending on the time of day.

Any reference in this Tariff Schedule to a time is a reference to Australian Eastern Standard Time.

Weekdays mean Monday to Friday including public holidays.

Summer is the months of December to February inclusive.

A *daily supply charge* is a fixed amount charged to cover the costs of maintaining electricity supply to a premises, including the costs associated with the provision of equipment (for large customers, excluding metering and associated services) and general administration. Retailers may use different terms for this charge, for example: Service Charge, Service Fee, Service to Property Charge etc.

A connection charge reflects the value of the customer's dedicated connection assets and whether these assets were paid for upfront by the customer. The number of connection units allocated to an MI is as advised by the distribution entity.

Demand is the average rate of use of electricity over a 30-minute period as recorded in kilowatts (kW) on the associated metering, or as recorded or calculated in kilovoltamperes (kVA) using data recorded on the associated metering. No adjustment to import demand is made for export to the distribution network.

Maximum demand is the highest demand during the charging period of the particular tariff as identified by the tariff description. Unless otherwise stated, the maximum demand is the value on which demand charges are based.

For large customer tariffs in Part 2 listing charge parameter options in both kW and kVA, the applicable charging parameter is to be kVA except for:

- MI with type 6 metering – kW;
- MI where type 6 metering is replaced with type 1 to 4 metering due to fault, age, distributor initiated customer reclassification, or other action not initiated by the customer – kW or kVA at the customer's choice until the first anniversary of the type 6 meter replacement, and kVA from that time;
- MI with type 1 to 4 metering and the tariff assigned to that MI changes from an obsolete tariff to a standard tariff – kW or kVA at the customer's choice until the first anniversary of the tariff change, and kVA from that time.

Once a retailer applies the kVA demand charging parameter to an MI, a kW demand charging parameter can no longer be applied to the MI unless otherwise permitted by energy law.

A *demand threshold* is the demand value below which demand charges for a tariff do not apply for billing purposes. Where a demand threshold applies, the chargeable demand is the greater of the maximum demand less the demand threshold, or zero.

Authorised demand is the maximum demand permitted to be imported from, or exported to the network, and is specific to each MI. The value is generally established by agreement between the customer and distribution entity.

Excess demand for the billing period is the greater of the maximum demand outside the peak demand window minus the maximum demand during the peak demand window, or zero.

Capacity is a demand-based measure of the network supply capability reserved for a customer. Unless otherwise stated, the capacity charge is the greater of the authorised demand, or actual maximum demand.

Bus customers are those taking supply via direct connection to the distribution entity's zone substation or similar as advised by the distribution entity.

Line customers are those taking supply via direct connection to the distribution entity's high voltage electrical wires, cabling, or similar as advised by the distribution entity.

Continuous supply standard tariffs

Tariff 11

This tariff shall not apply in conjunction with any other primary residential tariff.

Tariff 20

This tariff shall not apply in conjunction with any other primary business tariff.

Tariffs 22B and 22C

The applicable daily supply charge for each customer's bill is determined by multiplying the customer's total average daily usage for all meter registers at the MI for the billing period by the number of days in the calendar year. Average daily usage is calculated on a pro rating basis having regard to the number of days in the billing period that supply was connected as expressly allowed or permitted by energy law. The applicable daily supply charge for the billing period is that which corresponds with the applicable annual usage Bands:

- Band 1 – up to 20,000 kWh/y
- Band 2 – 20,000 up to 40,000 kWh/y
- Band 3 – 40,000 up to 60,000 kWh/y
- Band 4 – 60,000 up to 80,000 kWh/y
- Band 5 – 80,000 kWh/y and above

Tariffs 14A and 24A

Customers choosing these tariffs should be aware that the underlying network tariffs may be subject to larger annual price changes compared to other network tariffs as distribution entities move them toward the network prices that underpin Tariffs 14B and 24B respectively. It is likely the network tariffs will then be extinguished. This process will likely impact future prices and access to Tariffs 14A and 24A.

Tariff 43

This tariff is only available to large business customers with basic metering (type 6) where that metering is not capable of measuring electricity usage under an alternative applicable standard tariff.

Interruptible supply standard tariffs

General

The retailer will arrange the provision of load control equipment on a similar basis to provision of the required revenue metering.

Where a customer's aggregate load that is connected to an interruptible supply tariff exceeds 20 amperes per phase, additional load control equipment must be installed in accordance with the QECMM. Such equipment must be installed at the customer's expense.

Availability of supply

Tariff 31

Supply will be available for a minimum of 8 hours per day for customers connected to the Ergon Energy network, and 5 hours per day for customers connected to the Essential Energy network, but may be reduced in an emergency. Times when supply is available is subject to variation at the absolute discretion of the distribution entity. In general, this supply will be between the hours of 10.00 pm and 7.00 am.

Tariff 33

Supply will be available for a minimum of 18 hours per day for customers connected to the Ergon Energy network, and 10 hours per day for customers connected to the Essential Energy network, but may be reduced in an emergency. Times when supply is available is subject to variation at the absolute discretion of the distribution entity.

Tariffs 34, 60A and 60B

These tariffs are not available to customers connected to the Essential Energy network within Queensland.

Supply will be available for a minimum of 18 hours per day for customers connected to the Ergon Energy network, but may be reduced in an emergency. Times when supply is available is subject to variation at the absolute discretion of the distribution entity.

Changes to connected load

Customers must notify their retailer of any change of more than 30 kW to the load connected to its interruptible supply tariff, including if the change is a reduction.

Other access requirements

~~*Tariff 33*~~

~~This tariff shall not apply in conjunction with Tariff 24.~~

Tariffs 34 and 60A

These tariffs shall not apply in conjunction with any other tariff.

Tariffs 60A and 60B

These tariffs are only available in areas where the distribution entity's standard load control signalling operates. Access to the tariffs may be subject to a network impact assessment by the distribution entity supporting customer access.

Electrical equipment connected to secondary interruptible supply tariffs

These tariffs are applicable where there is no provision to supply electrical equipment, or any specified part of electrical equipment, that is connected to a secondary interruptible supply tariff via another tariff (e.g. via a change-over switch to a continuous supply tariff), and electricity supply is:

(a) connected to electric vehicle supply equipment (residential customers only), or pool filtration or sanitation systems via a general purpose socket-outlet specifically labelled to indicate that it is connected to an interruptible supply tariff; or

(b) permanently connected to electric or heat pump storage water heaters, boost elements of solar water heaters, electric vehicle supply equipment, pool filtration or sanitation systems, pumping or irrigation equipment, battery energy storage systems, solar power systems, or other appliances (e.g. washing machines or dishwashers).

Where a part (e.g. a one-shot booster or circulating pump for a solar water heater) of electrical equipment connected to a secondary interruptible supply tariff is connected to another tariff, the part must be metered under and charged at the primary tariff of the premises concerned, or if more than one primary tariff exists, the tariff applicable to general power usage at the premises.

Unmetered supply standard tariffs

Tariff 71

Street lighting customers as defined in Queensland legislative instruments, are State or local government agencies for street lighting loads.

Street lights are deemed to illuminate the following types of roads:

- *Local government* controlled roads comprising land that is:
  (a) dedicated to public use as a road; or
  (b) developed for (or has as one of its main uses) the driving or riding of motor vehicles and is open to, or used by, the public; or
  (c) a footpath or bicycle path; or
  (d) a bridge, culvert, ford, tunnel or viaduct,

  and excludes State-controlled roads and public thoroughfare easements; and
- *State-controlled roads* declared as such under the *Transport Infrastructure Act 1994* (Qld).

All usage will be determined in accordance with the metrology procedure.

Tariff 91

This tariff is only available to customers with small loads other than street lights as set out in the distribution entity's Approved Unmetered Supply Devices list (or equivalent document), and applies where:

(a) the load pattern is predictable;

(b) for the purposes of settlements, the load pattern (including load and on/off time) can be reasonably calculated by a relevant method set out in the metrology procedure; and

(c) it would not be cost effective to meter the connection point taking into account:
  (i) the small magnitude of the load;
  (ii) the connection arrangements; and
  (iii) the geographical and physical location.

Charges are based on usage determined by the retailer.

Charges for installation, maintenance and removal of supply to an unmetered installation may apply in addition to the charge for electricity supplied. These charges are not regulated.

Individually Calculated Customers

As an alternative to Tariff 53 set out in Part 2 of this Schedule, Standard Contract Customers classed as ICC can choose to be supplied and billed by their retailer under the ICC site-specific tariff set out in Part 2 of this Schedule.

Obsolete tariffs

Limited-access obsolete tariffs

Small business customers can switch once to a *limited-access obsolete* tariff only if they have accessed the corresponding *discontinued* tariff as set out below at any time between 1 July 2017 and 30 June 2020:

Discontinued Tariff	Limited-access obsolete tariff
Tariff 62	Tariff 62A
Tariff 65	Tariff 65A
Tariff 66	Tariff 66A

Any subsequent tariff change by the customer must be to an applicable standard tariff, and the customer can no longer access a limited-access obsolete tariff.

Obsolete tariffs

Obsolete tariffs can only be accessed by customers who are on the tariff at the date it becomes obsolete and continuously take supply under it.

The *scheduled phase-out date* is the date an obsolete tariff will be discontinued.

Tariff 65A

The *daily pricing period* is a fixed 12-hour period as agreed between the retailer and the customer from the range 7.00am to 7.00pm; 7.30am to 7.30pm; or 8.00am to 8.00pm Monday to Sunday inclusive.

No alteration to the agreed daily pricing period is permitted until a period of twelve months has elapsed from the previous selection.

Tariff 66A

The fixed charge is determined by the larger of the connected motor capacity used for irrigation pumping, or 7.5 kW.

Any customer taking supply under this tariff who requests a temporary disconnection will not be reconnected unless an amount equivalent to the fixed charge that would have otherwise applied corresponding to the period of disconnection, has been paid.

Tariff changes

Discontinued or redesignated tariffs

Customers supplied under tariffs which have been discontinued or redesignated (whether by number, letter or name) on the date of the tariff being discontinued or redesignated, and whom have not notified their retailer of their preferred applicable standard tariff, will be transferred to an applicable standard tariff at the discretion of the retailer upon the tariff being discontinued or redesignated.

Seasonal time-of-use tariffs

Customers on seasonal time-of-use tariffs cannot change to another tariff less than one year from the application of the tariff to the customer's account unless expressly allowed or permitted by energy law.

Prorating of charges on bills

Where appropriate, charges on bills will be calculated on a pro rata basis having regard to the number of days in the billing cycle that supply was connected as expressly allowed or permitted by energy law. Retailers can advise customers of which charges on their bills are subject to prorating, and the methodology used.

Supply voltage

Tariffs can only be accessed by customers taking supply at *low voltage* as set out in the *Electricity Regulation 2006* unless specifically stated in the tariff description, or otherwise agreed with the retailer.

Metering

General

Revenue metering is metering used for billing purposes. Appropriate revenue metering must be in place for each tariff at a MI, unless otherwise permitted by energy law. Meter wiring and equipment to house meters is the customer's responsibility and must be installed and maintained at the customer's expense.

All data used for billing purposes will be determined in accordance with the metrology procedure unless otherwise permitted by energy law. The use of data substitutes or estimates is permissible, where in accordance with energy law.

The *metrology procedure* is the metrology procedure as issued by the Australian Energy Market Operator, and as added to by the *Electricity Distribution Network Code (Queensland)*.

A *type 4A* meter is a type 4 advanced digital meter which has the remote communications functions disabled.

Charges for customer metering services regulated by the Australian Energy Regulator and levied by the distribution entity are:

- for large customers–not included in notified prices. These will be applied to customers with metering other than types 1 to 4, in addition to the applicable notified prices contained in this Tariff Schedule.
- for small customers–are included in notified prices and cannot otherwise be charged to the customer.

~~If a retailer has received an upfront payment for supply and installation of metering at an MI, while the metering remains installed the retailer shall not charge the customer the capital charge set out in Part 4 of this Schedule, unless:~~

- ~~any replaced metering is type 5 or type 6; and~~
- ~~replacement is completed on a customer initiated request; and~~
- ~~the distribution entity as owner of the replaced meter continues to charge the retailer the capital charge for the replaced meter.~~

Card-operated meter customers

If a customer is an excluded customer (as defined in section 23 of the Electricity Act), the distribution entity may at its absolute discretion agree with the relevant local government authority on behalf of the customer, and the customer's retailer, that the electricity used by the customer is to be measured and charged by means of a card-operated meter.

If, immediately prior to 1 July 2007, electricity being used by a customer at premises is being measured and charged by means of a card-operated meter, the electricity used at the premises may continue to be measured or charged by means of a card-operated meter.

Residential customers with card-operated meters can access Tariff 11 as their primary tariff, and Tariffs 31 and 33 as secondary tariffs.

Small business customers with card-operated meters can access Tariff 20 as their primary tariff.

Charges will be those as set out in Part 2 for the particular tariff.

Other retail fees and charges

A retailer may charge its Standard Contract Customers the following:

(a) if, at a customer's request, the retailer provides historical billing data which is more than two years old:
– a maximum of **$30**

(b) retailer's administration fee for a dishonoured payment:
– a maximum of **$15**

(c) financial institution fee for a dishonoured payment:
– a maximum of **the fee incurred by the retailer**

(d) in addition to the applicable tariff, an additional amount in accordance with a program or scheme for the purchase of electricity from renewable or environmentally-friendly sources (whether or not that additional amount is calculated on the basis of the customer's electricity usage), but only if:
(i) the customer voluntarily participates in such program or scheme;
(ii) the additional amount is payable under the program or scheme; and
(iii) the retailer gives the customer prior written notice of any change to the additional amount payable under the program or scheme.

(e) if the customer refuses telecommunications and a type 4A meter is installed at the customer's explicit voluntary choice:
– a maximum of **$37.62 per meter read**

In the absence of a notified price, a retailer may charge a customer for the provision of distribution entity alternative control services at the prices regulated by the Australian Energy Regulator, or as otherwise modified by energy law, for those services on a cost pass through basis. These charges may be applied to a customer's bill in addition to the notified prices contained in this Tariff Schedule.

Concessional application

Tariff 11 is also available to customers where they satisfy the additional criteria set out in any one of **1**, **2** or **3**, below:

1. Separately metered installations where all electricity used is in connection with the provision of a Meals-on-Wheels service, or for the preparation and serving of meals to the needy and for no other purpose.

2. Residential institutions:

(a) where the total installation, or that part supplied and separately metered, must be domestic residential (i.e. it must include the electricity usage of the cooking, eating, sleeping and bathing areas which are associated with the residential usage). Medical facilities, e.g. an infirmary, which are part of the complex may be included; and

(b) that are:

  (i) a deductible gift recipient under section 30-227(2) of the *Income Tax Assessment Act 1997* to which donations of $2.00 and upwards are tax deductible; and

  (ii) a non-profit organisation that:

    A. imposes no scheduled charge on the residents for the services or accommodation that is provided (i.e. organisations that provide emergency accommodation facilities for the needy); or

    B. if scheduled charges are made for the services or accommodation provided, then all residents must be pensioners or, if not pensioners, persons eligible for subsidised care under the *Aged Care Act 1997* or the *National Health Act 1953*.

3. Organisations providing support and crisis accommodation which:

(a) have a service agreement for homelessness funding administered by the State; and

(b) are a deductible gift recipient under section 30-227(2) of the *Income Tax Assessment Act 1997* to which donations of $2.00 and upwards are tax deductible.

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Part 2—Standard tariffs

These tariffs are applicable subject to the matters set out in Part 1.

Small customer tariffs

Tariff	Description	Charge type	Rate	Unit
11	Residential flat-rate primary tariff	Usage	29.876	c/kWh
		Daily supply charge	114.403	c
12B	Residential time-of-use primary tariff	Usage:		
		Peak (4pm – 9pm)	39.569	c/kWh
		Day (9am – 4pm)	24.276	c/kWh
		Night (all other times)	25.007	c/kWh
		Daily supply charge	112.730	c
12C	Residential time-of-use primary tariff	Usage:		
		Peak (4pm – 9pm)	55.791	c/kWh
		Day (9am – 4pm)	9.653	c/kWh
		Night (all other times)	17.548	c/kWh
		Daily supply charge	112.730	c
14A	Residential time-of-use monthly demand primary tariff.	Demand:		
		Peak (4pm – 9pm)	4.822	$/kW
		All other times	0.0	$/kW
		Usage	24.721	c/kWh
		Daily supply charge	112.730	c
14B	Residential time-of-use monthly demand primary tariff.	Demand:		
		Peak (4pm – 9pm)	8.976	$/kW
		All other times	0.0	$/kW
		Usage	23.893	c/kWh
		Daily supply charge	112.730	c
20	Small business flat-rate primary tariff.	Usage	33.589	c/kWh
		Daily supply charge	148.553	c

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Tariff	Description	Charge type	Rate	Unit
22B	Small business time-of-use inclining-band primary tariff.	Usage:		
		Peak (4pm – 9pm weekdays)	45.744	c/kWh
		Day (9am – 4pm)	26.747	c/kWh
		Night (all other times)	31.749	c/kWh
		Daily supply charge:		
		Band 1	146.671	c
		Band 2	177.516	c
		Band 3	208.465	c
		Band 4	239.520	c
		Band 5	270.470	c
22C	Small business time-of-use inclining-band primary tariff.	Usage:		
		Peak (4pm – 9pm weekdays)	63.697	c/kWh
		Day (9am – 4pm)	10.563	c/kWh
		Night (all other times)	23.494	c/kWh
		Daily supply charge:		
		Band 1	146.671	c
		Band 2	177.516	c
		Band 3	208.465	c
		Band 4	239.520	c
		Band 5	270.470	c
24A	Small business time-of-use monthly demand primary tariff.	Demand:		
		Peak (4pm – 9pm weekdays)	5.169	$/kW
		All other times	0.0	$/kW
		Usage	29.582	c/kWh
		Daily supply charge	146.671	c
24B	Small business time-of-use monthly demand primary tariff.	Demand:		
		Peak (4pm – 9pm weekdays)	11.575	$/kW
		All other times	0.0	$/kW
		Usage	28.475	c/kWh
		Daily supply charge	146.671	c
31	Small customer flat-rate secondary tariff with interruptible supply.	Usage	17.666	c/kWh
		Daily supply charge	3.519	c
33	Small customer flat-rate secondary tariff with interruptible supply.	Usage	19.397	c/kWh
		Daily supply charge	3.519	c

Tariff	Description	Charge type	Rate	Unit
34	Small business flat-rate primary tariff with interruptible supply.	Usage	21.641	c/kWh
		Daily supply charge	136.842	c

Large customer tariffs

Tariff	Description	Charge type	Rate	Unit
43	Large business inclining-block primary tariff	Usage:		
		up to 97,000 kWh per year	18.311	c/kWh
		all remaining usage	26.830	c/kWh
		Daily supply charge	4267.328	c
44	Large business monthly demand primary tariff Demand threshold 30 kW / 35 kVA.	Chargeable demand; or	26.078	$/kW
		Chargeable demand	23.470	$/kVA
		Usage	17.749	c/kWh
		Daily supply charge	4267.328	c
45	Large business monthly demand primary tariff Demand threshold 120 kW / 135 kVA.	Chargeable demand; or	26.078	$/kW
		Chargeable demand	23.470	$/kVA
		Usage	17.749	c/kWh
		Daily supply charge	13675.783	c
46	Large business monthly demand primary tariff Demand threshold 400 kW / 450 kVA.	Chargeable demand; or	20.769	$/kW
		Chargeable demand	18.896	$/kVA
		Usage	17.749	c/kWh
		Daily supply charge	35585.297	c
50A	Large business time-of-use monthly demand primary tariff.	Demand:		
		Peak (4pm – 9pm weekdays)	16.454	$/kVA
		Excess	3.291	$/kVA
		Usage	17.794	c/kWh
		Daily supply charge	17535.178	c

Tariff	Description	Charge type	Rate	Unit
51A	Large business high-voltage monthly demand primary tariff only for customers classified as CAC and supplied at 66kV.	Demand	3.867	$/kVA
		Capacity	3.603	$/kVA
		Usage	14.058	c/kWh
		Daily connection charge	7.329	$/unit
		Daily supply charge	23433.369	c
51B	Large business high-voltage monthly demand primary tariff only for customers classified as CAC and supplied at 33kV.	Demand	4.006	$/kVA
		Capacity	4.376	$/kVA
		Usage	14.058	c/kWh
		Daily connection charge	7.329	$/unit
		Daily supply charge	17144.569	c
51C	Large business high-voltage monthly demand primary tariff only for customers classified as CAC and supplied on an 11 or 22kV bus.	Demand	4.858	$/kVA
		Capacity	5.029	$/kVA
		Usage	14.058	c/kWh
		Daily connection charge	7.329	$/unit
		Daily supply charge	16055.269	c
51D	Large business high-voltage monthly demand primary tariff only for customers classified as CAC and supplied on an 11 or 22kV line.	Demand	9.797	$/kVA
		Capacity	9.642	$/kVA
		Usage	14.058	c/kWh
		Daily connection charge	7.329	$/unit
		Daily supply charge	15432.869	c
52A	Large business high-voltage seasonal time-of-use monthly demand primary tariff only for customers classified as CAC and supplied at 33 or 66kV. Chargeable demand is the maximum demand between 10:00am and 8:00pm Summer weekdays. Chargeable capacity excludes all demands occurring during the chargeable demand periods.	Chargeable demand	15.049	$/kVA
		Chargeable capacity	6.434	$/kVA
		Usage – Summer	13.724	c/kWh
		Usage – All other times	15.757	c/kWh
		Daily connection charge	7.329	$/unit
		Daily supply charge	12865.169	c

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Tariff	Description	Charge type	Rate	Unit
52B	Large business high-voltage seasonal time-of-use monthly demand primary tariff only for customers classified as CAC and supplied on an 11 or 22kV bus. Chargeable demand is the maximum demand between 10:00am and 8:00pm Summer weekdays. Chargeable capacity excludes all demands occurring during the chargeable demand periods.	Chargeable demand	50.278	$/kVA
		Chargeable capacity	4.568	$/kVA
		Usage – Summer	13.724	c/kWh
		Usage – All other times	15.757	c/kWh
		Daily connection charge	7.329	$/unit
		Daily supply charge	12865.169	c
52C	Large business high-voltage seasonal time-of-use monthly demand primary tariff only for customers classified as CAC and supplied on an 11 or 22kV line. Chargeable demand is the maximum demand between 10:00am and 8:00pm Summer weekdays. Chargeable capacity excludes all demands occurring during the chargeable demand periods.	Chargeable demand	72.720	$/kVA
		Chargeable capacity	8.299	$/kVA
		Usage – Summer	13.724	c/kWh
		Usage – All other times	15.757	c/kWh
		Daily connection charge	7.329	$/unit
		Daily supply charge	12865.169	c
53	Large business high-voltage monthly primary tariff only for customers classified as ICC.	Demand	3.867	$/kVA
		Capacity	3.603	$/kVA
		Usage	14.058	c/kWh
		Daily supply charge	23232.869	c
ICC site-specific tariff	Large business high-voltage monthly primary tariff only for customers classified as ICC, where: • the AER approved site-specific network charges are passed-through to customers and • non-network components are chargeable as defined in Part 2 of this Schedule.	AER approved site-specific network charges	Network charges	-
		Demand	0.220	$/kVA
		Capacity	0.205	$/kVA
		Usage	12.711	c/kWh
		Daily supply charge	2700.769	c
60A	Large business flat-rate primary tariff with interruptible supply.	Usage	21.698	c/kWh
		Daily supply charge	4267.328	c
60B	Large business flat-rate secondary tariff with interruptible supply.	Usage	21.698	c/kWh

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Unmetered supply tariffs

Tariff	Description	Charge type	Rate	Unit
71	Business flat-rate primary tariff for street lighting.	Usage	26.459	c/kWh
91	Business flat-rate primary tariff.	Usage	30.432	c/kWh

Part 3—Obsolete tariffs

These tariffs are applicable subject to the matters set out in Part 1.

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Tariff	Description	Charge type	*Rate*	Unit
~~12A~~	~~Obsolete residential seasonal time-of-use primary tariff~~ ~~Scheduled phase-out date: 30 June 2023~~	~~Usage – Peak (Summer 3pm-9:30pm)~~	~~55.287~~	~~c/kWh~~
		~~Usage – All other times~~	~~19.736~~	~~c/kWh~~
		~~Daily supply charge~~	~~72.051~~	~~c~~
~~14~~	~~Obsolete residential seasonal time-of-use monthly demand primary tariff.~~ ~~*Peak daily demand* is the average of the 13 half-hourly demand recordings for each day from 3:00pm to 9:30pm during Summer.~~ ~~*Off-peak daily demand* is the average of the 13 half-hourly demand recordings for each day from 3:00pm to 9:30pm during all other times.~~ ~~*Peak chargeable demand* is the average of the four highest peak daily demands in the month.~~ ~~*Off-peak chargeable demand* is the greater of the average of the four highest off-peak daily demands in the month, or 3kW.~~ ~~Scheduled phase-out date: 30 June 2023~~	~~Chargeable demand – Peak~~	~~49.821~~	~~$/kW~~
		~~Chargeable Demand – Off peak~~	~~7.155~~	~~$/kW~~
		~~Usage~~	~~16.308~~	~~c/kWh~~
		~~Daily supply charge~~	~~44.127~~	~~c~~
~~22A~~	~~Obsolete small business seasonal time-of-use primary tariff.~~ ~~Scheduled phase-out date: 30 June 2023~~	~~Usage – Peak (Summer 10am-8pm weekdays)~~	~~58.907~~	~~c/kWh~~
		~~Usage – All other times~~	~~24.476~~	~~c/kWh~~
		~~Daily supply charge~~	~~113.298~~	~~c~~

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Tariff	Description	Charge type	*Rate*	Unit
~~24~~	~~Obsolete small business seasonal time-of-use monthly demand primary tariff.~~ ~~*Peak daily demand* is the average of the 20 half-hourly demand recordings for each weekday from 10:00am to 8:00pm during Summer.~~ ~~*Off peak daily demand* is the average of the 20 half-hourly demand recordings for each weekday from 10:00am to 8:00pm during all other times.~~ ~~*Peak chargeable demand* is the average of the four highest peak daily demands in the month.~~ ~~*Off peak chargeable demand* is the greater of the average of the four highest off-peak daily demands in the month, or 3kW.~~ ~~Scheduled phase-out date: 30 June 2023~~	~~Chargeable demand – Peak~~ ~~Chargeable Demand – Off peak~~ ~~Usage~~ ~~Daily supply charge~~	~~74.985~~ ~~7.535~~ ~~18.868~~ ~~59.315~~	~~$/kW~~ ~~$/kW~~ ~~c/kWh~~ ~~c~~
~~41~~	~~Obsolete small business monthly demand primary tariff.~~ ~~Scheduled phase-out date: 30 June 2023~~	~~Demand~~ ~~Usage~~ ~~Daily supply charge~~	~~19.307~~ ~~16.531~~ ~~609.389~~	~~$/kW~~ ~~c/kWh~~ ~~c~~
50	Obsolete large business seasonal time-of-use monthly demand primary tariff. Peak is Summer, being 10:00am to 8:00pm on Summer weekdays for determining chargeable demand, and all day each day for usage. Off-peak is all times in non-summer months for determining chargeable demand and usage. Peak demand threshold 20 kW. Off peak demand threshold 40 kW. Scheduled phase-out date: To be confirmed	Peak chargeable demand Off-peak chargeable demand Peak usage Off-peak usage Daily supply charge	76.801 11.614 16.754 20.151 3624.578	$/kW $/kW c/kWh c/kWh c
62A	Limited-access obsolete small business time-of-use declining-block primary tariff. Scheduled phase-out date: To be confirmed	Usage – 7am to 9pm weekdays: first 10,000 kWh/month remaining Usage – all other times Daily supply charge	 68.407 57.942 24.583 112.419	 c/kWh c/kWh c/kWh c

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Tariff	Description	Charge type	*Rate*	Unit
65A	Limited-access obsolete small business time-of-use primary tariff. Scheduled phase-out date: To be confirmed	Usage – Peak (daily pricing period)	54.524	c/kWh
		Usage – all other times	30.304	c/kWh
		Daily supply charge	112.119	c
66A	Limited-access obsolete small business fixed dual-rate demand primary tariff. Scheduled phase-out date: To be confirmed	Fixed charge (monthly) – first 7.5kW	4.530	$/kW
		Fixed charge (monthly) – remaining kW	13.675	$/kW
		Usage	28.813	c/kWh
		Daily supply charge	244.119	c

Part 4—Metering service charges

These charges are applicable subject to the matters set out in Part 1.

Large customer—type 1, 2, 3, 4 (advanced digital) meters

Description	Charge type	Rate	Unit
Standard asset customer (annual consumption 750MWh or less)	Daily metering charge	216.940	c
Standard asset customer (annual consumption greater than 750MWh)	Daily metering charge	260.421	c
Connection asset customer	Daily metering charge	429.295	c
Individually calculated customer	Daily metering charge	375.281	c

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~~**Small customer—type 1, 2, 3, 4 (advanced digital) meters**~~

~~Description~~	~~Charge type~~	~~Rate~~	~~Unit~~
~~Primary tariff~~	~~Daily capital charge~~	~~7.353~~	~~c~~
	~~Daily non-capital charge~~	~~3.447~~	~~c~~
~~Secondary tariff (per tariff)~~	~~Daily capital charge~~	~~2.123~~	~~c~~
	~~Daily non-capital charge~~	~~1.025~~	~~c~~

End of Tariff Schedule

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