Queensland Competition Authority

Technical appendices

Regulated retail electricity prices in regional Queensland 2022–23

May 2022

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STRUCTURE OF THE TECHNICAL APPENDICES

The technical appendices aim to provide stakeholders with detailed information relevant to setting notified prices this year and should be read in conjunction with the main report.

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APPENDIX A: MINISTER'S DELEGATION

Queensland Government

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

Our Ref: MN07763-2021

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Brisbane Queensland
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16 DEC 2021

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) my functions under section 90(1) of the Act for the determination of regulated retail electricity prices in regional Queensland for 2022-23.

The Queensland Government is committed to delivering affordable electricity for households and businesses which is fundamental to driving economic recovery in regional Queensland, especially given the ongoing COVID-19 pandemic.

I note the State-wide rollout and integration of electric vehicles (EVs) into Queensland will be an area of key focus in the upcoming 10-year Energy Plan and the Zero Emissions Vehicle Strategy. Pricing, infrastructure, network impacts and access to EVs will be considered as part of these strategies.

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 Queensland wants to encourage this uptake in a sustainable way that limits adverse impacts on the system.

There is much uncertainty around technology costs, consumer preferences and the ability to positively manage the impacts of EVs on the system. Electricity tariffs are being deployed worldwide seeking to encourage the shift of load from peak periods to those of low demand. In Queensland, with the impressive uptake of solar power systems at both household and utility scale, demand is now consistently low during daylight hours. Modelling by the Australian Energy Market Operator suggests that if left unchecked this may present challenges to the reliability of our electricity network over the medium term.

With the introduction of Tariff 12B from 1 January 2021, regional Queensland is setting the pace in encouraging greater use of our abundant renewable energy. This new 'solar-soaker' tariff flips the old way of thinking about electricity prices with the cheapest rate of just 16.13 cents per kilowatt-hour (c/kWh) being available from 9:00am to 4:00pm. I am advised Tariff 12B has a cheap daytime off-peak network component of 4.24 c/kWh, however the energy cost component is flat across all time periods and does not reflect actual underlying energy cost structures that vary across the day. While this tariff will be reviewed under this delegation in a standard manner, I will also look to a new time-of-use tariff with improved price signals and I intend to provide a separate delegation in early 2022.

The Department of Energy and Public Works (the department) is already working with the QCA and other stakeholders on a new direction for tariffs that would inform and reflect this new approach. Vehicle to grid capability is also expected to further change how EVs and batteries interact with the network with two-way flows of electricity becoming more common. These represent valuable consumer-owned sources of flexible demand and supply.

As part of the price determination process, I would greatly appreciate QCA considering how tariffs could be structured to better guide customer behaviour. This will be critical in encouraging the charging of EVs in periods of low network demand and high renewable energy generation. It is important to manage costs to customers and minimise the need for new electricity infrastructure to cope with the switch from petroleum fuels to electricity as Queensland's EV fleet grows. The QCA may include commentaries about the need for new retail tariffs with different structures to those currently available and also incentives for customers to respond to stronger pricing signals within tariffs. This advice will inform a separate delegation for new tariffs suitable for EV customers which I intend to issue to the QCA in early 2022.

The 10-year Energy Plan and the Zero Emissions Vehicle Strategy will assist in setting direction for key stakeholders through to 2030. The department will work closely with its electricity distributors to ensure the right mix of network tariffs are in place, building the platforms from which regulated retail tariffs will be developed for regional Queensland, and market driven retail products developed for South East Queensland (SEQ).

Realising a future that benefits all electricity users hinges on providing effective motivations, rewards and incentives for customers to move their electricity consumption. Solar-soaker and time-of-use tariffs are critical policy levers that can be used to support integrating a range of technologies like EVs, batteries, solar power and home energy management systems into Queensland's electricity network.

The enclosed delegation and terms of reference for 2022-23 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 DMO process is currently under review at the national level, I consider it appropriate that QCA conduct its usual process to determine all the associated costs that contribute to notified prices under the Queensland Government's long standing UTP. For small customers, this also means considering all costs and benefits associated with standing offers in SEQ.

Customers and stakeholders in regional Queensland have a long-standing preference for simplicity and choice with regards to electricity pricing. However, it is important that the Tariff Schedule reflect and provide appropriate and meaningful tariff options for customers, relative to their tariff class. As such, I ask QCA to consider reviewing the existing tariff offers with a view to rationalising them as it considers appropriate as part its 2022-23 price setting process.

QCA should consider if individual tariffs are meeting customer needs, and balance competing factors including the impact extinguishing a tariff would have on customers and their options, along with other matters QCA considers relevant. Consistent with application of UTP, this should be informed by the price structures commonly available in the deregulated SEQ electricity market and with a view to future needs for a variety of tariffs to be available as customer preferences, needs and technologies change.

I consider it necessary to retain at a minimum the existing flat-rate and controlled load tariffs for both residential and small business customers, and careful consideration should be given to retaining any tariffs compatible with the future wide-spread uptake of EVs and other technologies. In the event any tariff is to be extinguished, QCA should consider setting a suitable phase-out period that affords affected customers reasonable time to assess their remaining tariff options and to choose the most suitable ongoing standard tariff for their circumstances.

Another important policy consideration relates to the equitable pricing of metering services for customers. Consistent with the 2021-22 financial year, I ask QCA to consider and set the charges that apply to the provision of advanced digital metering services.

Public consultation has long formed a vital part of QCA's process for determining retail electricity prices. The terms of reference set out the consultation needs and requires QCA to publish its draft determination in February 2022 and its final determination by 31 May 2022.

To ensure regional customers continue to benefit from the electricity cost protection provided by UTP, and the benefits of owing our own assets, the department will be available to consult with QCA on the 2022-23 price determination and Tariff Schedule.

If you have any questions, [redacted] Executive Director, Energy Division, Department of Energy and Public Works, can be contacted on [redacted] or by email [redacted]

Yours sincerely

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

Encl: Section 90AA Delegation and Terms of Reference

DELEGATION TO QCA

DEPARTMENT OF ENERGY AND PUBLIC WORKS

Electricity Act 1994

ELECTRICITY (MINISTERIAL) DELEGATION (NO. 1) 2021 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.

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 2022 to 30 June 2023.

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 2022–23 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: 16/12/2021

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 2022 to 30 June 2023.

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) Reviewing existing available tariffs with a view to rationalising and extinguishing any tariffs no longer considered appropriate, including the introduction of suitable transition arrangements for any impacted customers, if required;

   (c) 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;

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

      (i) For residential and small business customer Tariffs 11 and 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 residential and small business customer Tariffs 12A, 14, 22A and 24, use of a price indexation methodology applied to the N component used in the 2020–21 price determination on the basis that these tariffs no longer have an underlying network tariff;

      (iii) For all other residential and small business customer tariffs, except for those set out in d(iv) 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;

(iv) 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';

(e) For all retained Standard tariffs as set out in Part 2 of the current Tariff Schedule – maintaining these tariffs including price structures and access criteria unless otherwise set out in this delegation;

(f) Setting small customer advanced digital metering service charges at the Energex rate for standard Type 6 small customer metering services;

(g) 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;

(h) 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 workshops that the QCA considers would assist the consultation process.

Workshops 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 (workshops 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 2022–23 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 2022.

15. The QCA must publish the final price determination on regulated retail electricity tariffs for the 2022–23 tariff year and have the retail tariffs gazetted no later than 31 May 2022.

(SCHEDULE ENDS)

APPENDIX B: STAKEHOLDER SUBMISSIONS AND REFERENCES

Stakeholder submissions

The submissions we received from stakeholders during this review are listed below. They are available on our website.[1]

Stakeholder	*Submission number*	*Date received (2022)*
Bundaberg Regional Irrigators Group (BRIG)	1	19 January
Canegrowers	2	19 January
	8	6 April
Cotton Australia	3	19 January
	9	7 April
Ergon Energy and Energex Limited	4	19 January
Ergon Energy Queensland (EER)	5	19 January
	10	7 April
Etrog Consulting	16	20 April
National Irrigators' Council	12	6 April
Northern Iron & Brass Foundry	13	18 March
Pauli , V	14	26 February
Pioneer Valley Water Co-operative Ltd	6	19 January
Queensland Electricity Users Network (QEUN)	15	19 April
Queensland Farmers' Federation (QFF)	7	19 January
	11	7 April

The reference list appears on the next page.

[1] We received two confidential submissions, which are not published on our website.

References

ACIL Allen, *2020–21 regulated electricity price review: Updating retail costs*, final report, prepared for the QCA, May 2021.

—— *Estimated Energy Costs*, final report, prepared for the QCA, May 2022.

Australian Competition and Consumer Commission (ACCC), *Inquiry into the National Electricity Market—November 2021 report*, November 2021.

Australian Energy Market Commission (AEMC), *Review of the regulatory framework for metering services*, directions paper, September 2021.

Australian Energy Market Operator (AEMO), *2021–22 AEMO Budget and Fees*, 2021.

—— *2021 Electricity Statement of Opportunities*, August 2021.

—— *Draft FY23 Budget & Fees*, presentation to Finance Consultation Committee, April 2022.

—— *Quarterly Energy Dynamics Q1 2022*, April 2022.

—— *Estimate payments and volumes for Reliability and Emergency Reserve Trader (RERT) activation on 1 February 2022*, 7 February 2022.

—— *Update—Estimated intervention event payments for RERT activation on 1 February 2022*, 24 February 2022.

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Statement of Expectations of energy businesses: Protecting consumers and the market during COVID-19, 9 April 2020.

—— *Default market offer prices: Options paper on the methodology to be adopted for the 2022–23 determination (and subsequent years)*, October 2021.

—— *Default market offer prices 2022–23*, final determination, May 2022.

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—— *Energex Tariff Structure Statement 2020–2025*, June 2020 (erratum August 2020).

Energy Security Board, *Post 2025 Electricity Market Design*, ESB website, n.d., accessed 4 May 2022.

Ergon Energy Network and Energex, *Network Electric Vehicles Tactical Plan: Summary,* October 2020.

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Queensland Competition Authority (QCA), *Supplementary review: Regulated retail electricity prices for 2020–21*, final determination, October 2020.

—— *Regulated retail electricity prices for 2021–22: Regional Queensland*, final determination, June 2021.

—— *Regulated retail electricity prices for 2021–22: Regional Queensland, Technical appendices*, final determination, June 2021.

—— *SEQ retail electricity market monitoring 2020–21*, December 2021.

—— *Regulated retail electricity prices in regional Queensland 2022–23*, draft determination, February 2022.

—— *Regulated retail electricity prices in regional Queensland 2022–23*, technical appendices, February 2022.

Queensland Government, *Queensland Budget 2021–22, Budget Strategy and Outlook*, Budget Paper no. 2, June 2021.

Reserve Bank of Australia (RBA), *Statement on Monetary Policy—May 2022*, May 2022.

The University of Melbourne, *Electric Vehicle Uptake and Charging: A consumer-focused review*, April 2021.

APPENDIX C: ENERGY COST APPROACH

This appendix provides further detail on why we consider ACIL Allen's (ACIL's) estimates are appropriate. It includes estimates for each of the three energy cost components (as noted in section 4.2.1). It covers some of the more complex methods and assessments used in estimating energy costs. ACIL's final report, including the information we relied on to prepare this technical appendix, is available on our website.[2]

Wholesale energy costs

A retailer incurs wholesale energy costs when purchasing electricity from the National Electricity Market (NEM) and engaging in risk management strategies to meet the electricity requirements (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 $15,100 per megawatt hour (MWh).[3]

Retailers adopt a range of hedging strategies to manage spot price volatility (spot price risk), including:

- purchasing financial derivatives[4]—such as futures, swaps, caps and options
- entering long-term power purchase agreements (PPAs) with electricity generators
- investing in their own electricity generators (also known as vertical integration).

For this price determination, we engaged ACIL to assist us with estimating wholesale energy costs for customers whose prices are settled on:

- the net system load profiles (NSLPs) in the Energex and Ergon areas
- the controlled load profiles (CLPs) for the load control tariffs available to both residential and small business customers in the Energex area. There are currently two types of CLPs of this nature—CLP 9000 and CLP 9100—which capture the consumption profiles of south east Queensland customers on tariffs equivalent to retail tariffs 31 and 33 respectively
- the CLPs for the small business load control tariff in the Energex area (Energex CLP, small business)
- the CLPs for large business load control tariffs in the Ergon area (Ergon CLP, large business).

The NSLPs and CLPs approximate the timing and amount of electricity consumed by customers on accumulation meters in a region, for every half-hour of the day. Unlike smart/interval meters, accumulation meters do not record how much electricity was consumed at a particular point in time.

However, when retailers acquire electricity from the NEM, they pay the Australian Energy Market Operator (AEMO) for electricity based on spot prices and electricity demand that both fluctuate every 5 minutes. To address this settlement issue for customers on accumulation meters, AEMO uses the regional NSLPs and CLPs to estimate daily average spot prices[5]. Currently, most customers in Queensland are on accumulation meters. Consequently, we have used these demand profiles when estimating wholesale energy costs.

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[2] ACIL Allen, *Estimated Energy Costs*, final report prepared for the QCA, May 2022.

[3] 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.

[4] Generally, by purchasing financial derivatives, retailers can lock in a price, or a maximum price (in the case of caps), at which a given volume of electricity will be transacted at a future date.

[5] This average price is estimated by taking the average of daily spot prices weighted by the electricity demand. In other words, spot prices with higher demand contribute more to the average price.

Summary of analysis and findings

Consistent with previous years, we estimated wholesale energy costs using a market hedging approach designed to simulate the NEM from a retailer's perspective. A core feature of this approach is that it incorporates a hedging strategy that a prudent retailer would adopt to manage spot price risk in the NEM. More specifically, this involves:

- simulating the expected spot prices that a retailer faces, considering temperature-related demand profiles, generation supply and costs, as well as power station availability; and then
- estimating wholesale energy costs for a retailer that hedges spot price risk through the purchase of ASX Energy contracts[6].

Compared to estimates from last year, we estimated an increase in wholesale energy costs for all customers in 2022–23 whose prices are settled on the NSLPs and CLPs identified above (Figure 1). This primarily reflects a substantial increase in the trade-weighted ASX contract prices[7] for base and cap contracts.

The increase in ASX contract prices is driven by market participants expecting higher spot prices and greater price volatility, likely due to:

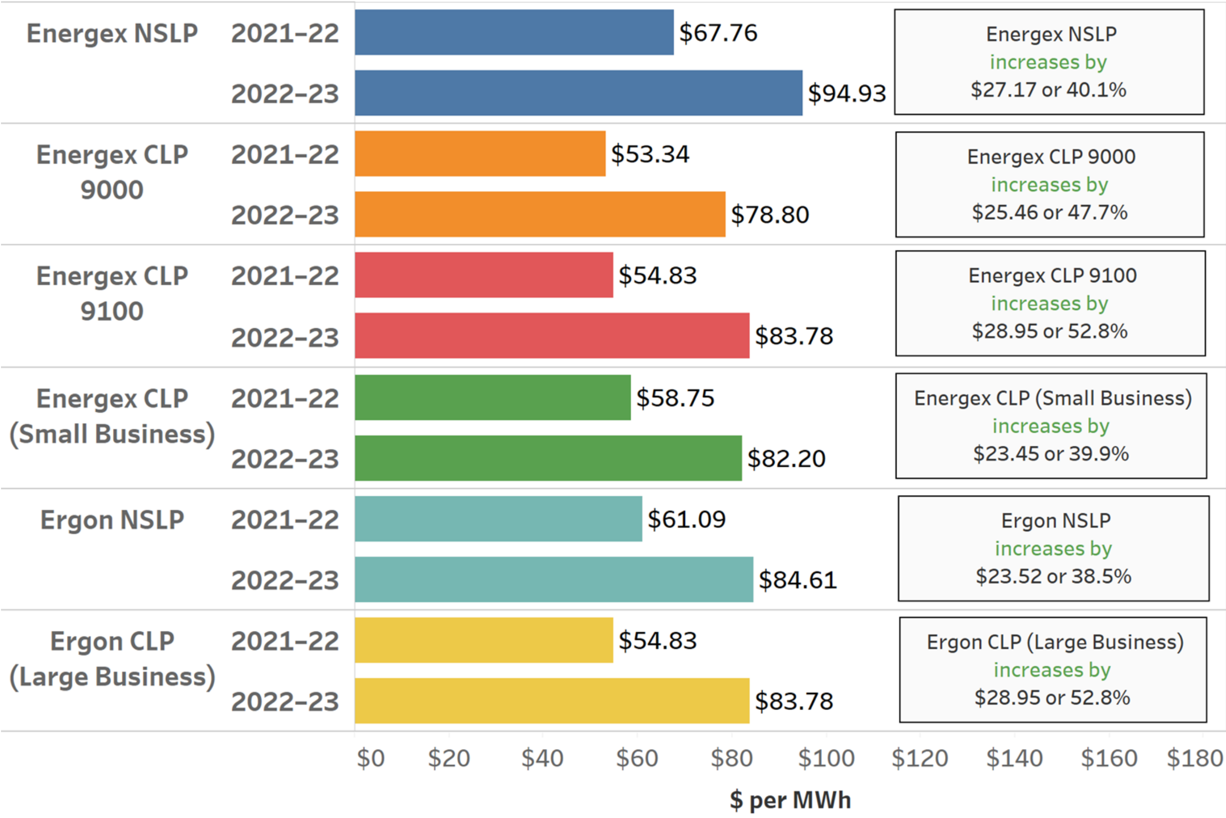
- a slowdown of renewable energy generators coming online (compared to recent years) and the reduced availability of thermal generators—both of which contribute to a tighter supply–demand balance in Queensland
- higher gas and coal prices—thermal generators are facing higher fuel costs due to prevailing high domestic gas prices to date and higher international commodity prices
- uncertainties faced by cap contract providers around the ability of their peaking plant[8] to cover price spikes in the NEM under a 5-minute settlement. For example, there have been concerns that existing peaking gas generators would be unable to ramp up their generation fast enough to respond to changes in the market when prices are settled on 5-minute intervals.

[6] ASX Energy contracts are exchange-traded energy financial derivatives that allow retailers to reduce the spot price volatility risk when purchasing electricity from the NEM. For more information, see https://www.asxenergy.com.au/.

[7] Contract prices were estimated using the trade-weighted average of ASX Energy daily settlement prices of base, peak and cap contracts for each of the four quarters of 2022–23.

[8] Peaking plants, such as open-cycle gas turbine plants, usually have higher operating costs but very fast start-up and shut-down times compared with coal-fired generators. These plants also can change outputs rapidly.

Figure 1 Wholesale energy costs by demand profiles



Source: QCA's analysis of data from ACIL Allen.

Demand considerations

To estimate wholesale energy costs, ACIL used its stochastic demand model to develop 51 weather-influenced simulations of hourly demand for the NSLPs, CLPs and the system-wide demand for Queensland. The simulated hourly demand was developed using:

- 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)
- AEMO's latest demand forecast for 2022–23, including energy forecasts of AEMO's central scenario and the seasonal peak demands with a 10% probability of exceedance (POE)[9], 50% POE and 90% POE.[10]

The weather-influenced system-wide hourly demand (i.e. the demand satisfied by scheduled and semi-scheduled generation[11]) was then used to simulate the expected spot prices, while the simulated NSLPs and CLPs were required to develop separate wholesale energy estimates for each profile.

[9] 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).

[10] AEMO, *2021 Electricity Statement of Opportunities*, August 2021.

[11] 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 hydro power 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.

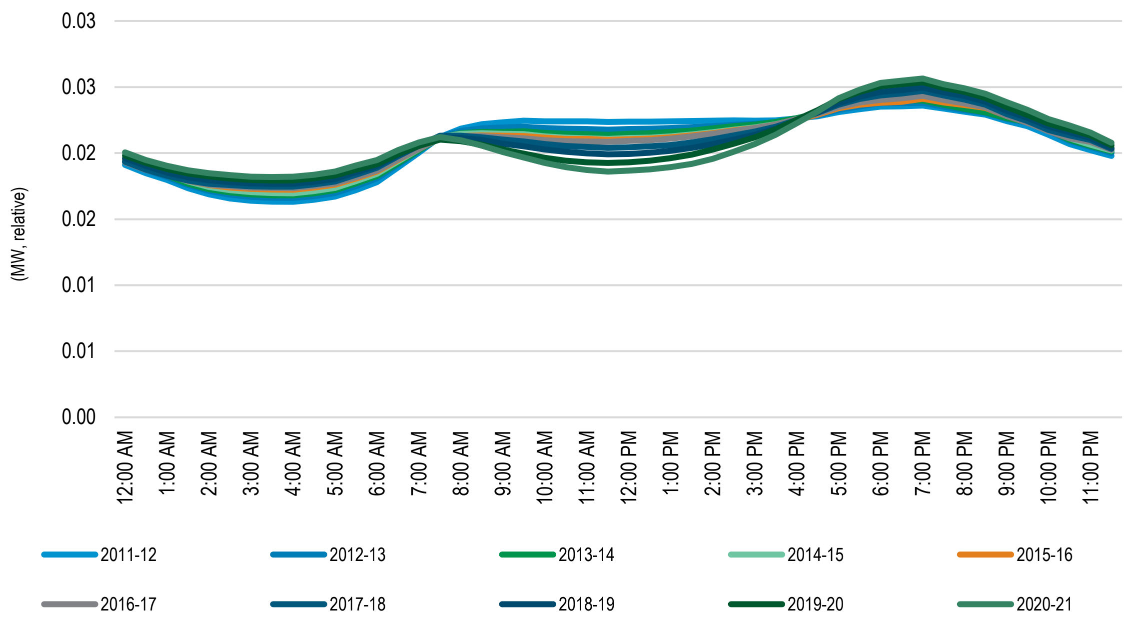
The historical demand profiles were sourced from AEMO's Market Management System (MMS) and Market Settlement and Transfer Solutions (MSATS). However, for the newly introduced tariffs with limited historical profiles (i.e. the load control tariffs for small and large business customers), ACIL used the relevant representative demand profiles that we recently developed using data from Energy Queensland.

The demand profile for the small business load control tariff was derived using Energy Queensland's tariff trial load data for 2019–20, while the profile for large business load control tariffs was based on the Energex CLP 9100. More details (on how these demand profiles were developed) are available in the reports for our October 2020 price determination. [12]

Demand profiles and historical energy cost levels

This section provides an overview of the demand profiles used for our analysis. Over the past number of years, the shape of the Queensland system-wide load profile has become 'peakier', with an increasing difference between the levels of peak and average demand (Figure 2). This is primarily due to a substantial uptake of rooftop solar PV, which has decreased daytime demand but has had limited effect on the evening peak demand.

Figure 2 Queensland system-wide load profile



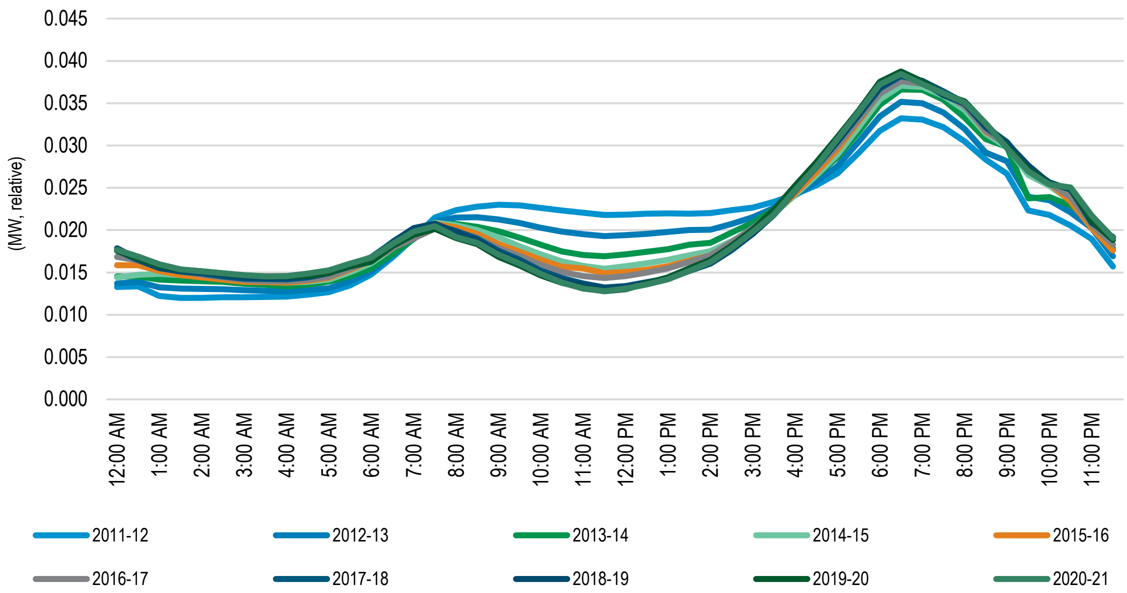
Note: 'MW, relative' means the annual loads for the profile have been scaled so they add up to one. This is an appropriate representation of the load, as it is the relative shape of the profile (rather than the absolute size) that determines wholesale energy costs.

Source: ACIL's analysis of data from AEMO.

Similarly, the Energex and Ergon NSLPs have also become 'peakier' over time due to the increased penetration of rooftop solar PV (Figures 3 and 4). On the Energex NSLP, more electricity from the grid is consumed during peak periods than on other demand profiles. Consequently, the Energex NSLP has the highest wholesale energy costs of the profiles analysed in Queensland. The Ergon NSLP is less 'peaky' than the Energex NSLP and consequently has lower wholesale energy costs.

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

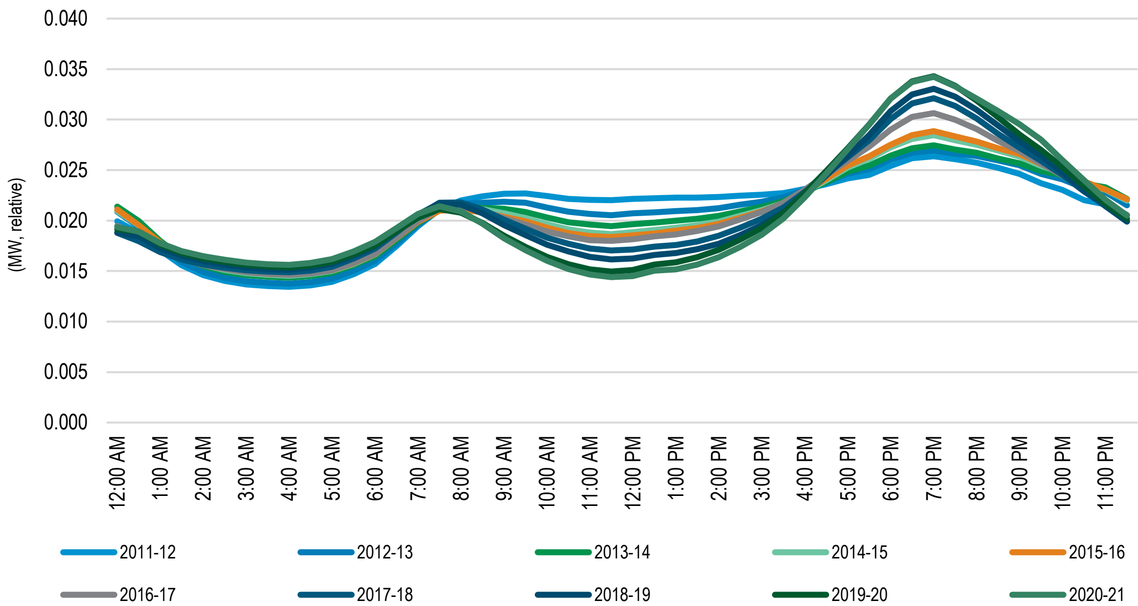
Figure 3 Energex NSLP



Note: 'MW, relative' means the annual loads for the profile have been scaled so they add up to one. This is an appropriate representation, as it is the relative shape of the profile (rather than the absolute size) that determines wholesale energy costs.

Source: ACIL's analysis of data from AEMO.

Figure 4 Ergon NSLP

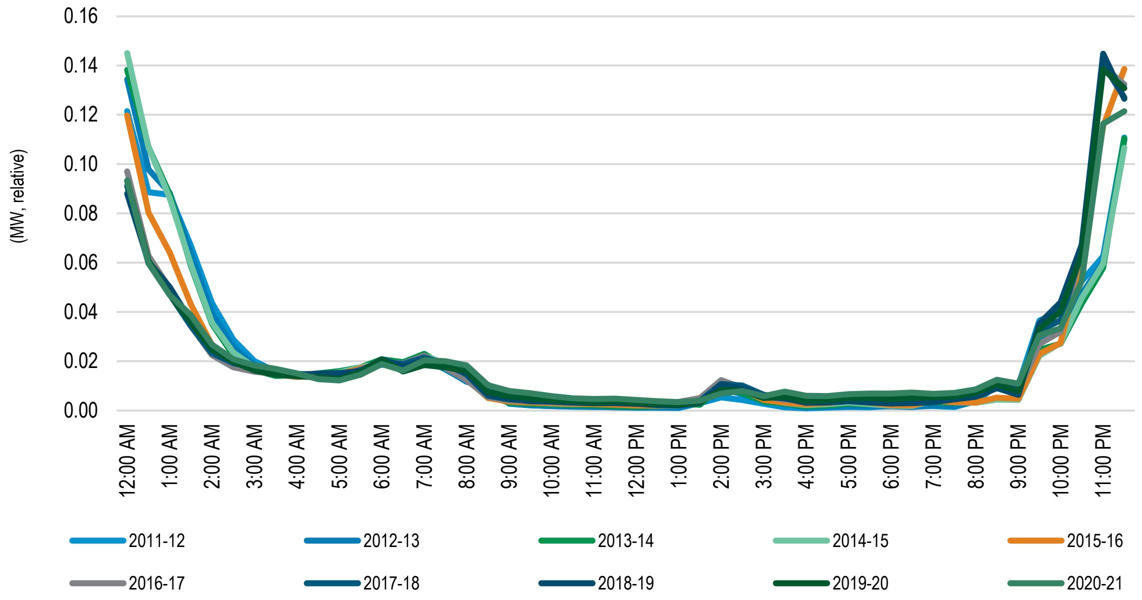


Note: 'MW, relative' means the annual loads for the profile have been scaled so they add up to one. This is an appropriate representation, as it is the relative shape of the profile (rather than the absolute size) that determines wholesale energy costs.

Source: ACIL's analysis of data from AEMO.

On the Energex CLPs, more electricity is generally consumed during off-peak periods and non-summer quarters (due to higher water heating loads in non-summer months) than on the Energex and Ergon NSLPs (Figures 5 and 6). Therefore, the Energex CLPs have lower wholesale energy costs relative to the NSLPs. The Energex CLP for retail tariff 33 typically has a higher wholesale energy cost than the Energex CLP for retail tariff 31. This is because the former generally has more electricity consumed during peak periods compared to the latter.

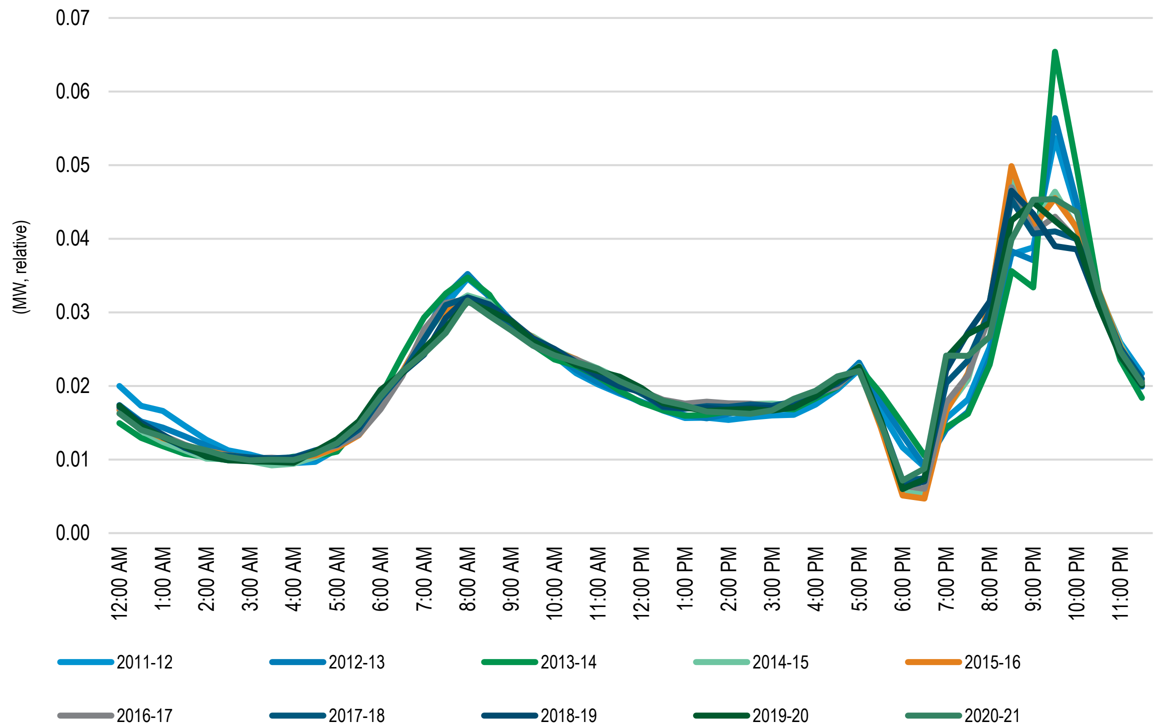
Figure 5 Energex CLP 9000 (retail tariff 31)



Note: 'MW, relative' means the annual loads for the profile have been scaled so they add up to one. This is an appropriate representation, as it is the relative shape of the profile (rather than the absolute size) that determines wholesale energy costs.

Source: ACIL's analysis of data from AEMO.

Figure 6 Energex CLP 9100 (retail tariff 33)

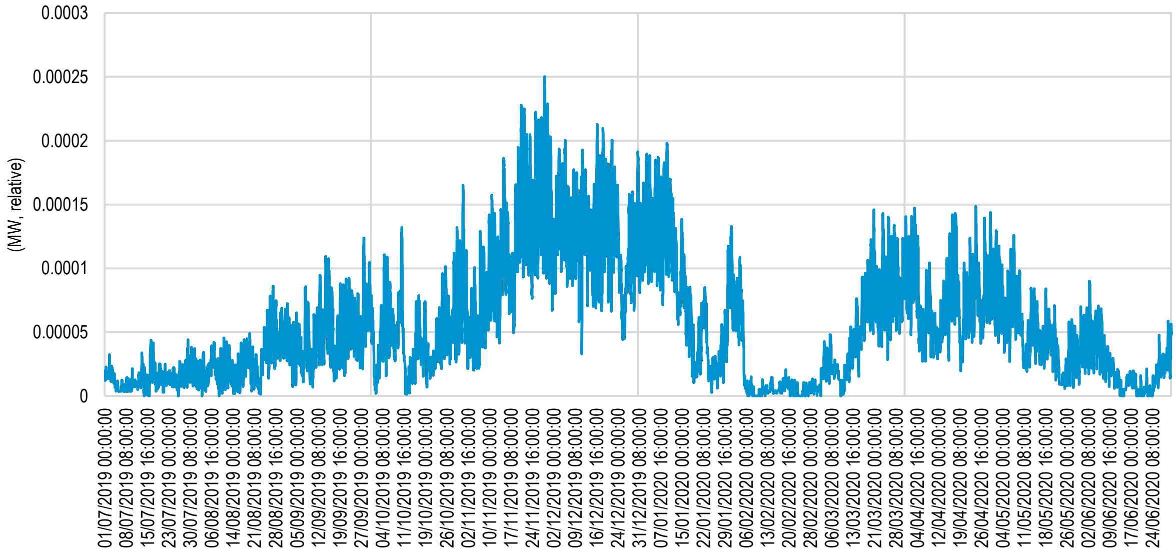


Note: 'MW, relative' means the annual loads for the profile have been scaled so they add up to one. This is an appropriate representation, as it is the relative shape of the profile (rather than the absolute size) that determines wholesale energy costs.

Source: ACIL's analysis of data from AEMO.

The demand profile for the small business load control tariff exhibits an extended period of low load, with loads tending to peak during summer—that is, between November and early January (Figure 7).

Figure 7 Energy CLP (small business)—tariff trial data, 2019–20



Note: 'MW, relative' means the annual loads for the profile have been scaled so they add up to one. This is an appropriate representation, as it is the relative shape of the profile (rather than the absolute size) that determines wholesale energy costs.

Source: ACIL's analysis of data from Energy Queensland's agricultural tariff trial.

Supply considerations

To simulate expected spot prices, ACIL has developed several datasets that reflect the supply dynamics within the NEM. These datasets include:

- thermal power plant availability—ACIL used its 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—using its renewable energy resource model, ACIL estimated a set of traces that reflects the availability and quality of renewable resources/generation (such as wind and solar) in different regions across the NEM by taking into account weather and geographical conditions.

  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 based on weather patterns
- generation information—ACIL maintains a reference case projection of the NEM, which 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 the draft determination, thermal generators have faced higher fuel costs. International gas prices and thermal coal export prices have been high and volatile during Q1 2022 as the war in Ukraine and sanctions against Russia added uncertainty to markets already impacted by global supply constraints (Figures 14 and 15). 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 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).[13] To achieve this, ACIL would routinely compare its detailed assumptions with AEMO's ISP and ESOO findings, including the technical parameters of generators, fuel prices and interconnector expansions. Any deviation in assumptions was investigated, and AEMO's findings were adopted if the deviation could not be justified. However, to date, ACIL's assumptions have been closely aligned with AEMO's findings.

Spot price simulation

ACIL applied its proprietary electricity model (PowerMark) to generate 561 simulations of 8,760 hourly wholesale electricity spot prices for 2022–23. PowerMark dynamically simulates the behaviour of generators in the NEM by 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 dynamic bidding algorithm allows PowerMark to account for changes in generators' bidding behaviour that are caused by evolving market conditions, such as the recent influx of renewable generation and changes in underlying costs.

ACIL advised that its wholesale spot price modelling broadly aligns with the market's expectations of spot price outcomes (ASX contracts) for 2022–23. More details are available in chapters 2 and 4 of ACIL's final report.

Hedged energy costs—hedging methodology and contract prices

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

ACIL used 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. Specifically, ACIL evaluated multiple strategies by varying the mix of base, peak and cap contracts for each quarter and analysing the resulting distribution of wholesale energy costs for each strategy.

Contract prices were estimated using the trade-weighted average of ASX Energy daily settlement prices of quarterly base, peak and cap contracts for 2022–23. To calculate the trade-weighted contract prices, ACIL used the Queensland contract prices and volume of contracts traded until 15 April 2022 inclusive.

Trading of ASX contracts tends to commence a number of years before the relevant financial year. For example, trading for 2022–23 ASX base contracts commenced as early as late 2018. This is a reflection of how market participants (such as retailers) purchase ASX contracts in advance to lock in their costs and manage spot price risk. More details on ACIL's approach are available in chapter 4 of its final report.

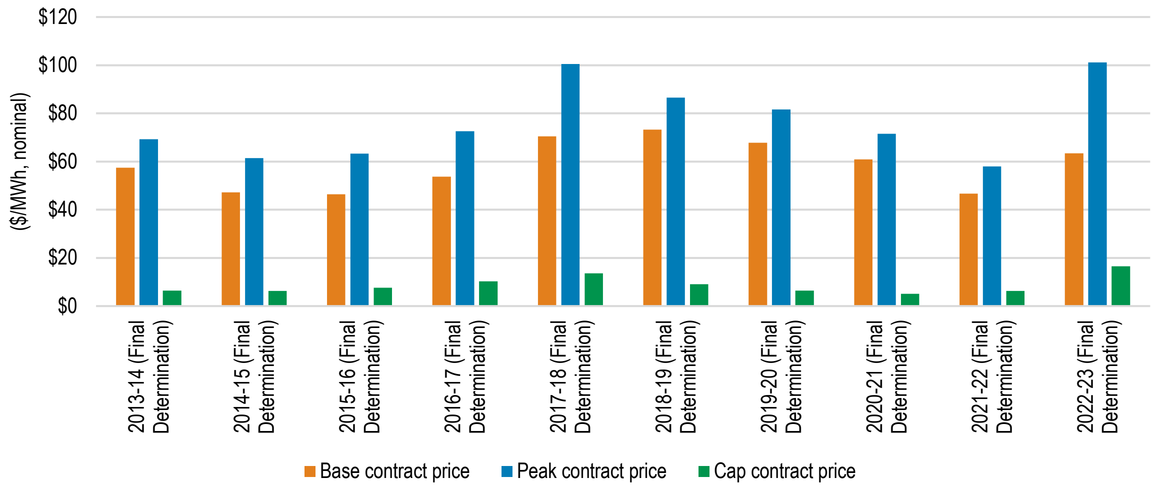
As shown in Figure 8, compared to last year's prices, contract prices for 2022–23, on an annualised and trade-weighted basis, have to date:

- increased by about $16.60/MWh for base contracts

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

- increased by about $43.10/MWh for peak contracts
- increased by about $10.20/MWh for cap contracts.

Figure 8 Annualised quarterly ASX contract prices ($/MWh)



Source: ACIL's analysis of data from ASX Energy.

This reflects market participants expecting an increase in spot prices, likely due to:

- a slowdown of renewable energy generators coming online (compared to recent years)
- reduced thermal generation availability, including the continued unavailability of the Callide C power plant (unit 4) and the closure of the Liddell coal-fired generator
- higher gas and coal prices.

Moreover, ASX cap contract prices have also increased substantially in 2022–23 compared to last year (Table 1). This likely reflects:

- market participants' expectations of higher spot price volatility due to reduced thermal generation availability and an expectation of further power plant outages
- uncertainties faced by cap contract providers around the ability of their peaking plant[14] to cover price spikes in the NEM under 5-minute settlement.

Holding other things constant, an increase of $1/MWh in cap contract price can increase the wholesale energy cost estimate for the NSLP by around $3/MWh due to the 'peaky' shape of the NSLP.

Table 1 Queensland trade-weighted ASX cap contract prices

Cap contract	*2021–2022 ($/MWh)*	*2022–2023 ($/MWh)*	*Change ($)*
Q3	2.18	13.32	11.14
Q4	5.73	15.04	9.31
Q1	13.99	29.53	15.54
Q2	3.30	8.31	5.01

Source: QCA's analysis of data from ASX Energy.

[14] Peaking plants, such as open-cycle gas turbine plants, usually have higher operating costs but very fast start-up and shut-down times compared with coal-fired generators. These plants can also change output rapidly.

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.

Our analysis—wholesale energy costs

Our position is to estimate the wholesale energy costs based on the advice from ACIL (discussed in section 4.2.1). We consider ACIL's use of a market-based approach is appropriate for the task of estimating wholesale energy costs. While other methods exist, notably a long-run marginal cost (LRMC) approach, we are satisfied that a market-based approach is the most appropriate. This is because, unlike a market-based approach:

- a LRMC approach generally does not reflect the prevailing market conditions within the NEM and relevant financial markets. Prevailing market conditions such as current electricity demand, supply–demand balance and market participants' expectations are likely to have a significant influence on wholesale energy costs
- cost information necessary to accurately undertake an LRMC approach is generally contained within confidential PPAs. Even if this information could be acquired, this approach would contribute to a lower level of transparency in our analysis.

Importantly, the market-based approach has the advantage of being more transparent than other methodologies, because it uses financial derivative data (i.e. ASX contract data) that are publicly available.

For the newly introduced load control tariffs[15] that commenced in November 2020, we consider it appropriate to continue using the recently developed representative demand profiles to estimate wholesale energy costs.[16] As uptake of these new tariffs is not yet widespread among customers, there is limited customer usage data to refine the demand profiles developed previously.

In developing its forecasts of demand profiles and generation supply/costs, ACIL used the latest available market data, including information on the uptake of rooftop solar PV, renewable energy resource traces, AEMO's latest peak demand and supply projections, and market participants' formal announcements on generation availability/operation. We consider that such an approach adequately takes into account the likely variation in demand profiles and generation supply/costs within the NEM.

We note that ACIL's approach has generated a distribution of spot prices for 2022–23 that is consistent with the distribution and variability of historical outcomes. This generated distribution covers a wide range of potential price outcomes that captures the extent and level of high spot price events, consistent with those observed historically.

Furthermore, ACIL's spot price modelling broadly aligns with the market's expectations of spot price outcomes (ASX contracts) for 2022–23. Generally, the purchase of ASX contracts enables retailers to lock in a price, or a maximum price (in the case of caps), at which a given volume of electricity will be transacted at a future date. Therefore, ASX contract prices incorporate market participants' risk-weighted expectations of future spot prices.

ACIL's approach also reflects how retailers, in practice, would build up a portfolio of financial derivatives in advance to minimise volatility in contract prices. To manage spot price risk, retailers generally purchase ASX contracts over a period ahead of the relevant financial year—to lock in the price (i.e. contract price) for an amount of electricity that they would pay for in the future. Contract prices fluctuate due to the actual and

[15] These include the load control tariffs for small and large business customers, i.e. tariffs 34, 60A and 60B.
[16] The representative demand profiles were developed as part of the October 2020 determination. See QCA, *Supplementary review: Regulated retail electricity prices for 2020–21*, final determination, October 2020.

anticipated changes in the supply–demand balance within the NEM and contract markets at a particular point in time.

Consequently, past contract prices—reflecting the market's expectations of future spot prices at an earlier time—may have a significant impact on the wholesale energy costs incurred by retailers over a period if the market's expectations change noticeably. This is because retailers would have locked in their future electricity prices in advance, based on the contract prices at that time.

To account for this effect, ACIL's approach has estimated trade-weighted contract prices by using all available trade data for a given product (i.e. back to the first trade recorded by ASX Energy) rather than pre-specifying a particular pattern in the build-up of a portfolio of financial derivatives.

To estimate wholesale energy costs, ACIL took the 95th percentile of the distribution of 561 annual hedged energy costs for a given demand profile. We consider this is a conservative estimate, given that the 95th estimate is at the upper end of ACIL's projected hedged cost outcomes, which is less likely to underestimate the wholesale energy costs that prudent retailers face in the NEM.

Developments in the period between the draft and final determinations

As discussed, the level of wholesale energy costs is determined by the prevailing market conditions in the NEM and relevant financial markets. Our approach in estimating wholesale energy costs is designed to closely reflect these market dynamics, which are best approximated by publicly available prices and trade volumes of ASX contracts.

In practice, retailers adopt a range of hedging strategies to manage spot price volatility within the NEM[17], including through the purchase of ASX contracts. Generally, the purchase of ASX contracts enables retailers to lock in a price, or a maximum price (in the case of cap contracts), at which a given volume of electricity will be transacted at a future date.

The significant movement in ASX contracts was partially captured in our draft determination with a data cut-off date of 21 January 2022. Trade-weighted prices for the final determination were calculated using prices and volume of ASX contracts traded until 15 April 2022 inclusive. Such an approach allows us to take into account more current information (including developments over the potentially volatile summer period), while still meeting our final determination timeframe.

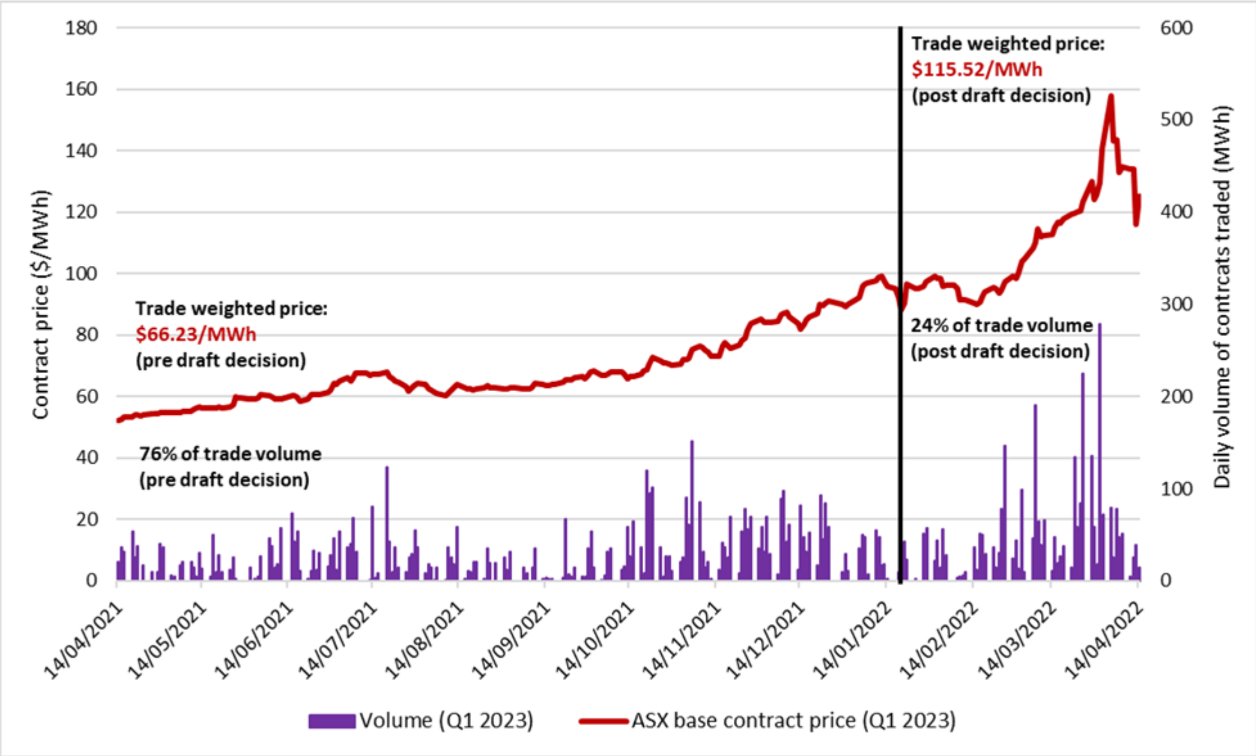
Since the draft determination, there has been a large increase in the trade-weighted prices of ASX contracts. Since 21 January, trade-weighted prices for:

- quarterly ASX base contracts have increased to a level between $87/MWh and $116/MWh compared to being between $46 and $66/MWh prior to 21 January
- quarterly ASX cap contracts have increased to a level between $12/MWh and $35/MWh compared to being between $6 to $26/MWh prior to 21 January.

These large increases in ASX contract prices are illustrated in the following figures:

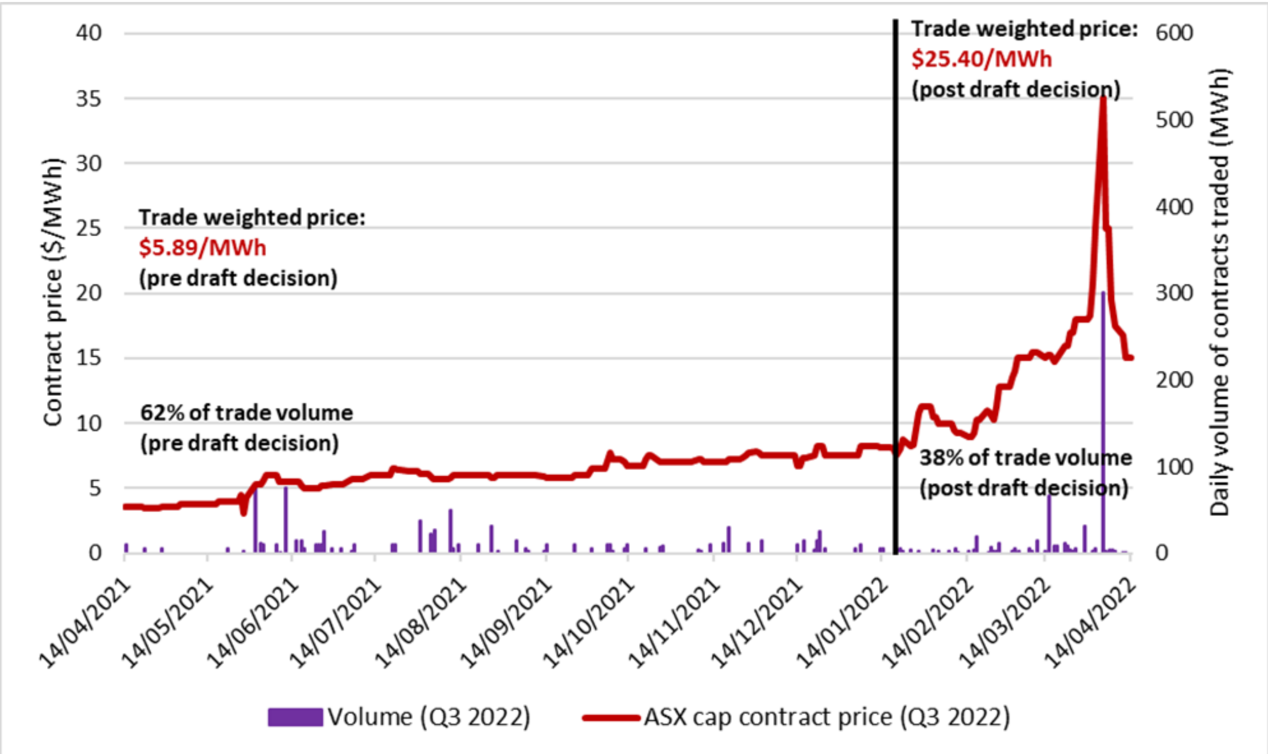
[17] The NEM is a volatile market where spot prices are settled every 5 minutes and currently can range from –$1,000 to $15,100 per megawatt hour (MWh).

Figure 9 Queensland ASX base contract 2022–23 (Q1 2023)



Source: QCA's analysis of data from ASX Energy.

Figure 10 Queensland ASX cap contract 2022–23 (Q3 2022)



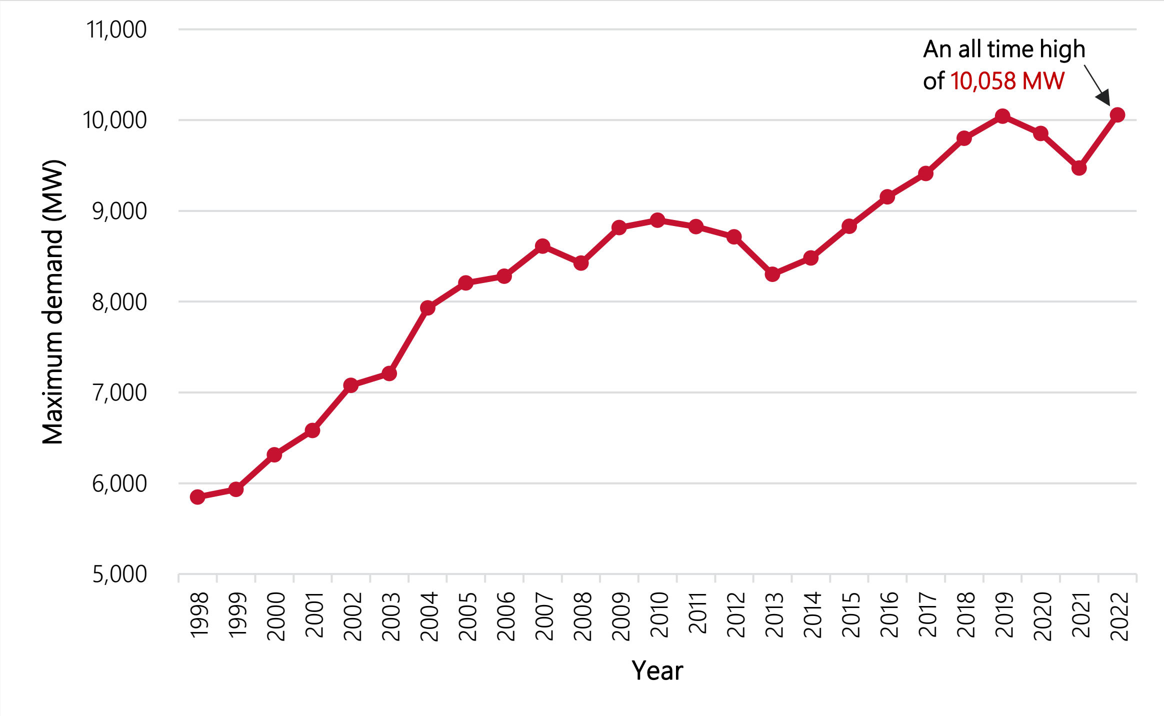
Source: QCA's analysis of data from ASX Energy.

Market developments since 21 January led market participants to revise their price and demand expectations when trading in ASX contracts for 2022–23. These developments include significant episodes of weather-related high demand coupled with reduced generation availability and higher fuel prices faced by generators, which contributed to higher spot prices and increasing price volatility in Queensland.

Weather-related high demand

Northern and central parts of Queensland have experienced severe to extreme heatwaves in the first week of March, which was the state's fifth warmest on record.[18] This has led to demand in Queensland reaching an all-time high of 10,058 MW on 8 March (Figure 11). Warm conditions on this day (maximum temperatures between 33°C and 38°C) and continuous periods of elevated humidity were key drivers of this record. Another key episode was on 2 February, when warm and humid conditions (the third consecutive day of a heatwave), coupled with cloud cover reducing rooftop PV output resulted in unusually high demand during the day (Figure 12).

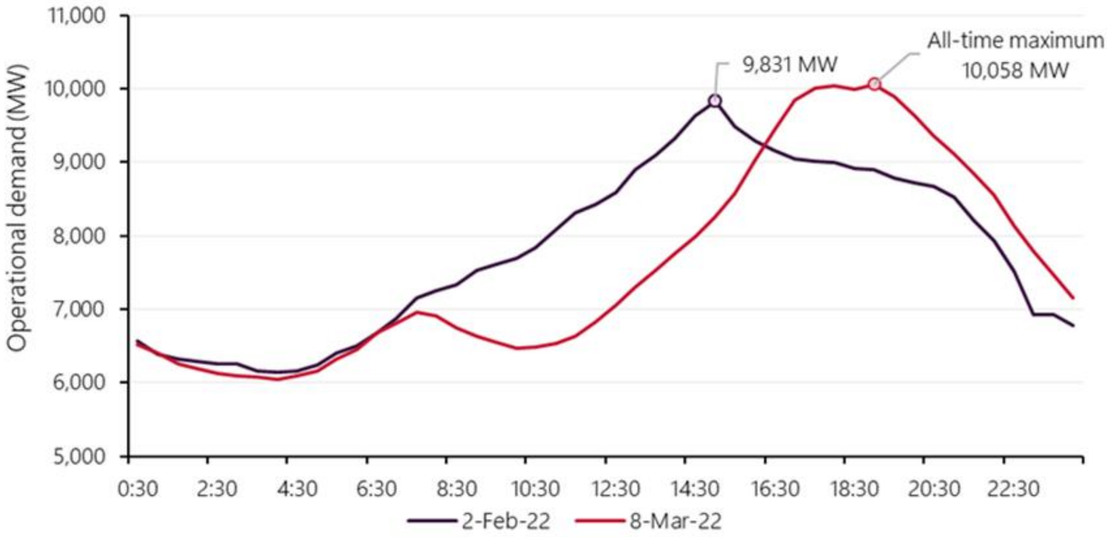
Figure 11 Queensland annual maximum demand



Source: QCA's analysis of data from AEMO.

[18] See Bureau of Meteorology, *Queensland in March 2022,* BOM website, Australian Government, 2022, accessed 11 May 2022.

Figure 12 Elevated Queensland demand on 2 February and 8 March 2022



Source: AEMO.

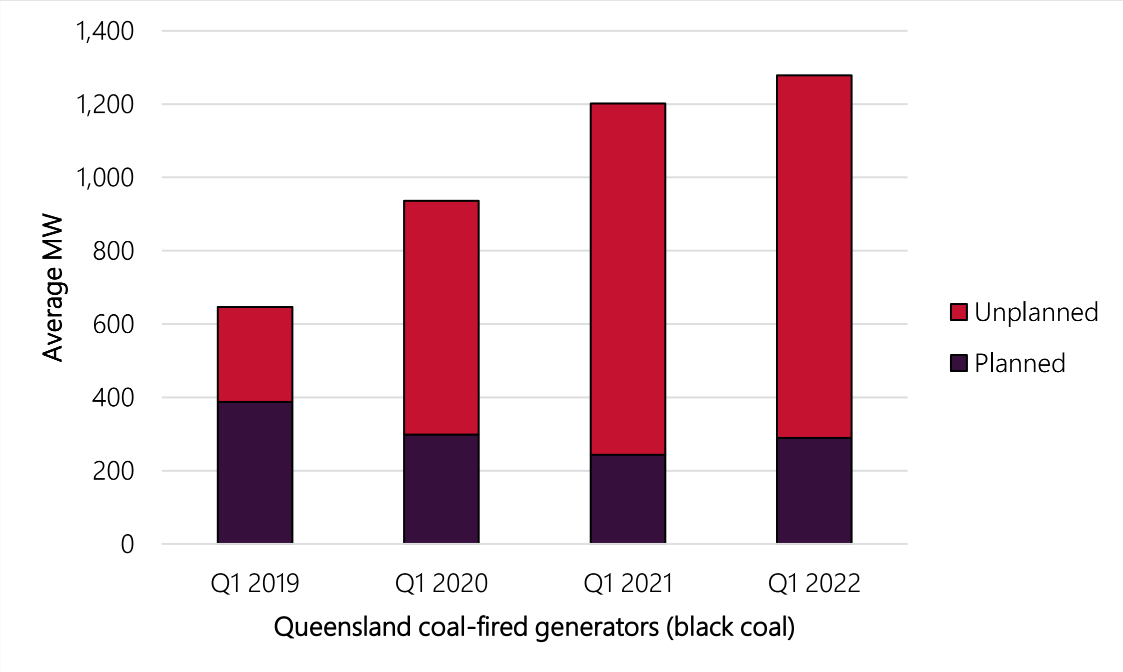
Reduced thermal generation availability

Coal-fired and gas-powered generators in Queensland have suffered from increased unplanned outages. In terms of coal-fired generators, unplanned outages at both Callide C and Kogan Creek have reduced output by 355 MW and 207 MW respectively in Q1 2022. Callide C (unit 4) has remained out of service since its major incident in Q2 2021, while Kogan Creek was out of service for around 26 days due to an unplanned outage. Compared to Q1 2021, the level of unplanned outages for black coal-fired generators in Queensland has increased by approximately 3 per cent (Figure 13).

Despite having almost no outages, average output at the Tarong coal-fired power plant has declined noticeably (by 165 MW) as units continued to offer capacity at reduced levels in Q1 2022. The Swanbank E gas-fired generator has also been out of service for the entire Q1 2022 following damage to the station's automatic voltage regulator (AVR) in December 2021.[19]

[19] AEMO, *Quarterly Energy Dynamics Q1 2022*, April 2022.

Figure 13 High levels of outages for coal-fired generators in Queensland



Source: QCA's analysis of data from AEMO.

Higher fuel prices

Thermal generators are facing higher fuel costs. Domestic gas prices have remained at or near record levels, averaging around $10 per gigajoule (GJ) in Q1 2022, an increase of 67 per cent, compared to $6/GJ in Q1 2021 (Table 2). AEMO reported that recent average gas prices have set new Q1 records in the Short Term Trading Markets (STTMs) for both Brisbane and Adelaide and Victoria's Declared Wholesale Gas Market (DWGM). The Gas Supply Hub (GSH) and Sydney STTM saw their second highest Q1 price levels on record since 2017.[20]

Table 2 Average wholesale gas prices

Domestic gas market	*Q1 2021 ($/GJ)*	*Q1 2022 ($/GJ)*	*Change (%)*
Brisbane STTM	6.36	10.22	61
Adelaide STTM	6.05	10.18	68
Sydney STTM	6.05	9.81	62
Victoria's DWGM	5.52	9.47	72
GSH	6.12	9.97	63

Note: An STTM is a wholesale market that facilitates short-term trading between gas shippers and gas customers. STTMs operate in Adelaide, Brisbane and Sydney. Victoria's DWGM is a wholesale market that supports trading of gas at the Declared Transmission System (DTS). The GSH supports the trade and movement of gas by allowing participants to trade short-term physical gas products at the pipelines in Wallumbilla (in western Queensland) and Moomba (in northern South Australia).

Source: AEMO.

International gas prices and thermal coal export prices have been high and volatile during Q1 2022 as the war in Ukraine and sanctions against Russia added uncertainty to markets already impacted by global supply constraints. Asian LNG prices have been volatile, with a peak price of A$53/GJ in Q1 2022, compared to a

[20] AEMO, *Quarterly Energy Dynamics Q1 2022*, April 2022.

peak price of less than A$30/GJ in Q1 2021 (Figure 14). Thermal coal export prices averaged around A$367/tonne in Q1 2022, after briefly reaching a record high of A$604/tonne in early March. Compared to Q1 2021, coal export prices have increased by approximately 250 per cent (Figure 15).

Figure 14 Increasingly volatile and elevated Asian LNG prices

Source: AEMO and Bloomberg Intercontinental Exchange (ICE) data.

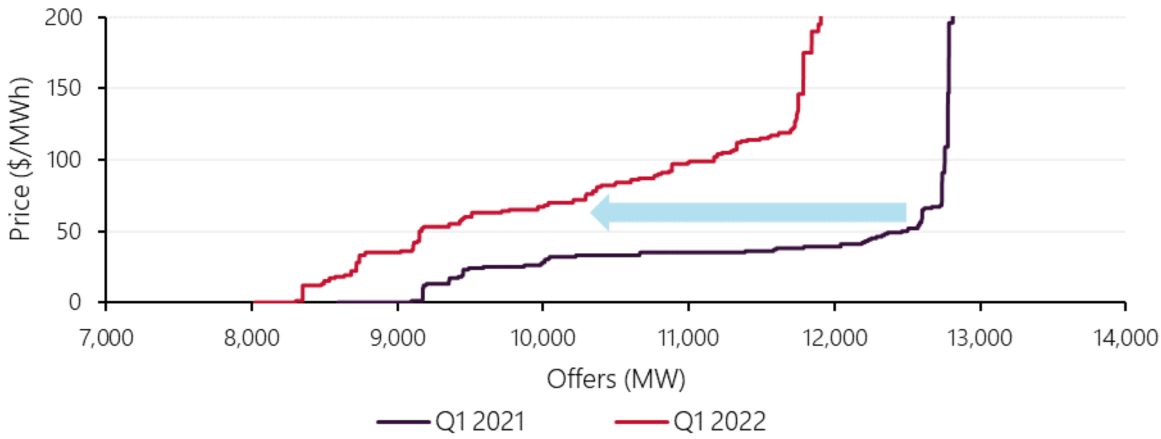
Figure 15 New record high in Newcastle thermal coal export prices

Source: AEMO and Bloomberg Intercontinental Exchange (ICE) data.

Further, coal-fired generators in the NEM have been repricing their offers by shifting a substantial amount of supply offered to higher price bands. Compared to Q1 2021, over 3,000 MW of capacity from black coal-fired generators was shifted from lower price bands to prices above $60/MWh (Figure 16). This is the largest year-on-year quarterly change since the commencement of the NEM, and it coincided with the surge in international coal prices to record levels.[21]

[21] AEMO, *Quarterly Energy Dynamics Q1 2022*, April 2022.

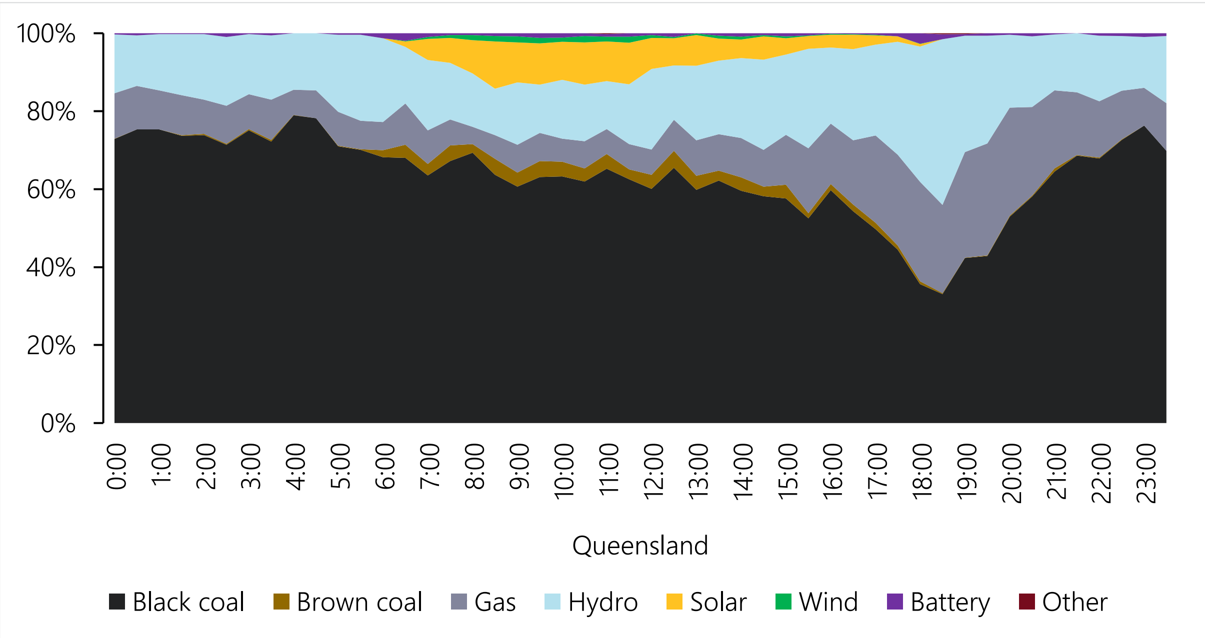
Figure 16 Significant shift in supply offered by coal-fired generators to higher price bands



Source: AEMO.

Despite recent significant growth in renewable generation, gas and coal-fired power plants continue to be the last generator dispatched to meet demand for each 5-minute interval with their offer prices determining spot prices in Queensland.[22] In Q1 2022, coal-fired generators set spot prices around 60 per cent of the time, while gas-fired plants determined prices approximately 10 per cent of the time (Figure 17). This spot price setting dynamic, coupled with higher gas and coal prices, have contributed to elevated spot prices and ASX contract prices.

Figure 17 Spot price setting frequency by generator type and time of day in Queensland—Q1 2022



Note: While there is no brown coal generation in Queensland, the interconnectedness of the NEM means that the offer of a brown coal generator from Victoria may set spot prices in Queensland.

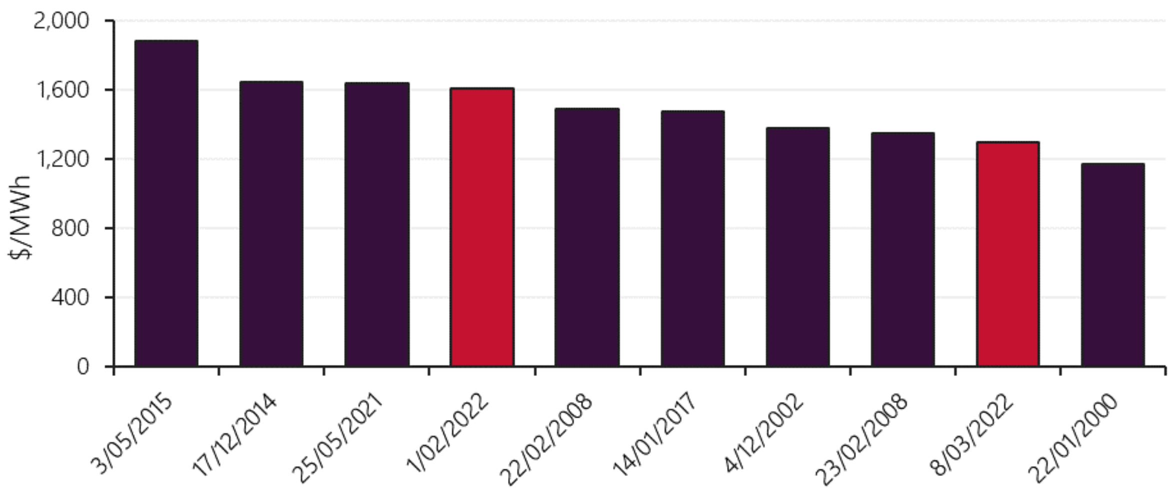
Source: QCA's analysis of data from AEMO.

[22] Spot prices in the NEM are determined using a marginal pricing approach. In other words, the spot price for each 5-minute period is determined by the offer price of the last generator dispatched to meet demand, irrespective of the offer prices of other generators.

Higher spot prices and increasing price volatility

Heatwave conditions, high demand, reduced generation availability, higher fuel prices, and coal-fired generators repricing their offers led to higher spot prices and increasing price volatility in Q1 2022. For example, average spot prices for 1 February and 8 March were amongst the 10 highest daily levels recorded in Queensland since commencement of the NEM (Figure 18).

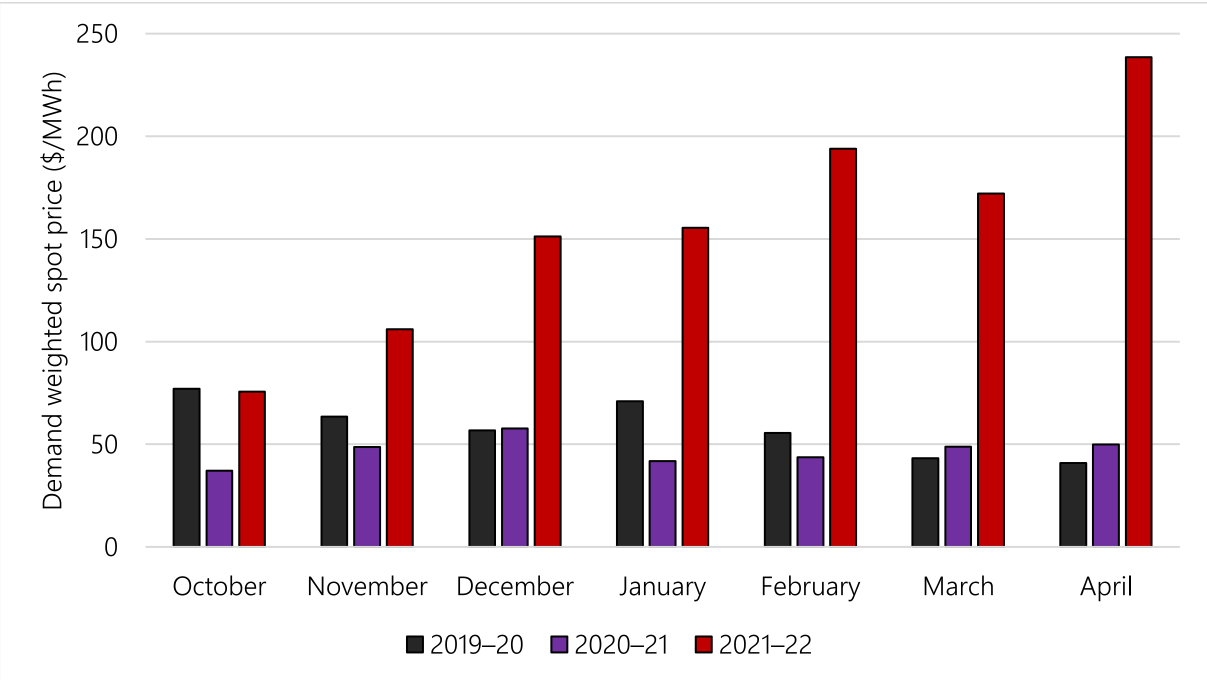
Figure 18 Two of Queensland's 10 highest average daily spot prices occurred in Q1 2022



Source: AEMO.

Since the draft determination, we have also observed a sustained period of high spot prices. Monthly average spot prices ranged from $155/MWh to $194/MWh in Q1 2022, compared to average prices between $42/MWh and $49/MWh in Q1 2021 (Figure 19).

Figure 19 Elevated Queensland average spot prices



Note: Estimates for April were calculated using data until 15 April 2022 inclusive to be consistent with the data cut-off date for the final determination.

Source: QCA's analysis of data from AEMO.

Not only have average spot prices remained elevated since the draft determination, but there has also been a significant number of high price events in Queensland. The AER reported and investigated 12 cases of 30-minute wholesale electricity prices that breached $5,000/MWh in Q1 2022, compared to zero breaches in Q1 2021. Since the commencement of 5-minute settlement in October 2021, there has been a substantial increase in the number of spot prices exceeding $300/MWh, with such spot prices occurring 569 times in Q1 2022 compared to 18 times in Q1 2021.

However, the number of spot price intervals has increased by a factor of six since the introduction of the 5-minute settlement. To ensure that spot price occurrences under 30-minute and 5-minute settlement are more comparable, we have estimated the contribution of spot prices exceeding $300/MWh as a share of demand-weighted average spot prices. To date, we observed that the contribution of spot prices greater than $300/MWh has been substantially higher since the commencement of 5-minute settlement with a peak of around $92/MWh in February 2022 (Table 3).

Table 3 Contribution of Queensland spot prices exceeding $300/MWh

Month	***2019–20***	***2020–21***	***2021–22***
	30-minute settlement [a]		***5-minute settlement [a]***
October	–	$1.16	$13.17
November	–	$4.85	$27.69
December	$0.07	$2.44	$62.30
January	$10.19	$2.07	$42.50
February	$0.04	$3.78	$92.21
March	$0.39	$7.19	$64.23
April [b]	–	$10.50	$31.83

Note: (a) To ensure that spot price occurrences under 30-minute and 5-minute settlement are more comparable, we have estimated the contribution of spot prices exceeding $300/MWh as a share of demand-weighted average spot prices.

(b) Estimates for April were calculated using data until 15 April 2022 inclusive to be consistent with the data cut-off date for the final determination.

Source: QCA's analysis of data from AEMO.

Conclusion

We consider ACIL's market hedging approach to be appropriate, noting it:

- adequately addresses the issues raised in stakeholder submissions
- closely reflects the prevailing market conditions within the NEM and relevant financial markets (such as the ASX contract markets). This was achieved by using the most up-date data to undertake a large number of simulations to account for potential variation in demand, thermal plant availability, output of renewable generation and spot price outcomes. Further, market participants' expectations were incorporated by using the most recent publicly available ASX contract data.

Other energy costs

In addition to estimating wholesale energy costs, we need to account for other energy costs that retailers incur when purchasing electricity from the NEM:

- renewable energy target (RET) costs
- NEM management fees and ancillary services charges
- prudential capital costs
- Reliability and Emergency Reserve Trader (RERT) costs
- costs associated with the Retailer Reliability Obligation (RRO).

Our position is to estimate other energy costs based on ACIL's advice (discussed in section 4.2.1).

Renewable energy target

The RET scheme provides incentives for the electricity sector to increase generation from renewable sources and reduce greenhouse gas emissions. It consists of the large-scale renewable energy target (LRET) and small-scale renewable energy scheme (SRES). The costs of these incentives are paid by retailers through the purchase of large-scale generation certificates (LGCs) and small-scale technology certificates (STCs).

LGCs or STCs can be created when eligible electricity is generated by utility-scale renewable generators or small-scale renewable systems. Retailers surrender the purchased LGCs and STCs to the Clean Energy Regulator (CER) to meet their obligations under the RET scheme.

Large-scale renewable energy target

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. The mandated LRET is 33,000 GWh for both 2022 and 2023.[23]

Retailers must purchase a set number of LGCs according to the:

- renewable power percentage (RPP) published by the CER
- amount of electricity they have acquired and sold to customers in the calendar year.

To estimate the LRET costs, ACIL used a market-based approach by forecasting the expected average LGC prices and RPP values. Under this approach, LRET costs (in $/MWh) for the relevant calendar years were estimated by multiplying the expected average LGC prices and RPP values. The LRET cost for the financial year was derived by averaging the two calendar-year estimates. The expected LGC prices were estimated using the latest LGC forward prices[24], while the RPP values were calculated using data published by the CER.

ACIL estimated that the LRET cost for 2022–23 will be $5.00/MWh for all retail tariffs—an increase of $0.71/MWh compared to the 2021–22 determination. This increase is due to higher LGC forward prices.

We consider this approach to be appropriate as it reflects the current market conditions for LGCs, which are likely to have a significant influence on the LRET costs to be incurred by retailers in 2022–23. It is also preferable to a cost-based approach that uses the LRMC of renewable energy generation. This is because, unlike the market-based approach:

[23] *Renewable Energy (Electricity) Act 2000* (Cth), s. 40. For more information, see http://www.cleanenergyregulator.gov.au.

[24] Forward prices are predetermined prices for an underlying commodity, currency, or financial asset, as agreed between the buyer and seller of a forward contract, to be transacted at a future date.

- the LRMC of renewable generation generally does not reflect the prevailing market conditions for LGCs. Prevailing market conditions such as the market participants' expectations and supply–demand balance for LGCs are likely to have a significant influence on LGC prices and therefore LRET costs
- cost information necessary to accurately undertake an LRMC approach is generally contained within confidential PPAs. Even if this information could be acquired, this approach would contribute to a lower level of transparency in our analysis.

Large-scale generation certificate prices

The expected LGC prices were estimated using LGC forward prices[25] provided by TFS Australia (an energy brokerage company). ACIL estimated the expected LGC prices by using the trade-weighted average (rather than the simple average) of LGC forward prices for 2022 and 2023. This approach assumes that retailers build up their LGC coverage over a period of time to meet their obligations under the LRET scheme.

ACIL estimated the expected LGC prices to be $28.94/MWh for 2022 and $24.72/MWh for 2023. LGC forward prices have increased since they were last estimated for the 2021–22 determination.

The LGC forward market is an active market consisting of several brokers and trading platforms. As such, we consider that it provides a sound basis for estimating the value of LGCs. LGC forward pricing provides an indication of the current market view of LGC costs that a retailer will face to meet their obligations under the LRET scheme. We consider this approach is appropriate, as it reflects the prevailing market conditions for LGCs and therefore the LGC costs that retailers are likely to incur.

Renewable power percentage

The RPP values dictate the number of LGCs that a retailer needs to purchase and surrender to the CER. The CER has determined the RPP for 2022 at 18.64 per cent.

To estimate the 2023 RPP, ACIL used the mandated LRET targets, the cumulative adjustment[26] (published by the CER) and its estimates of electricity acquisitions for 2023. The RPP value was estimated by dividing the LRET target by the electricity acquisitions of liable entities. This approach to calculating the RPP aligns with the CER's. The estimated RPP is 18.64 per cent for 2023. We consider ACIL's approach to estimating the RPP to be appropriate for this determination, as it aligns with the CER's expectations and therefore reflects the LRET obligations that retailers will likely face in practice.

Small-scale renewable energy scheme

The SRES provides an incentive for individuals and small businesses to install eligible small-scale renewable energy systems—such as solar panel systems, small-scale wind systems, small-scale hydro systems, solar hot water systems and heat pumps. Customers installing these systems create STCs, which retailers must purchase and surrender to the CER to fulfil their obligations under the SRES.

As with the LRET, retailers must purchase a set number of STCs according to the:

- small-scale technology percentage (STP) published by the CER
- amount of electricity they have acquired and sold to customers in the calendar year.

ACIL estimated the SRES costs by multiplying the expected STC price and the relevant calendar-year STP. The SRES cost for the financial year was derived by averaging the two calendar-year estimates.

[25] Forward prices are predetermined prices for an underlying commodity, currency, or financial asset, as agreed between the buyer and seller of a forward contract, to be transacted at a future date.
[26] This is a mechanism used by the CER to ensure that liable entities surrender only the number of LGCs needed to meet the legislated renewable energy targets.

The SRES cost for 2022–23 is estimated to be $10.90/MWh for all retail tariffs—a decrease of $0.62/MWh compared to the 2021–22 determination. This is driven by an expected decrease in the STPs and therefore the number of STCs that retailers are required to purchase.

We consider that ACIL's methodology to estimating SRES costs is appropriate, as it aligns with the way retailers are likely to incur these costs in practice, taking into account CER's requirements and STC clearing house processes.

Small-scale technology certificates price

The expected STC price was based on the CER's clearing house price. The STC clearing house is operated by the CER, and the clearing house price is currently fixed at $40 per STC (per MWh of electricity generated by eligible renewable systems).

We consider that ACIL's approach of estimating the expected STC price is appropriate. Although there is an active market for STCs, these market prices are unlikely to be the best indicator of future STC prices. This is because the STC market is designed to clear every year, with the CER adjusting the STPs annually with a target STC price of $40 per certificate (i.e. the CER's clearing house price).

Small-scale technology percentage

The STP values dictate the number of STCs that retailers need to purchase and surrender to the CER. To estimate the STPs for the final determination, ACIL has used the CER's binding STP of 27.26 per cent for 2022 and its own estimate of 27.26 per cent for 2023. The 2022 binding STP is higher than the CER's earlier published non-binding estimate of 22.4 per cent, reflecting a higher uptake in small-scale renewable energy systems than previously estimated.

For this final determination, ACIL Allen has opted to use its own forecast of the 2023 STP, rather than the CER's non-binding estimate. We consider this approach to be appropriate, as ACIL's more recent forecast will capture the latest developments in the uptake of small-scale renewable energy systems. This is also consistent with the AER's approach to estimating the SRES costs in its 2022–23 DMO final determination.

Given the CER typically determines the final SRES liabilities for the second half of the financial year about nine months after our final determination, we have historically provided a pass-through to reflect the actual SRES costs that retailers incur (discussed in section 5.3).

NEM management fees and ancillary services charges

When purchasing electricity from the NEM, retailers incur fees to cover the costs of operating the NEM and managing power system safety, security and reliability.

NEM management fees

NEM management fees are levied by AEMO to cover its costs related to operating the NEM, full retail contestability, the funding of Energy Consumers Australia, the 5-minute settlement compliance and distributed energy resource (DER) integration program.

To estimate the NEM fees for 2022–23, we have consulted AEMO to account for the step change in upcoming NEM fees due to AEMO's sizable deficit. To assist with our process, AEMO provided a draft document containing updated 2022–23 estimates, which was presented to its financial consultation committee.[27] The NEM fee estimates have been updated using the draft budgeted percentage changes contained in this document.

[27] See AEMO, *Draft FY2023 Budget & Fees*, presentation to Finance Consultation Committee, 4 March 2022.

ACIL estimated that for 2022–23, NEM fees will be $1.13/MWh, an increase of $0.64/MWh, compared to the 2021–22 determination. This reflects an increase in costs related to operating the NEM, the 5-minute settlement compliance and the DER integration program.

We consider ACIL's approach to estimating the NEM fees is appropriate, as it reflects how retailers are likely to incur these costs in practice, taking into account AEMO's latest budget and projected fees.

Ancillary services charges

Ancillary services charges cover the costs of services used by AEMO to manage power system safety, security and reliability. These services maintain key technical characteristics of the electricity grid, including standards for frequency, voltage, network loading, and system restart processes. Ancillary services are divided into three major categories—Frequency Control Ancillary Services (FCAS), Network Support Control Ancillary Services (NSCAS) and System Restart Ancillary Services (SRAS).

ACIL estimated the ancillary services charges using the region-specific average ancillary service payments[28] observed over the preceding 52 weeks. For 2022–23, ancillary services charges were estimated to be $1.42/MWh, an increase of $1.01/MWh, compared to the 2021–22 determination. This increase is driven by higher costs for FCAS in Queensland. Higher FCAS costs have occurred on days when outages related to upgrades of the Queensland to New South Wales interconnector (QNI) required significantly increased local supply of FCAS.

We consider ACIL's methodology is appropriate, given the highly uncertain nature of ancillary service costs, which are heavily dependent on the state of the power system and the amount of service required at any particular time to maintain power system security and reliability. In practice, the need for ancillary services (and therefore costs) can vary significantly from period to period.

Prudential capital costs

Prudential capital costs are the costs that a retailer incurs to provide financial guarantees to AEMO and to lodge initial margins with the ASX in order to trade in futures contracts (also known as AEMO and hedge prudential costs). ACIL estimated these prudential costs in line with the latest published AEMO requirements and margin requirements for trading in the ASX futures market.

Prudential costs for customers, whose prices are settled on the Energex NSLP, were estimated using the consumption profile of the Energex NSLP. These costs were also used as a proxy for the prudential costs of the Energex CLPs. Similarly, prudential costs of the Ergon NSLP were estimated using the consumption profile of the Ergon NSLP.

Prudential costs were estimated to increase compared with last year, largely driven by higher contract prices and higher expected price volatility in the NEM. ACIL estimated the 2022–23 prudential costs to be $2.55/MWh for the Energex NSLP (and CLPs) and $2.10/MWh for the Ergon NSLP.

We consider that ACIL's approach to estimating prudential costs is appropriate, as it aligns with how retailers are likely to incur these costs in practice, taking into account AEMO's prudential requirements and the ASX's margin requirements.

AEMO prudential costs

When sourcing electricity from the NEM, a retailer is required to provide financial guarantees to AEMO. These financial guarantees (prudential obligations) are essential for AEMO to manage credit risks associated

[28] AEMO provides data on weekly settlements for ancillary service payments in each interconnected region within the NEM.

with a retailer's financial ability to meet its contractual obligations when purchasing electricity from the NEM.

When estimating the AEMO prudential costs, ACIL assumed that the retailer has no vertical integration (through generation ownership or PPAs) and does not engage in reallocation of prudential obligations. Reallocation is an AEMO procedure that allows counterparties to reduce their prudential obligations through instruments such as swaps or options.

To determine the required prudential obligations, AEMO assesses and calculates a maximum credit limit (MCL) for each counterparty (or retailer in this context). ACIL used the MCL, the relevant consumption profiles and the costs of funding a bank guarantee to estimate the AEMO prudential costs that a retailer is expected to incur.

ACIL estimated the 2022–23 AEMO prudential costs to be $0.74/MWh for the Energex NSLP (and CLPs) and $0.59/MWh for the Ergon NSLP. More details on ACIL's approach are available in chapter 4 of its final report.

We consider ACIL's approach to estimating the AEMO prudential costs to be appropriate, as it reflects how retailers are likely to incur these costs in practice, considering AEMO's prudential requirements. This approach generally reflects the simplest way that a retailer could fulfil its prudential obligations to AEMO.

If a retailer chooses to adopt a more complex approach to meet its prudential obligations (such as engaging in a relocation of obligations using swaps or options), it is likely that the retailer perceives additional benefits in doing so. On this basis, we consider that ACIL's approach should result in a conservative estimate for the costs of meeting AEMO's prudential obligations.

Hedge prudential costs

Retailers are required to lodge initial margins with the ASX to trade in ASX futures contracts. These margins are essential for the ASX to manage risks associated with a retailer's financial ability to meet its contractual obligations when trading in futures. The costs of these margins (hedge prudential costs) must be accounted for, as ASX futures were relied upon to hedge spot price risks and derive the wholesale energy costs estimates. ACIL estimated the hedged prudential costs considering:

- the costs of funding the margins—noting that the funds lodged as margins with the ASX receive a money market return that offsets some of the funding costs
- the ASX parameters that determine the initial margin—including the price scanning range, intra-monthly spread charge and spot isolation rate for base, peak and cap contracts
- the annual average prices for base, peak and cap contracts
- the consumption profiles of the Energex and Ergon NSLPs.

An additional margin may apply when contract prices move in an unfavourable manner for the buyer or seller of ASX contracts. However, ACIL did not provide an allowance for an additional margin, as it is assumed that favourable and unfavourable movements in contract prices will cancel each other out over time.

ACIL estimated the 2022–23 hedge prudential costs to be $1.81/MWh for the Energex NSLP (and CLPs) and $1.51/MWh for the Ergon NSLP. More details on ACIL's approach are available in chapter 4 of its final report. We consider that ACIL's approach to estimating the hedge prudential costs is appropriate, as it aligns with the way retailers are likely to incur these costs in practice, considering the ASX's margin requirements.

Reliability and Emergency Reserve Trader scheme

Retailers incur a fee levied by AEMO to cover the costs of the Reliability and Emergency Reserve Trader (RERT) scheme. The RERT scheme is a mechanism that allows AEMO to contract for emergency reserves, such as generation or demand response outside of the NEM. This mechanism is meant to provide AEMO with the flexibility it needs when managing power system reliability while minimising the costs to consumers.

ACIL considered it challenging to project these costs with a sufficient degree of accuracy. It noted that while it may be possible to project the RERT costs using its previous costs and AEMO's projection of unserved energy (USE)[29], there is currently insufficient data to do so.

Therefore, as with the ancillary services, ACIL estimated the RERT costs using the costs published by AEMO for the preceding 12-month period. On 25 May 2021, AEMO activated the RERT to assist with power system management following the major incident at the Callide power station. AEMO reported the costs of this activation to be $452,881. By dividing this activation cost with the total energy requirements in Queensland, this RERT cost was estimated to be $0.01/MWh.

AEMO also activated the RERT on 1 February 2022 following high demand (due to heatwave conditions) coupled with reduced generation availability. AEMO reported the expected costs of this activation to be $50,960,399. By dividing this activation cost with the total energy requirements in Queensland, this RERT cost was estimated to be $1.00/MWh. Summing the RERT costs associated with these two events resulted in a total RERT cost of $1.01 for 2022–23.

We consider that ACIL's methodology is appropriate, given the highly uncertain nature of the RERT costs—the RERT scheme is only called upon by AEMO under extreme circumstances. AEMO uses the RERT scheme as a safety net if a critical shortfall in reserves is forecast. The RERT scheme is only activated once all market options have been exhausted, generally during periods when the supply–demand balance is tight.

Retailer Reliability Obligation

The Retailer Reliability Obligation (RRO) was implemented on 1 July 2019. The RRO is designed to assist with managing the risk of declining reliability of generation supply, in response to the recent influx of intermittent renewable generation coupled with the recent or potential closures of thermal power plants.

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. At this stage, for 2022–23, the RRO has not been triggered for Queensland, and therefore no RRO costs have been incurred.

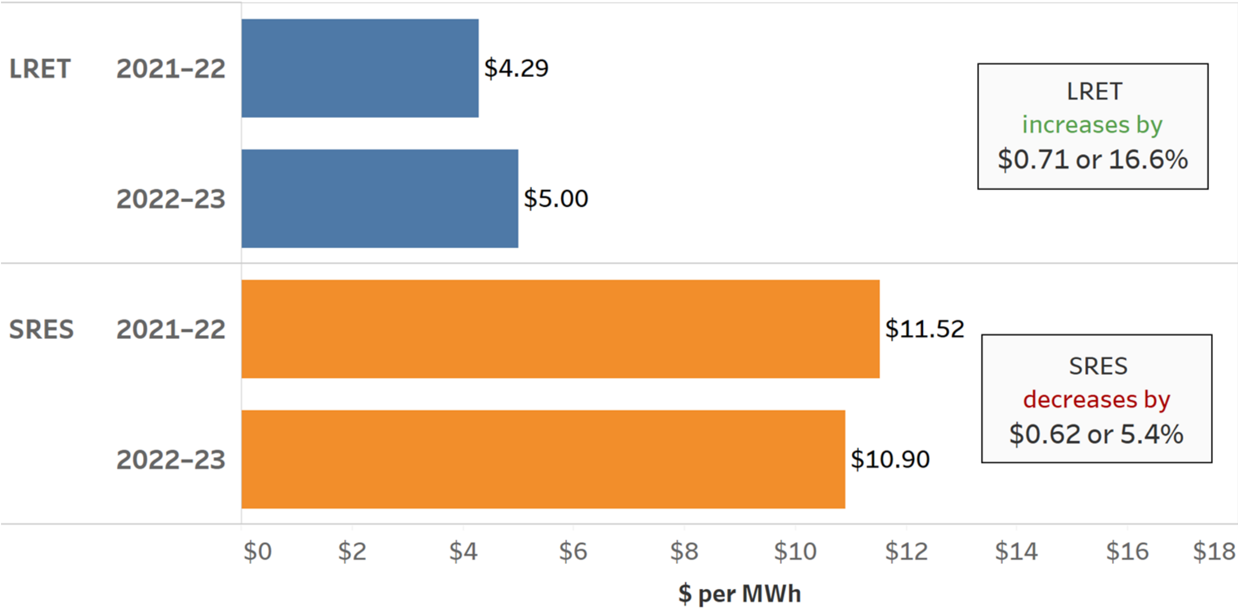
However, we consider that this cost component should be incorporated as part of the wholesale energy costs, as retailers are required to modify their contract cover (such as using ASX contracts) to ensure sufficient coverage if the RRO is triggered. We will consider the appropriate methodology to account for the RRO costs when the RRO is triggered for Queensland.

[29] USE is the electricity that cannot be supplied to consumers, resulting in involuntary loss of customer supply (load shedding). USE generally occurs due to insufficient levels of generation capacity, demand response or network capability to meet demand.

Summary of other energy costs

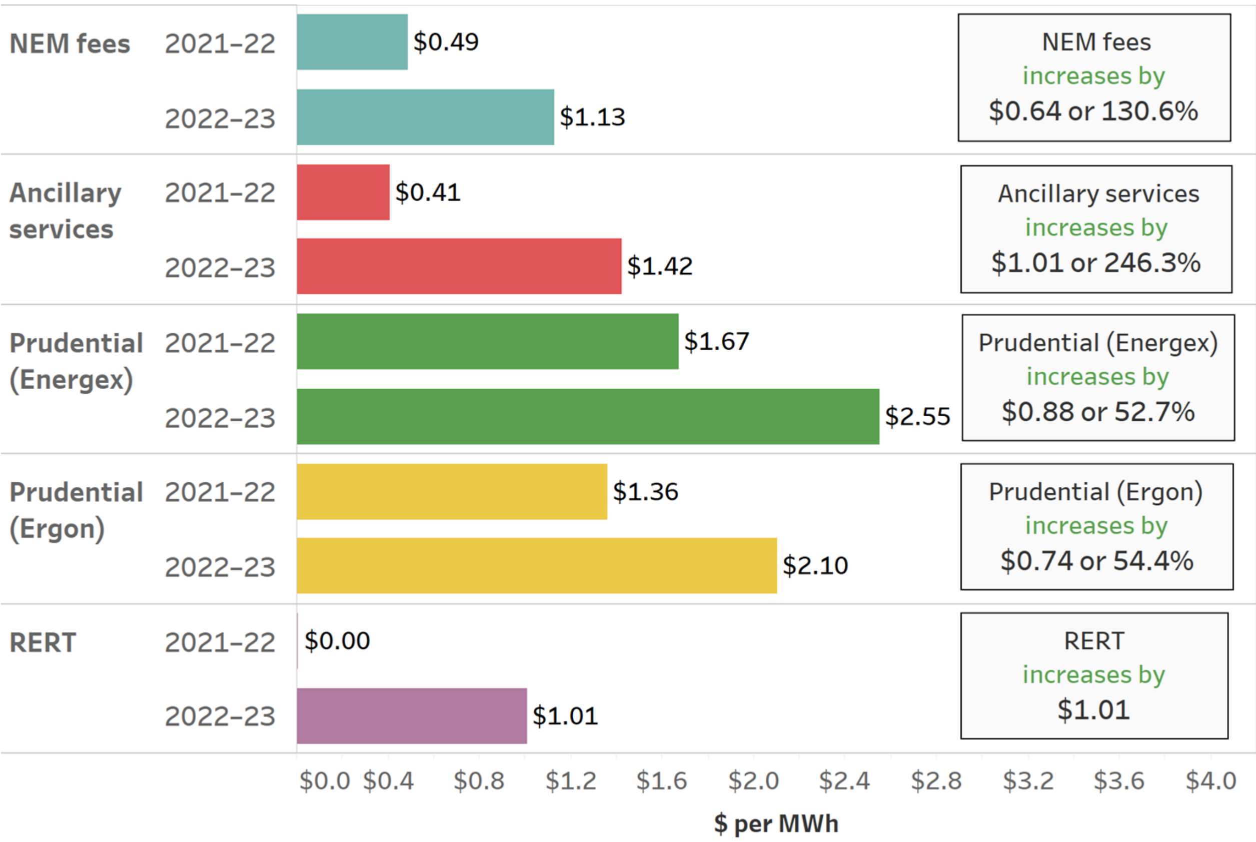
The charts below summarise the other energy costs that retailers are expected to incur.

Figure 20 Other energy costs—LRET and SRES



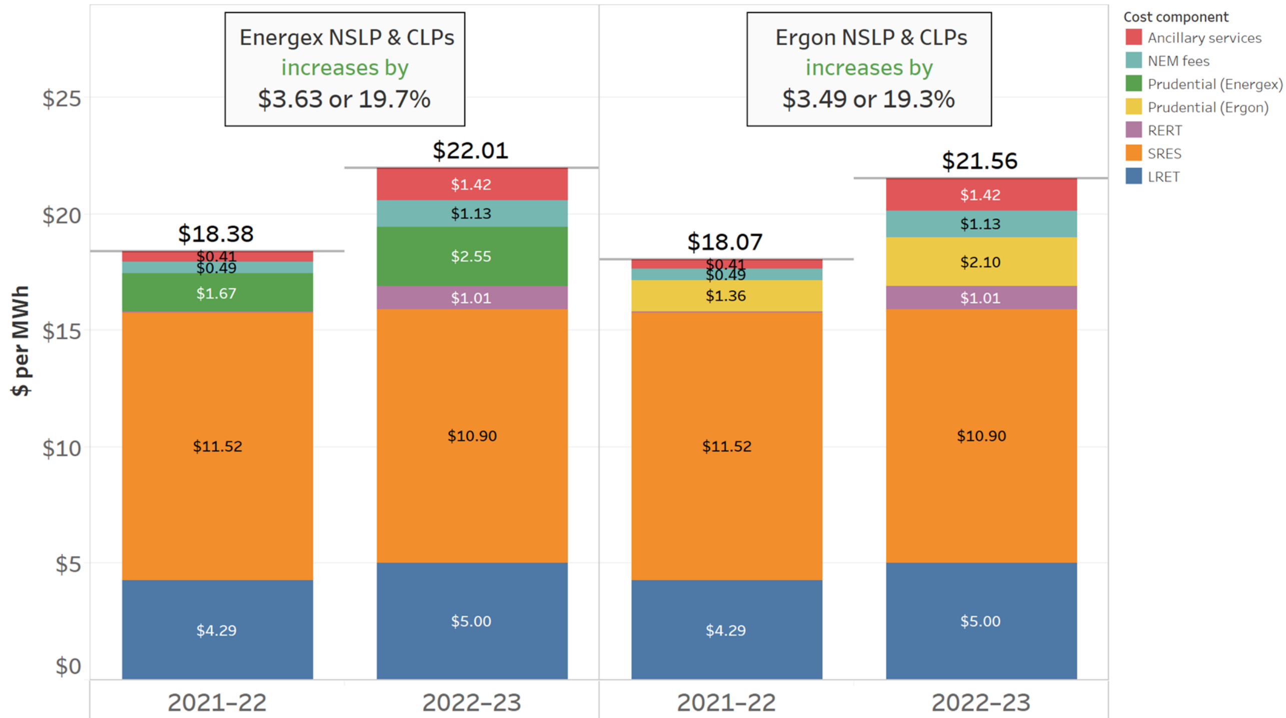
Source: QCA's analysis of data from ACIL Allen.

Figure 21 Other energy costs



Source: QCA's analysis of data from ACIL Allen.

Figure 22 Total other energy costs



Source: QCA's analysis of data from ACIL Allen.

Energy losses

Some electricity is lost when it is transported over transmission and distribution networks to customers. As a result, retailers must purchase additional electricity to allow for these losses when supplying customers.

ACIL accounted for energy losses by applying the latest transmission and distribution loss factors published by AEMO in a manner that aligns with AEMO's NEM settlement process. These loss factors are:

- the average energy-weighted transmission loss factor—estimated by ACIL, using the loss factors and energy consumed at each of the transmission node identities (TNI) provided by AEMO
- the distribution loss factor published by AEMO.

The calculated losses in ACIL Allen's final report have been updated to reflect AEMO's 2022–23 published loss factors. Compared to estimates for last year, overall energy loss factors[30] have:

- increased for small customer tariffs, reflecting higher distribution and transmission loss factors
- increased for large customer tariffs, reflecting higher distribution loss factors
- decreased for very large customer tariffs, reflecting a decline in transmission loss factors.

Our position is to estimate the energy losses based on ACIL's advice. Given ACIL's methodology's alignment with AEMO's settlement process, we consider the methodology is likely to best reflect the actual energy losses incurred by retailers.

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

Total energy cost allowances for 2022–23

The chart below summarises the changes in total energy cost allowances for 2022–23.

Figure 23 Changes in total energy cost allowances

Note: Totals may not add up precisely due to rounding.

Source: QCA's analysis of data from ACIL Allen.

APPENDIX D: STANDING OFFER ADJUSTMENT APPROACH AND DEFAULT MARKET OFFER COMPARISON

As part of our price determination, the Minister asked us to consider the costs and benefits associated with standing offers in SEQ and the effects of the AER's default market offer (DMO) on notified prices.[31]

At this time, we consider it appropriate to include a standing offer adjustment (SOA) in notified prices, to account for the more favourable terms and conditions typically offered in standard contracts.

This appendix provides clarity around our approach to calculating the value of the SOA. It also describes how we undertook a like-for-like comparison between the notified price bills and equivalent DMO reference bills.

SOA approach

We have previously discussed details on the approach we apply to determine the value of the SOA.[32] For clarity, we set out our approach below.

Overall, our approach uses the maximum costs a customer may avoid on a standard contract, relative to a market contract, as a proxy for the benefit a customer can derive.

To identify the maximum avoided costs, we sourced data on the retail fees attached to residential and small business flat rate market offers for the June quarter 2021, reported in our publicly available SEQ retail electricity market monitoring report 2020–21.[33]

We then calculated the maximum fee amount for each retailer, as a simple accumulation of each fee type levied by that particular retailer. This means zero values[34] were included in the analysis—but ultimately had no bearing on the final accumulated value of each retailer's maximum fees.[35]

Our approach of identifying the maximum avoided costs (the maximum costs a market contract customer may incur above a standard contract customer), necessarily requires us to include the full fee amount levied by each retailer.[36] For this reason, we did not seek to weight the costs based on the percentage of customers who may incur them.

However, we did make adjustments to avoid any double or triple counting of mutually exclusive fee types (for example, fees associated with different payment methods). Given the standard contract contains dishonour payment fees, we did not include these fees in our analysis. Our intention is to assess fees that could be incurred on a market contract but that are avoided (not incurred) on a standard contract; thus, including them would lead to the maximum avoided costs being overstated.

Once the maximum avoided costs were derived, we determined the percentage they formed of the small customer's average flat-rate market offer bill, using residential and small businesses annual electricity bill

[31] Appendix A (Minister's delegation), covering letter, p. 2.
[32] See, for example, QCA, *Regulated retail electricity prices for 2021–22*, final determination, June 2021, pp. 54–57.
[33] QCA, *SEQ retail electricity market monitoring 2020–21*, December 2021, pp. 60 (table 14) and 68 (table 16).
[34] Either where a retailer did not offer that service or offered it but did not charge for it.
[35] As the purpose of the analysis is to assess what value retailers attach to terms and conditions (explicitly), the sample used must necessarily contain fees that retailers have explicitly valued separately to the cost of electricity supply.
[36] This includes account establishment fees, as a customer establishing an account will incur this fee.

data for the June quarter 2021, reported in our publicly available SEQ retail electricity market monitoring report 2020–21.[37]

Consistent with last year's approach, we used the average maximum avoided costs, and reached an SOA value of 3.7 per cent.[38]

DMO comparison

The delegation asks us to consider the default market offer (DMO). Consistent with previous years, we have compared the notified price bill (including the SOA) to the equivalent DMO bill in SEQ and considered reducing the SOA for small customers where the notified price bill exceeds the equivalent DMO bill.

To undertake this comparison, we used the notified prices (including the 3.7 per cent SOA[39]) set out in Appendix G and compared them to the AER's final DMO annual bills for 2022–23.

The AER determined four DMO bills (for SEQ) for the following tariff groups—residential flat-rate tariff, residential flat-rate with load control tariffs, residential time-of-use tariff and small business flat-rate tariff.[40]

Using the same approach we adopted last year, we assessed the components of the DMO bill and notified price bill to undertake a like-for-like comparison. This included taking account of:

- metering costs, which are included in the DMO bills but not in our notified prices.[41] To undertake an equivalent comparison, we have excluded the value of metering costs (i.e. alternative control services charges and advanced meter costs) from the DMO bills
- GST, which is included in the DMO bills, but not in our notified prices. To ensure that the comparison is made on a like-for-like basis, we have excluded the value of GST from the DMO bills
- consumption levels, which are different for the DMO bills, compared to the levels we used to calculate our notified price bill impacts. To ensure that the bills are comparable, we have used the DMO consumption levels when calculating the equivalent notified price bills
- the AER's allocation for load control tariffs. To calculate a single DMO bill for both tariffs 31 and 33, the AER has used an apportioning approach with an allocation of 29 per cent for tariff 31 and 71 per cent for tariff 33. To undertake an equivalent comparison, we have applied the same approach as the AER to calculate a single notified price bill for load control tariffs (i.e. by using the AER's allocation methodology).

The like-for-like comparison between the notified price bills and equivalent DMO reference bills (after adjusting for the factors set out above) are shown in the charts below.

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[37] QCA, *SEQ retail electricity market monitoring 2020–21: Appendices*, December 2021, pp. 51 (table 33) and 52 (table 34).

[38] We used a simple average, as we are of the view that it provides a reasonable reflection of maximum avoided costs, without the added complexity associated with alternative methods.

[39] See section 5.1 of the main report.

[40] AER, *Default market offer prices 2022–23*, final determination, May 2022.

[41] We generally do not regulate metering charges for small customers (except for those on advanced digital meters). At this stage, most small customers in Queensland are on accumulation meters (only a small minority are on advanced digital meters).

Residential flat-rate tariff (tariff 11)

The equivalent notified price bill for tariff 11 is $66.40 lower than the DMO bill. Therefore, we do not need to adjust the notified price of tariff 11.

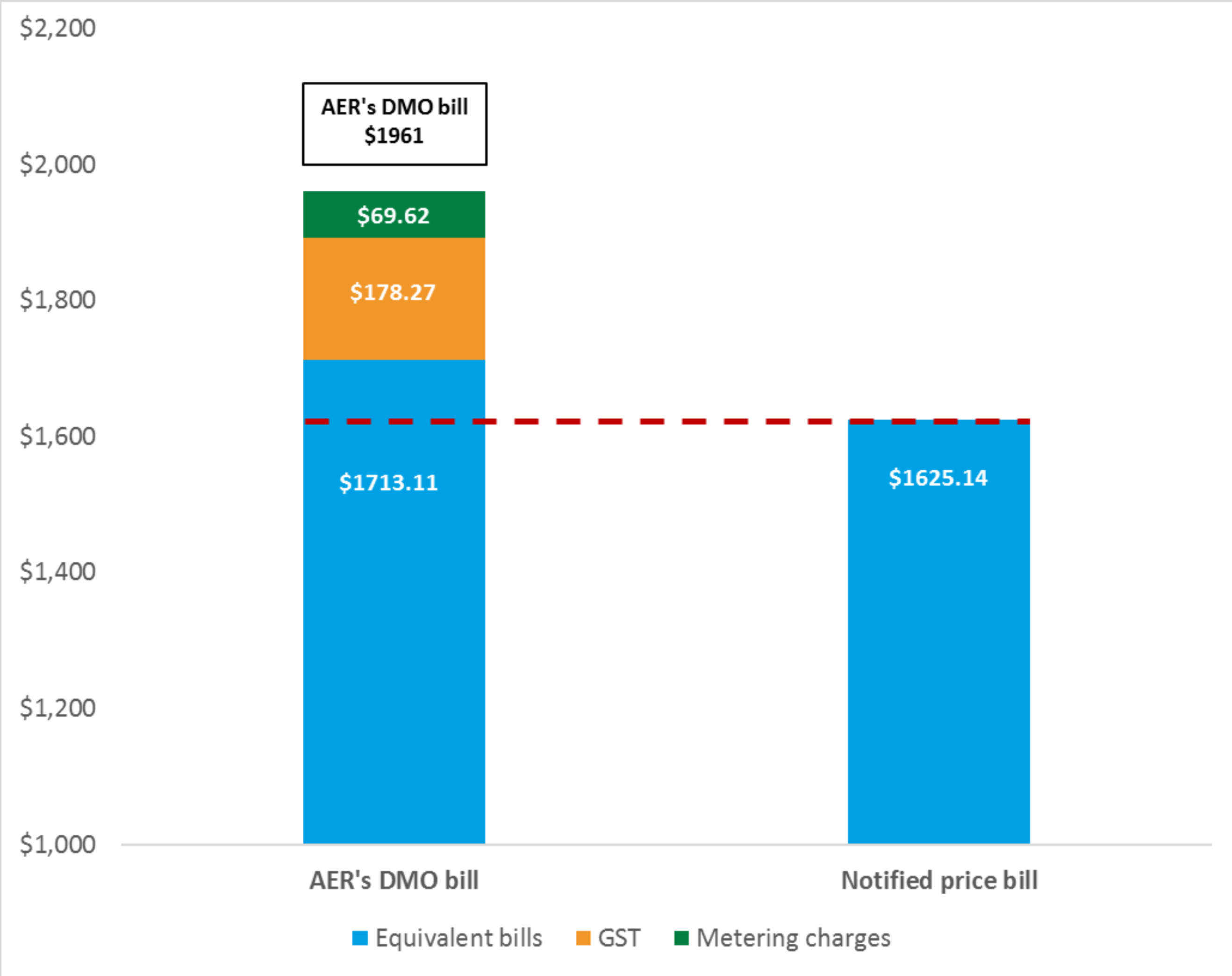
Figure 24 Residential flat-rate tariff—equivalent annual bills

Note: A DMO consumption level of 4,600 kWh per annum was used to calculate the equivalent notified price bill.

Residential flat-rate with load control tariffs (tariffs 11, 31 and 33)

The equivalent notified price bill for tariffs 11, 31 and 33 is $87.97 lower than the DMO bill. Therefore, no adjustment is necessary for the notified price of tariffs 31 and 33.

Figure 25 Residential flat-rate with load control tariffs—equivalent annual bills



Note: A DMO consumption level of 4,400 kWh per annum (tariff 11) and 1,900 kWh per annum (tariffs 31 and 33) were used to calculate the equivalent notified price bill. Applying the AER's allocation methodology resulted in a consumption level of 551 kWh per annum for tariff 31 (29 per cent of 1,900 kWh per annum) and 1,349 kWh per annum for tariff 33 (71 per cent of 1,900 kWh per annum).

Residential time-of-use tariff (tariff 12B)

Among the suite of time-of-use tariffs, we consider tariff 12B to be comparable to the DMO residential time-of-use tariff, as tariff 12B is based on the Energex time-of-use network tariff in SEQ. The equivalent notified price bill for tariff 12B is $106.77 lower than the DMO bill. As such, no adjustment is required to the notified price of tariff 12B.

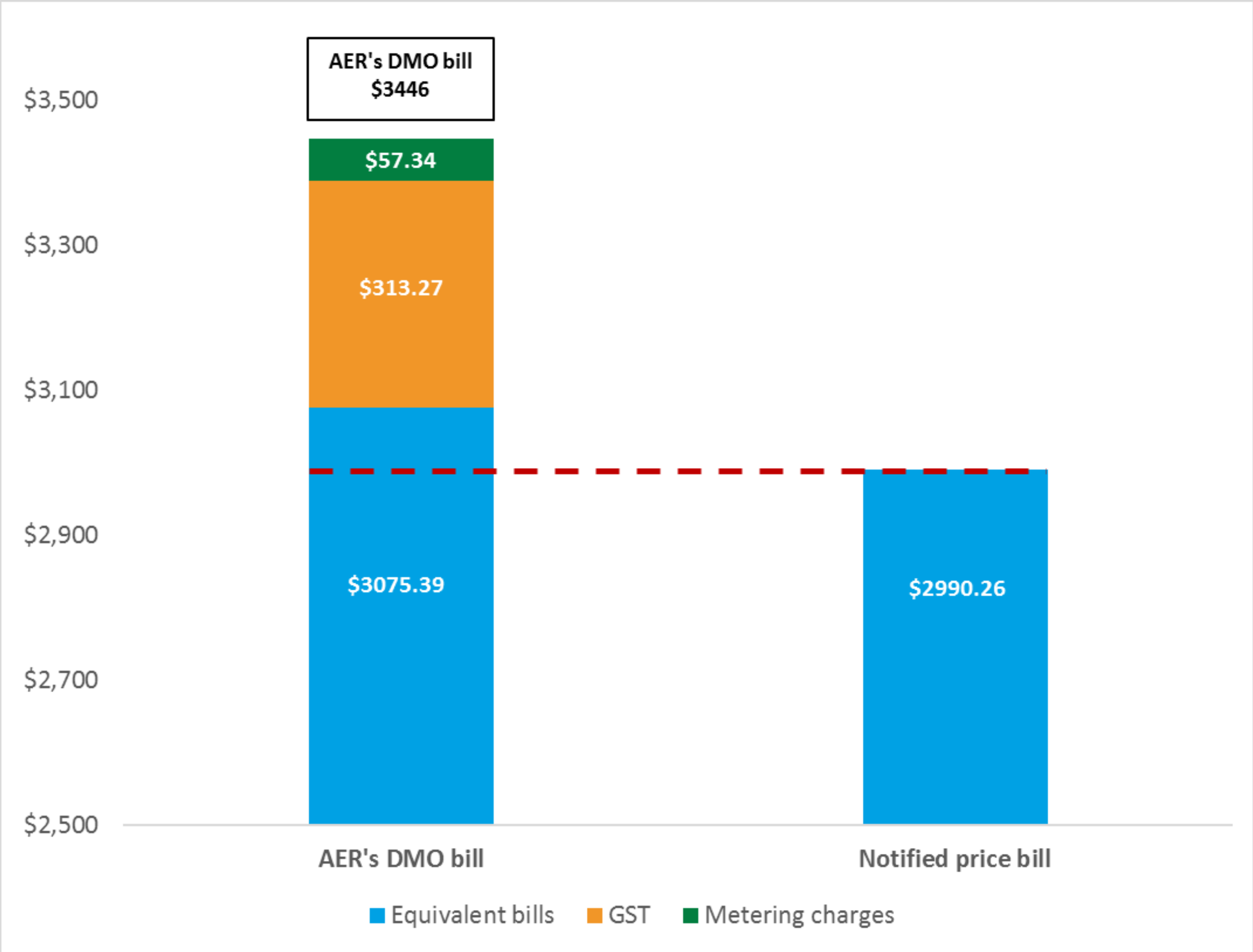
Figure 26 Residential time-of-use tariff—equivalent annual bills

Note: The AER's DMO pattern of supply for a time-of-use tariff was used to calculate the equivalent notified price bill.

Small business flat-rate tariff (tariff 20)

The equivalent notified price bill for tariff 20 is $85.13 lower than the DMO bill. Hence, no further adjustment to the notified price of tariff 20 is required.

Figure 27 Small business flat-rate tariff—equivalent annual bills



Note: A DMO consumption level of 10,000 kWh per annum was used to calculate the equivalent notified price bill.

APPENDIX E: 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 notified prices (discussed in section 5.2).

The approach we used involves the following two steps:

- estimate the under- or over-recovery of SRES costs in 2021–22, and then
- calculate SRES costs to be passed through in the 2022–23 notified prices.

Estimate the under- or over-recovery of SRES costs in 2021–22

First, we calculated the actual cost of SRES compliance during 2021–22, based on the Clean Energy Regulator's final small-scale technology percentage (STP) for 2021 and 2022.

We then compared the actual cost of SRES compliance to the SRES allowance in the 2021–22 notified prices, which revealed an over-recovery of $0.308/MWh (0.0308 c/kWh) (Table 4).

Table 4 SRES over-recovery, 2021–22

	Period	*STP*		*Clearing house price ($/MWh)[a]*	*SRES cost ($/MWh)*	*Average SRES cost ($/MWh)*
		Final (%)	*Non-binding (%)*			
2021–22 final determination allowance	1 Jul–31 Dec 2021	28.80	–	40.00	11.520	11.520
	1 Jan–30 Jun 2022	–	28.80	40.00	11.520	
2021–22 actual cost	1 Jul–31 Dec 2021	28.80	–	40.00	11.520	11.212
	1 Jan–30 Jun 2022	27.26	–	40.00	10.904	
Over-recovery in 2021–22 (before adjusting for energy losses, time value of money, variable retail cost allocators and standing offer adjustment/headroom)						0.308

a Determined by the Clean Energy Regulator.

Calculate SRES costs to be passed through in the 2022–23 notified prices

We adjusted the over-recovery amounts (Table 4) for:

- energy losses (to determine the SRES liabilities based on energy acquired), by applying the relevant transmission and distribution loss factors adopted in the 2021–22 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 7.22 per cent[42]
- the variable retail cost allocators and standing offer adjustment (consistent with the manner in which these allowances were applied as part of the 2021–22 determination).

Once adjusted, the resulting pass-through amount was included in the notified prices (see Table 5).

[42] Based on our latest internal analysis.

Table 5 SRES pass-through amounts

Energex NSLP and controlled load profiles (CLPs)—residential and load control[a] tariffs		
A	SRES over-recovery in 2021–22 (c/kWh)	–0.0308
B	Energy losses in 2021–22 (total loss factor)	1.066
C	Discount rate (time value of money) (%)	7.22
D	Over-recovery before the application of standing offer adjustment and variable retail cost allowance (2022–23 c/kWh)	–0.0352
E	Variable retail cost allowance (residential) in 2021–22 (%)	7.25
F	Standing offer adjustment in 2021–22 (%)	3.6
G	SRES cost pass-through for 2022–23 (c/kWh)	–0.0391
Energex NSLP and CLPs—small business, load control[b] and unmetered supply tariffs		
A	SRES over-recovery in 2021–22 (c/kWh)	–0.0308
B	Energy losses in 2021–22 (total loss factor)	1.066
C	Discount rate (time value of money) (%)	7.22
D	Over-recovery before the application of standing offer adjustment and variable retail cost allowance (2022–23 c/kWh)	–0.0352
E	Variable retail cost allowance (small business) in 2021–22 (%)	18.70
F	Standing offer adjustment in 2021–22 (%)	3.6
G	SRES cost pass-through for 2022–23 (c/kWh)	–0.0433
Ergon NSLP—limited access obsolete[c] tariffs		
A	SRES over-recovery in 2021–22 (c/kWh)	–0.0308
B	Energy losses in 2021–22 (total loss factor)	1.062
C	Discount rate (time value of money) (%)	7.22
D	Over-recovery before the application of headroom and variable retail cost allowance (2022–23 c/kWh)	–0.0351
E	Variable retail cost allowance (small business) in 2021–22 (%)	18.70
F	Headroom allowance in 2021–22 (%)	0.0
G	SRES cost pass-through for 2022–23 (c/kWh)	–0.0416
Ergon NSLP and CLPs—large business, load control[d] and street lighting tariffs		
A	SRES over-recovery in 2021–22 (c/kWh)	–0.0308
B	Energy losses in 2021–22 (total loss factor)	1.062
C	Discount rate (time value of money) (%)	7.22
D	Over-recovery before the application of headroom and variable retail cost allowance (2022–23 c/kWh)	–0.0351
E	Variable retail cost allowance (large business) in 2021–22 (%)	6.0445
F	Headroom allowance in 2021–22 (%)	0.0

G	SRES cost pass-through for 2022–23 (c/kWh)	–0.0372
Ergon Energy NSLP—very large business tariffs		
A	SRES over-recovery in 2021–22 (c/kWh)	–0.0308
B	Energy losses in 2021–22 (total loss factor)	1.022
C	Discount rate (time value of money) (%)	7.22
D	Over-recovery before the application of headroom and variable retail cost allowance (2022–23 c/kWh)	–0.0337
E	Variable retail cost allowance (very large business) in 2021–22 (%)	6.0445
F	Headroom allowance in 2021–22 (%)	0.0
G	SRES cost pass-through for 2022–23 (c/kWh)	–0.0358

a Tariffs 31 and 33.

b Tariff 34.

c Tariffs 62A, 65A and 66A.

d Tariffs 60A and 60B.

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 F: 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 figure, 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 6 Median usage data used to determine customer impacts

Retail tariff	*Usage (kWh per year)*	*Demand (kW per month)*	*Demand threshold (kW per month)*
T11	4,296		
T31	1,674		
T33	1,549		
T20	6,580		
T44	139,334	46	30
T45	645,297	178	120
T46	1,403,325	465	400

APPENDIX G: BUILD-UP OF NOTIFIED PRICES

Table 7 Notified prices—residential customers (excl. GST)

Retail tariff	*Tariff component*	*Fixed[a]*	*Usage*			*Demand*	
			Off-peak/flat	*Shoulder*	*Peak*	*Off-peak/flat*	*Peak*
		c/day	*c/kWh*	*c/kWh*	*c/kWh*	*$/kW/mth*	*$/kW/mth*
Tariff 11—residential (flat-rate)	Network	51.600	7.437				
	Energy		12.501				
	Fixed Retail	35.582					
	Variable Retail		1.445				
	Standing offer adjustment	3.226	0.791				
	SRES cost pass-through		-0.0391				
	Total	**90.408**	**22.135**				
Tariff 12B—residential time-of-use	Network	51.600	3.031	3.670	14.450		
	Energy		12.501	12.501	12.501		
	Fixed retail	35.582					
	Variable retail		1.126	1.172	1.954		
	Standing offer adjustment	3.226	0.616	0.642	1.069		
	SRES cost pass-through		-0.0391	-0.0391	-0.0391		
	Total	**90.408**	**17.235**	**17.946**	**29.935**		
Tariff 14A—residential time-of-use demand	Network	51.600	3.591			3.418	
	Energy		12.501				
	Fixed retail	35.582					
	Variable retail		1.167			0.248	
	Standing offer adjustment	3.226	0.639			0.136	
	SRES cost pass-through		-0.0391				
	Total	**90.408**	**17.858**			**3.801**	
Tariff 14B—residential time-of-use demand	Network	51.600	2.576			7.121	
	Energy		12.501				
	Fixed retail	35.582					
	Variable retail		1.093			0.516	

Retail tariff	Tariff component	Fixed[a]	Usage			Demand	
			Off-peak/flat	Shoulder	Peak	Off-peak/flat	Peak
		c/day	c/kWh	c/kWh	c/kWh	$/kW/mth	$/kW/mth
	Standing offer adjustment	3.226	0.598			0.283	
	SRES cost pass-through		-0.0391				
	Total	**90.408**	**16.729**			**7.920**	
Tariff 31—night rate (super economy)	Network		3.371				
	Energy		10.777				
	Fixed retail						
	Variable retail		1.026				
	Standing offer adjustment		0.561				
	SRES cost pass-through		-0.0391				
	Total		**15.696**				
Tariff 33—controlled supply (economy)	Network		4.371				
	Energy		11.309				
	Fixed retail						
	Variable retail		1.137				
	Standing offer adjustment		0.622				
	SRES cost pass-through		-0.0391				
	Total		**17.400**				
Tariffs to be made obsolete from 1 July 2022							
Tariff 12A—residential (time-of-use)	Network	33.898	5.279		37.244		
	Energy		12.501		12.501		
	Fixed retail	35.582					
	Variable retail		1.289		3.607		
	Standing offer adjustment	2.571	0.706		1.974		
	SRES cost pass-through		-0.0391		-0.0391		
	Total	**72.051**	**19.736**		**55.287**		
Tariff 14—residential (seasonal	Network	6.971	2.197			6.433	44.796
	Energy		12.501				

Retail tariff	*Tariff component*	*Fixed[a]*	*Usage*			*Demand*	
			Off-peak/flat	*Shoulder*	*Peak*	*Off-peak/flat*	*Peak*
		c/day	*c/kWh*	*c/kWh*	*c/kWh*	*$/kW/mth*	*$/kW/mth*
time-of-use demand)	Fixed retail	35.582					
	Variable retail		1.066			0.466	3.248
	Standing offer adjustment	1.574	0.583			0.255	1.778
	SRES cost pass-through		-0.0391				
	Total	**44.127**	**16.308**			**7.155**	**49.821**

a *Charged per metering point.*

Note: Totals may not add due to rounding.

Table 8 Notified prices—small business and unmetered supply 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 20—business (flat-rate)	Network	69.000	8.176			
	Energy		12.501			
	Fixed retail	49.746				
	Variable retail		3.867			
	Standing offer adjustment	4.394	0.908			
	SRES cost pass-through		-0.0433			
	Total	**123.140**	**25.408**			
Tariff 24A—business (time-of-use demand)	Network	69.000	5.614		3.283	
	Energy		12.501			
	Fixed retail	49.746				
	Variable retail		3.387		0.614	
	Standing offer adjustment	4.394	0.796		0.144	
	SRES cost pass-through		-0.0433			
	Total	**123.140**	**22.255**		**4.041**	
	Network	69.000	4.614		8.444	
	Energy		12.501			

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 24B—business (time-of-use demand)	Fixed retail	49.746				
	Variable retail		3.200		1.579	
	Standing offer adjustment	4.394	0.752		0.371	
	SRES cost pass-through		-0.0433			
	Total	**123.140**	**21.024**		**10.394**	
Tariff 34—business (interruptible supply)	Network	59.800	4.438			
	Energy		11.140			
	Fixed retail	49.746				
	Variable retail		2.913			
	Standing offer adjustment	4.053	0.684			
	SRES cost pass-through		-0.0433			
	Total	**113.599**	**19.132**			
Tariff 91—unmetered	Network		5.883			
	Energy		12.501			
	Fixed retail					
	Variable retail		3.438			
	Standing offer adjustment		0.807			
	SRES cost pass-through		-0.0433			
	Total		**22.586**			
Tariffs to be made obsolete from 1 July 2022						
Tariff 22A—business (seasonal time-of-use)	Network	59.509	7.419	35.391		
	Energy		12.501	12.501		
	Fixed retail	49.746				
	Variable retail		3.725	8.956		
	Standing offer adjustment	4.042	0.875	2.103		
	SRES cost pass-through		-0.0433	-0.0433		
	Total	**113.298**	**24.476**	**58.907**		
	Network	7.453	2.863		6.121	60.918

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 24—business (seasonal time-of-use demand)	Energy		12.501			
	Fixed retail	49.746				
	Variable retail		2.873		1.145	11.392
	Standing offer adjustment	2.116	0.675		0.269	2.675
	SRES cost pass-through		-0.0433			
	Total	**59.315**	**18.868**		**7.535**	**74.985**
Tariff 41—business low voltage (demand)	Network	537.900	0.964		15.685	
	Energy		12.501			
	Fixed retail	49.746				
	Variable retail		2.518		2.933	
	Standing offer adjustment	21.743	0.591		0.689	
	SRES cost pass-through		-0.0433			
	Total	**609.389**	**16.531**		**19.307**	

a *Charged per metering point.*

Note: Totals may not add up precisely due to rounding.

Table 9 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	69.000	97.600	126.200	154.800	183.400	3.065	7.533	15.919
	Energy						12.501	12.501	12.501
	Fixed retail	49.746	49.746	49.746	49.746	49.746			
	Variable retail						2.911	3.746	5.315
	Standing offer adjustment	4.394	5.452	6.510	7.568	8.626	0.684	0.880	1.248
	SRES cost pass-through						-0.0433	-0.0433	-0.0433
	Total	**123.140**	**152.798**	**182.456**	**212.114**	**241.773**	**19.117**	**24.617**	**34.939**

a *Charged per metering point.*

Note: Totals may not add up precisely due to rounding.

Table 10 Notified prices—large business and street lighting customers (GST excl.)

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	3765.000	2.613		22.784		20.505	
	Energy		11.328					
	Fixed Retail	404.682						
	Variable Retail		0.843		1.377		1.239	
	Headroom							
	SRES cost pass-through		-0.0372					
	Total	**4169.682**	**14.747**		**24.161**		**21.744**	
Tariff 45—over 100 MWh medium (demand)	Network	12457.600	2.613		21.821		19.639	
	Energy		11.328					
	Fixed Retail	1113.140						
	Variable Retail		0.843		1.319		1.187	
	Headroom							
	SRES cost pass-through		-0.0372					
	Total	**13570.740**	**14.747**		**23.140**		**20.826**	
Tariff 46—over 100 MWh large (demand)	Network	32560.400	2.613		17.874		16.086	
	Energy		11.328					
	Fixed Retail	2831.802						
	Variable Retail		0.843		1.080		0.972	
	Headroom							

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*
	SRES cost pass-through		-0.0372					
	Total	**35392.202**	**14.747**		**18.954**		**17.058**	
Tariff 50A—large business time-of-use demand	Network	17147.400	2.681				14.018	2.804
	Energy		11.328					
	Fixed Retail	364.440						
	Variable Retail		0.847				0.847	0.169
	Headroom							
	SRES cost pass-through		-0.0372					
	Total	**17511.840**	**14.819**				**14.865**	**2.973**
Tariff 60A—large business flat-rate interruptible supply (primary)	Network	3765.000	10.819					
	Energy		11.240					
	Fixed Retail	404.682						
	Variable Retail		1.333					
	Headroom							
	SRES cost pass-through		-0.0372					
	Total	**4169.682**	**23.355**					
Tariff 60B—large business flat-rate interruptible supply (secondary)	Network		10.819					
	Energy		11.240					
	Fixed Retail							
	Variable Retail		1.333					

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		-0.0372					
	Total		**23.355**					
Tariff 71—street lighting	Network		15.490					
	Energy		11.328					
	Fixed Retail							
	Variable Retail		1.621					
	Headroom							
	SRES cost pass-through		-0.0372					
	Total		**28.402**					
Tariffs to be made obsolete from 1 July 2022								
Tariff 50—over 100 MWh seasonal time-of-use (demand)	Network	3146.400	4.705	1.146	10.266	67.375		
	Energy		11.328	11.328				
	Fixed Retail	364.440						
	Variable Retail		0.969	0.754	0.621	4.072		
	Headroom							
	SRES cost pass-through		-0.0372	-0.0372				
	Total	**3510.840**	**16.965**	**13.191**	**10.887**	**71.447**		

a *Charged per metering point.*

Note: Totals may not add up precisely due to rounding.

Table 11 Notified prices—very large business customers (GST excl.)

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	21762.300	1.578	6.385	3.463	3.316
	Energy		10.829			
	Fixed Retail	2803.175				
	Variable Retail		0.750	0.386	0.209	0.200
	Headroom					
	SRES cost pass-through		-0.0358			
	Total	**24565.475**	**13.122**	**6.771**	**3.672**	**3.516**
Tariff 51B—high voltage (CAC 33 kV)	Network	14774.800	1.578	6.385	4.230	3.435
	Energy		10.829			
	Fixed Retail	2803.175				
	Variable Retail		0.750	0.386	0.256	0.208
	Headroom					
	SRES cost pass-through		-0.0358			
	Total	**17577.975**	**13.122**	**6.771**	**4.486**	**3.643**
Tariff 51C—high voltage (CAC 22/11kV Bus)	Network	13564.500	1.578	6.385	4.879	4.165
	Energy		10.829			
	Fixed Retail	2803.175				
	Variable Retail		0.750	0.386	0.295	0.252
	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		-0.0358			
	Total	**16367.675**	**13.122**	**6.771**	**5.174**	**4.417**
Tariff 51D—high voltage (CAC 22/11kV Line)	Network	12872.900	1.578	6.385	9.457	8.400
	Energy		10.829			
	Fixed Retail	2803.175				
	Variable Retail		0.750	0.386	0.572	0.508
	Headroom					
	SRES cost pass-through		-0.0358			
	Total	**15676.075**	**13.122**	**6.771**	**10.029**	**8.908**
Tariff 53—high voltage (ICC)	Network	21762.300	1.578		3.463	3.316
	Energy		10.829			
	Fixed Retail	2609.455				
	Variable Retail		0.750		0.209	0.200
	Headroom					
	SRES cost pass-through		-0.0358			
	Total	**24371.755**	**13.122**		**3.672**	**3.516**
ICC site-specific—high voltage	Energy		10.829			
	Fixed Retail	2609.455				
	Variable Retail		0.750		0.209	0.200
	Headroom					
	SRES cost pass-through		-0.0358			

Retail tariff	***Tariff component***	***Fixed[a]***	***Usage***	***Connection unit***	***Capacity***	***Demand***
		c/day	***c/kWh***	***$/day/unit***	***$/kVA of AD/mth***	***$/kVA/mth***
	Total	**2609.455**	**11.544**		**0.209**	**0.200**

a *Charged per metering point.*

Table 12 Notified prices—very large business customers (GST excl.)

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	10019.900	1.681	0.919	6.385	5.995	12.901
	Energy		10.829	10.829			
	Fixed Retail	2803.175					
	Variable Retail		0.756	0.710	0.386	0.362	0.780
	Headroom						
	SRES cost pass-through		-0.0358	-0.0358			
	Total	**12823.075**	**13.231**	**12.423**	**6.771**	**6.357**	**13.681**
Tariff 52B—high voltage (CAC STOUD 22/11kV Bus)	Network	10019.900	1.681	0.919	6.385	4.236	44.200
	Energy		10.829	10.829			
	Fixed Retail	2803.175					
	Variable Retail		0.756	0.710	0.386	0.256	2.672
	Headroom						
	SRES cost pass-through		-0.0358	-0.0358			
	Total	**12823.075**	**13.231**	**12.423**	**6.771**	**4.492**	**46.872**
Tariff 52C—high voltage (CAC STOUD 22/11kV Line)	Network	10019.900	1.681	0.919	6.385	7.754	68.575
	Energy		10.829	10.829			
	Fixed Retail	2803.175					
	Variable Retail		0.756	0.710	0.386	0.469	4.145
	Headroom						

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
	SRES cost pass-through		-0.0358	-0.0358			
	Total	**12823.075**	**13.231**	**12.423**	**6.771**	**8.223**	**72.720**

a Charged per metering point.

Note: Totals may not add up precisely due to rounding.

Table 13 Notified prices—large business customers (GST excl.)

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	3765.000	2.614	11.048
	Energy		11.328	11.328
	Fixed Retail	404.682		
	Variable Retail		0.843	1.353
	Headroom			
	SRES cost pass-through		-0.0372	-0.0372
	Total	**4169.682**	**14.748**	**23.692**

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 14 Limited-access obsolete tariffs—small business customers (GST excl.)

Retail tariff	***Tariff component***	***Fixed***[a]	***Usage***			***Capacity***	
			Block 1/ Peak	***Block 2***	***Off-peak/flat***	***Up to 7.5kW***	***Over 7.5kW***
		c/day	***c/kWh***	***c/kWh***	***c/kWh***	***$/kW***	***$/kW***
Tariff 62A—time-of-use declining block tariff[b]	Network	56.100	39.253	31.238	5.689		
	Energy		11.328	11.328	11.328		
	Fixed Retail	50.084					
	Variable Retail		9.459	7.960	3.182		
	Headroom						
	SRES cost pass-through		-0.0416	-0.0416	-0.0416		
	Total	**106.184**	**59.998**	**50.485**	**20.158**		
Tariff 65A—time-of-use tariff[c]	Network	55.800	28.620		10.071		
	Energy		11.328		11.328		
	Fixed Retail	50.084					
	Variable Retail		7.470		4.002		
	Headroom						
	SRES cost pass-through		-0.0416		-0.0416		
	Total	**105.884**	**47.377**		**25.359**		
Tariff 66A—dual-rate demand tariff	Network	173.900			8.929	3.469	10.474
	Energy				11.328		
	Fixed Retail	50.084					
	Variable Retail				3.788	0.649	1.959
	Headroom						

Retail tariff	*Tariff component*	*Fixed[a]*	*Usage*			*Capacity*	
			Block 1/ Peak	***Block 2***	***Off-peak/flat***	***Up to 7.5kW***	***Over 7.5kW***
		c/day	***c/kWh***	***c/kWh***	***c/kWh***	***$/kW***	***$/kW***
	SRES cost pass-through				-0.0416		
	Total	**223.984**			**24.004**	**4.118**	**12.433**

a *Charged per metering point.*

b *Block 1—7am to 9pm on weekdays (first 10,000 kWh per month); Block 2—7 am to 9 pm on weekdays (remaining kWh per month); off-peak—all other times.*

c *Peak—a fixed 12 hour period as agreed between the retailer and customer from the range 7am to 7pm, 7.30am to 7.30pm or 8am to 8pm; off-peak—all other times.*

Note: Totals may not add up precisely due to rounding.

APPENDIX H: 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 11 June 2021.

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 Certificate of Delegation from the Minister for Energy, Renewables and Hydrogen (dated 16 December 2021) and sections 90 and 90AB of the Electricity Act, I hereby state that the Queensland Competition Authority decided that, on and from 1 July 2022, 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 day of MMMM 2022.

Flavio Menezes, Chair
Queensland Competition Authority

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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, 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 (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 kilovolt-amperes (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.

Tariff 22B

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.

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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 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.

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.

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,

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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	22.135	c/kWh
		Daily supply charge	90.408	c
12B	Residential time-of-use primary tariff	Usage:		
		Peak (4pm – 9pm)	29.935	c/kWh
		Day (9am – 4pm)	17.235	c/kWh
		Night (all other times)	17.946	c/kWh
		Daily supply charge	90.408	c
14A	Residential time-of-use monthly demand primary tariff.	Demand:		
		Peak (4pm – 9pm)	3.801	$/kW
		All other times	0.0	$/kW
		Usage	17.858	c/kWh
		Daily supply charge	90.408	c
14B	Residential time-of-use monthly demand primary tariff.	Demand:		
		Peak (4pm – 9pm)	7.920	$/kW
		All other times	0.0	$/kW
		Usage	16.729	c/kWh
		Daily supply charge	90.408	c
20	Small business flat-rate primary tariff.	Usage	25.408	c/kWh
		Daily supply charge	123.140	c
22B	Small business time-of-use inclining-band primary tariff.	Usage:		
		Peak (4pm – 9pm weekdays)	34.939	c/kWh
		Day (9am – 4pm)	19.117	c/kWh
		Night (all other times)	24.617	c/kWh
		Daily supply charge:		
		Band 1	123.140	c
		Band 2	152.798	c
		Band 3	182.456	c
		Band 4	212.114	c
		Band 5	241.773	c

Tariff	Description	Charge type	Rate	Unit
24A	Small business time-of-use monthly demand primary tariff.	Demand:		
		Peak (4pm – 9pm weekdays)	4.041	$/kW
		All other times	0.0	$/kW
		Usage	22.255	c/kWh
		Daily supply charge	123.140	c
24B	Small business time-of-use monthly demand primary tariff.	Demand:		
		Peak (4pm – 9pm weekdays)	10.394	$/kW
		All other times	0.0	$/kW
		Usage	21.024	c/kWh
		Daily supply charge	123.140	c
31	Small customer flat-rate secondary tariff with interruptible supply.	Usage	15.696	c/kWh
33	Small customer flat-rate secondary tariff with interruptible supply.	Usage	17.400	c/kWh
34	Small business flat-rate primary tariff with interruptible supply.	Usage	19.132	c/kWh
		Daily supply charge	113.599	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	14.748	c/kWh
		all remaining usage	23.692	c/kWh
		Daily supply charge	4169.682	c
44	Large business monthly demand primary tariff Demand threshold 30 kW / 35 kVA.	Chargeable demand; or	24.161	$/kW
		Chargeable demand	21.744	$/kVA
		Usage	14.747	c/kWh
		Daily supply charge	4169.682	c
45	Large business monthly demand primary tariff Demand threshold 120 kW / 135 kVA.	Chargeable demand; or	23.140	$/kW
		Chargeable demand	20.826	$/kVA
		Usage	14.747	c/kWh
		Daily supply charge	13570.740	c

Tariff	Description	Charge type	Rate	Unit
46	Large business monthly demand primary tariff Demand threshold 400 kW / 450 kVA.	Chargeable demand; or	18.954	$/kW
		Chargeable demand	17.058	$/kVA
		Usage	14.747	c/kWh
		Daily supply charge	35392.202	c
50A	Large business time-of-use monthly demand primary tariff.	Demand: Peak (4pm – 9pm weekdays)	14.865	$/kVA
		Excess	2.973	$/kVA
		Usage	14.819	c/kWh
		Daily supply charge	17511.840	c
51A	Large business high-voltage monthly demand primary tariff only for customers classified as CAC and supplied at 66kV.	Demand	3.516	$/kVA
		Capacity	3.672	$/kVA
		Usage	13.122	c/kWh
		Daily connection charge	6.771	$/unit
		Daily supply charge	24565.475	c
51B	Large business high-voltage monthly demand primary tariff only for customers classified as CAC and supplied at 33kV.	Demand	3.643	$/kVA
		Capacity	4.486	$/kVA
		Usage	13.122	c/kWh
		Daily connection charge	6.771	$/unit
		Daily supply charge	17577.975	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	4.417	$/kVA
		Capacity	5.174	$/kVA
		Usage	13.122	c/kWh
		Daily connection charge	6.771	$/unit
		Daily supply charge	16367.675	c

Tariff	Description	Charge type	Rate	Unit
51D	Large business high-voltage monthly demand primary tariff only for customers classified as CAC and supplied on an 11 or 22kV line.	Demand	8.908	$/kVA
		Capacity	10.029	$/kVA
		Usage	13.122	c/kWh
		Daily connection charge	6.771	$/unit
		Daily supply charge	15676.075	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	13.681	$/kVA
		Chargeable capacity	6.357	$/kVA
		Usage – Summer	12.423	c/kWh
		Usage – All other times	13.231	c/kWh
		Daily connection charge	6.771	$/unit
		Daily supply charge	12823.075	c
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	46.872	$/kVA
		Chargeable capacity	4.492	$/kVA
		Usage – Summer	12.423	c/kWh
		Usage – All other times	13.231	c/kWh
		Daily connection charge	6.771	$/unit
		Daily supply charge	12823.075	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	8.223	$/kVA
		Usage – Summer	12.423	c/kWh
		Usage – All other times	13.231	c/kWh
		Daily connection charge	6.771	$/unit
		Daily supply charge	12823.075	c
53	Large business high-voltage monthly primary tariff only for customers classified as ICC.	Demand	3.516	$/kVA
		Capacity	3.672	$/kVA
		Usage	13.122	c/kWh
		Daily supply charge	24371.755	c

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Tariff	Description	Charge type	Rate	Unit
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	0.200	$/kVA
		Capacity	0.209	$/kVA
		Usage	11.544	c/kWh
		Daily supply charge	2609.455	c
60A	Large business flat-rate primary tariff with interruptible supply.	Usage	23.355	c/kWh
		Daily supply charge	4169.682	c
60B	Large business flat-rate secondary tariff with interruptible supply.	Usage	23.355	c/kWh

Unmetered supply tariffs

Tariff	Description	Charge type	Rate	Unit
71	Business flat-rate primary tariff for street lighting.	Usage	28.402	c/kWh
91	Business flat-rate primary tariff.	Usage	22.586	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

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	74.985	$/kW
		Chargeable Demand – Off peak	7.535	$/kW
		Usage	18.868	c/kWh
		Daily supply charge	59.315	c
41	Obsolete small business monthly demand primary tariff. Scheduled phase-out date: 30 June 2023	Demand	19.307	$/kW
		Usage	16.531	c/kWh
		Daily supply charge	609.389	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	71.447	$/kW
		Off-peak chargeable demand	10.887	$/kW
		Peak usage	13.191	c/kWh
		Off-peak usage	16.965	c/kWh
		Daily supply charge	3510.840	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	59.998	c/kWh
		remaining	50.485	c/kWh
		Usage – all other times	20.158	c/kWh
		Daily supply charge	106.184	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)	47.377	c/kWh
		Usage – all other times	25.359	c/kWh
		Daily supply charge	105.884	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	4.118	$/kW
		Fixed charge (monthly) – remaining kW	12.433	$/kW
		Usage	24.004	c/kWh
		Daily supply charge	223.984	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	207.603	c
Standard asset customer (annual consumption greater than 750MWh)	Daily metering charge	249.175	c
Connection asset customer	Daily metering charge	429.569	c
Individually calculated customer	Daily metering charge	400.498	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