REVIEW OF THE APPROACH TO REGULATING RETAIL ELECTRICITY PRICES

DRAFT METHODOLOGY PAPER

JULY 2024

CONTACT DETAILS

Office of the Tasmanian Economic Regulator

Website:	www.economicregulator.tas.gov.au
Email:	office@economicregulator.tas.gov.au
Office hours:	8.45am to 5.00pm, Monday to Friday (except public holidays)
Street address:	Level 3, 21 Murray Street, Hobart, Tasmania 7000
Postal address:	GPO Box 770, Hobart, Tasmania 7001
Telephone:	(03) 6145 5899 or international +61 3 6145 5899

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Office of the Tasmanian Economic Regulator
Level 3, 21 Murray Street, Hobart TAS 7000
GPO Box 770, Hobart TAS 7001
Phone: (03) 6145 5899

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INVITATION TO MAKE SUBMISIONS

The Tasmanian Economic Regulator is seeking written submissions on this Draft Paper from interested parties by close of business **2 August 2024**.

Submissions do not need to address all of the issues referred to, or questions raised, in the Draft Paper. It is the Regulator's policy to publish all submissions on the Office of the Tasmanian Economic Regulator's (OTTER) website unless the author requests all or parts of the submission be kept confidential. Those parts of a submission requested to be kept confidential should be submitted as an attachment to the parts suitable for publication.

The Regulator will not publish submissions which contain material that the Regulator believes is, or could be viewed as, derogatory or defamatory.

Submissions and enquiries may be made to: office@economicregulator.tas.gov.au

If any assistance is required in preparing a submission, please contact OTTER at the above email address or by phone: (03) 6145 5899.

ISSUES FOR COMMENT

The Regulator is required to determine the maximum standing offer (regulated) prices that Aurora Energy can charge small customers in Tasmania on standard retail contracts[1] for the supply of electricity for the regulatory period commencing on 1 July 2025.

Before making a price determination, the Regulator must conduct a pricing investigation.

This draft paper is part of the investigation process. It reviews the approaches used in previous investigations, arrangements in other jurisdictions and sets out the Regulator's proposed approach for the next investigation and determination.

The Regulator is seeking interested parties' comments on the following matters:

Customer numbers

The Regulator is considering alternative methods to forecast customer numbers and is seeking comments from stakeholders on the method to be used.

Calculation of the wholesale electricity price (WEP)

The Regulator is seeking comments on the methods discussed in this paper and any other alternative methods for calculating the WEP.

Treatment of costs relating to Basslink

The Regulator is seeking comments on the treatment of costs relating to Basslink in the event that the Australian Energy Regulator (AER) decides that pricing of Basslink's services should be regulated.

Cost to serve (CTS)

The Regulator is seeking comments on its proposed approach to calculating Aurora Energy's CTS, in particular:

- removing the adjustment mechanism that takes account of changes in customer numbers; and
- the treatment of cloud-based software costs.

[1] Small customers are all residential customer and small business customers using less than 150MWh of electricity per annum.

Metering costs

The Regulator is seeking comments on a lower allowance for the recovery of metering costs and on refining the method for calculating the proportion of regulated customers and market customers on Tariffs 22, 31, 41, 75 and 94.

Retail margin

The Regulator is seeking comments on whether the retail margin should continue to be calculated on a dollar amount per customer basis or as a combination of a dollar amount per customer and a percentage of costs.

Treatment of unaccounted for energy (UFE)

The Regulator is seeking feedback on the treatment of UFE, which is the difference between metered energy entering a local area and the metered energy consumed within that local area.

Aurora Energy's Tariff Strategy

Subject to the magnitude of Aurora Energy's side constraints when seeking to adjust the fixed and variable components across its range of tariffs, should the Regulator consider other mechanisms to reduce customer impacts by introducing, for example, limits on the magnitude of the side constraints?

The Regulator is seeking feedback on Aurora's current approach to flat rate tariffs, with the grandfathering of existing standing offer flat rate tariffs and the introduction of a new contract flat rate tariff. In particular, the Regulator is seeking input on what information should be provided to customers so that they can understand and receive the benefit of a time-of-use tariff or determine if an alternative tariff is more suitable for their circumstances. Additionally, the Regulator is seeking feedback regarding whether there is a need for simpler tariffs.

Price approval process

The Regulator seeks feedback on its proposals to require Aurora Energy to consult with stakeholders on any tariff rebalancing proposals and on the Regulator publishing the WEP and Aurora Energy's draft pricing proposal as soon as practicable.

Length of regulatory period

The Regulator is seeking feedback on whether the next regulatory period commencing on 1 July 2025 should be of three or four years' duration.

OVERVIEW

This paper summarises the Regulator's proposed approach to determining the maximum standing offer (regulated) prices that Aurora Energy can charge small customers in Tasmania on standard retail contracts for the supply of electricity for the regulatory period commencing on 1 July 2025.

Before making a price determination, the Regulator is required to conduct a pricing investigation.

The Regulator's proposed approach for the 2025 Determination is summarised in Table 1. The Table also compares the proposed approach for estimating cost and input components to the current approach (2022 Determination).

This paper and the methodologies set out in it do not apply to the prices Aurora Energy's charges customers on market retail contracts, nor does it apply to the prices charged by other retailers offering market contracts in Tasmania.

Table 1: Comparison of current approach and proposed approach

Component	Current approach (2022 Determination)	Proposed approach for the 2025 Price Investigation and Determination
Overall approach	Cost build-up approach.	No changes are proposed.
Customer numbers	The forecast of customer numbers was based on the mid-point of the actual customer numbers on regulated tariffs as at 31 March of the year prior to the price period and 31 March in the price period.	The Regulator is considering alternative methods to forecast customer numbers.
Load	The forecast load for each price period was required to be consistent with the forecast customer numbers that apply for that price period.	No changes are proposed.
Wholesale electricity costs (WEC)	The WEC is based on the wholesale electricity price (WEP), forecast customer load adjusted for distribution and marginal loss factors.	No changes are proposed.
WEP	The WEP is calculated in accordance with the *Electricity Supply Industry Act 1995* and the	The Regulator is considering alternative methods to calculate the

	Standing Offer Price Approval Guideline. The WEP is calculated in late May.	WEP, including the timing of the WEP calculation.
Network costs	Network costs were calculated by multiplying the AER's approved network tariffs by forecast billing days and customer load for each retail tariff, for the applicable period, and then summing the resultant values. Billing days used in deriving network costs reconciled with the forecast of the customer numbers used in the Notional Tariff Base.	While the proposed approach remains unchanged, the Regulator is considering the treatment of costs relating to Basslink.
Cost to serve	A per customer CTS amount was derived using a combination of bottom up and benchmarking approaches. The calculation also included: ▪ an efficiency factor; ▪ a mechanism to reflect changes to Aurora Energy's customer numbers; and ▪ indexing labour cost components by the Tasmanian Wage Price Index and all other components by the Hobart CPI.	The Regulator intends adopting a similar approach, except that the Regulator proposes: ▪ removing the mechanism that takes account of changes in customer numbers; ▪ further consideration of the treatment of cloud-based software costs including decisions made by other regulators with respect to these costs; and ▪ Aurora Energy implementing a cost allocation manual prior to the pricing investigation.
Renewable energy target (RET) costs	Aurora Energy's long term contractual commitments under the Cattle Hill Power Purchase Agreement were included in Aurora Energy's cost allowance for Large-scale Generation Certificates (LGCs). The forward price for the remaining LGCs in the relevant year were estimated as the average weekly forward LGC price over 12 months of the previous year. The Clean Energy Regulator's Small-scale Technology Percentages were used to calculate Small-scale Renewable Energy Scheme costs.	No changes are proposed.

Metering costs	In estimating costs for metering services, the Regulator used a weighted average cost of meters by tariff applied to the notional tariff base (NTB). The Regulator also allowed Aurora Energy to recover depreciation (over six years) with respect to the capital costs incurred due to the introduction of metering competition; depreciation in relation to Type 6 meters with a remaining useful life that are replaced with advanced meters; and fee-based metering services.	While the overall proposed approach remains unchanged, the Regulator is considering: ▪ a lower allowance for the recovery of metering costs that is in line with the Australian Energy Market Commission's recommendation of universal uptake of advanced meters by 2030; and ▪ refining the method for calculating the proportion of regulated customers and market customers on Tariffs 22, 31, 41, 75 and 94.
Retail margin	During the 2022 price investigation the Regulator adopted a benchmarking approach to setting Aurora Energy's retail margin and calculated it on a $/customer basis.	While the Regulator proposes to continue to use a benchmarking approach, the Regulator is seeking feedback on whether the margin should continue to be calculated on a $/customer basis or as a combination of a $/customer and percentage of costs basis.
Australian Energy Market Operator (AEMO) costs	AEMO costs were estimated by applying AEMO's draft published fees and charges and a forecast of ancillary charges for the relevant period to the NTB.	No changes are proposed.
Adjustments for under and over recoveries	The difference between forecast and actual costs for each period were passed through to small customers in the next period. Under and / or over recoveries are limited to network costs, metering costs, RET costs and AEMO charges.	The Regulator is considering whether costs related to UFE should be included as an adjustment.

1 INTRODUCTION

The *Electricity Supply Industry Act 1995* (the ESI Act) requires the Regulator to determine the maximum prices that Aurora Energy may charge small customers under standard retail contracts. Under the Act, Aurora Energy proposes, and the Regulator considers for approval, standing offer (regulated) electricity prices. Further details on the legislative framework are contained in Appendix 2.

The current price determination, *Aurora Energy Pty Ltd 2022 Standing Offer Price Determination* (2022 Determination), expires on 30 June 2025 and the Regulator is required to make a new price determination that will cover the regulatory period commencing on 1 July 2025. Before making the new price determination, the Regulator is required to conduct a pricing investigation.

This draft paper is part of the investigation process. It reviews the approaches used in previous investigations, arrangements in other jurisdictions and sets out the Regulator's proposed approach for the next investigation and determination. This is predicated on any future legislative changes not requiring the Regulator to adopt a different approach to setting standing offer prices.

This draft paper does not consider Aurora Energy's costs nor set standing offer electricity prices from 1 July 2025. Rather, this paper deals only with the methodology to be used for assessing the efficiency of Aurora Energy's costs and determining the resultant maximum prices for the regulatory period commencing on 1 July 2025.

1.1 Tasmanian retail electricity market

On 1 July 2014, full retail competition was introduced on mainland Tasmania, enabling retailers other than Aurora Energy to offer products to residential and small business customers. As of June 2024, six retailers supplied electricity to residential customers and eight retailers supplied electricity to small business customers in Tasmania.

The purpose of regulated prices is to provide a safety net price for customers and, in Tasmania, regulated prices are the maximum prices Aurora Energy can charge small customers under a standard retail contract. Tasmanian customers may receive their electricity supply under either a standard retail contract or a market retail contract.

Aurora Energy, the sole regulated retailer in Tasmania, is the dominant retailer with approximately 94 per cent of both residential and small business customers.[2] Of these customers, almost all residential customers and 88 per cent of small business customers receive their electricity supply via standard retail contracts.

The Regulator's objectives under the ESI Act in regulating Aurora Energy's standing offer prices include promoting efficiency and competition while at the same time protecting the interests

[2] Tasmanian Economic Regulator, *Energy in Tasmania Report 2022-23*, March 2024, p ii.

of electricity consumers. In balancing these objectives, the Regulator is mindful of ensuring that prices do not restrict competition but are set at a level which reflect efficient costs.

1.2 Next steps and timeline

After considering feedback on this paper, the Regulator will release a final paper in August 2024. The final paper will set out the approach the Regulator will apply in the 2024-25 pricing investigation and determination.

During the pricing investigation, the Regulator will issue and consult on a draft investigation report, a draft determination and a draft standing offer price approval guideline. The Regulator will also consult on Aurora Energy's draft standing offer tariff strategy.

Table 2 sets out the timeline for this paper and for the upcoming pricing investigation.

Table 2: Timeframes for methodology review and investigation and determination

Description of task	Anticipated due date
Regulator releases draft Methodology Paper	5 July 2024
Consultation on draft Methodology Paper closes	2 August 2024
Regulator releases final Methodology Paper	September 2024
Regulator releases Notice of Intention to conduct a pricing investigation	September 2024
Aurora Energy lodges its preliminary submission and its draft tariff strategy	15 October 2024
Regulator releases its draft report, draft price determination, draft standing offer price approval guideline and Aurora Energy's draft tariff strategy for public consultation	21 February 2025
Consultation on the Regulator's draft report, draft price determination, draft standing offer price approval guideline and Aurora Energy's draft tariff strategy closes	21 March 2025
Regulator releases its final report, final price determination and final standing offer price approval guideline and approves Aurora Energy's tariff strategy	2 May 2025
Aurora Energy submits its pricing proposal for 2025-26 to the Regulator for approval	31 May 2025
Regulator approves 2025-26 standing offer prices (consistent with the final price determination)	Prior to 1 July 2025

2 DETERMINING MAXIMUM PRICES

2.1 Background

Regulated prices are set at a level that enables Aurora Energy to recover the costs of supplying electricity to customers on standard retail contracts. These costs include:

- wholesale electricity costs;
- network costs;
- Aurora Energy's efficient retail costs (cost to serve);
- renewable energy target (RET) costs;
- metering costs; and
- other costs, such as AEMO costs.

In addition to these costs, a retail margin is applied to reflect the risks Aurora Energy incurs in providing retail services to small customers under standard retail contracts.

Other inputs used in the calculation of these components are loss factors, forecast customer numbers and forecast total load (together the latter two inputs are referred to as the Notional Tariff Base).

In past investigations, the Regulator has set maximum prices using a cost-build up approach. Under this approach, each component is summed to arrive at a total value of forecast costs for the year which is referred to as the Notional Maximum Revenue (NMR). The NMR is calculated solely for the purpose of determining maximum prices based on the forecasts included in the NTB. As the NMR relates only to Aurora Energy's regulated costs, the NMR is not able to be reconciled to the figures reported in Aurora Energy's financial statements.

The cost build-up approach is used by other regulators to regulate electricity prices and is a well-established and accepted approach. Furthermore, the individual cost components are generally consistent across jurisdictions which is useful for comparisons.

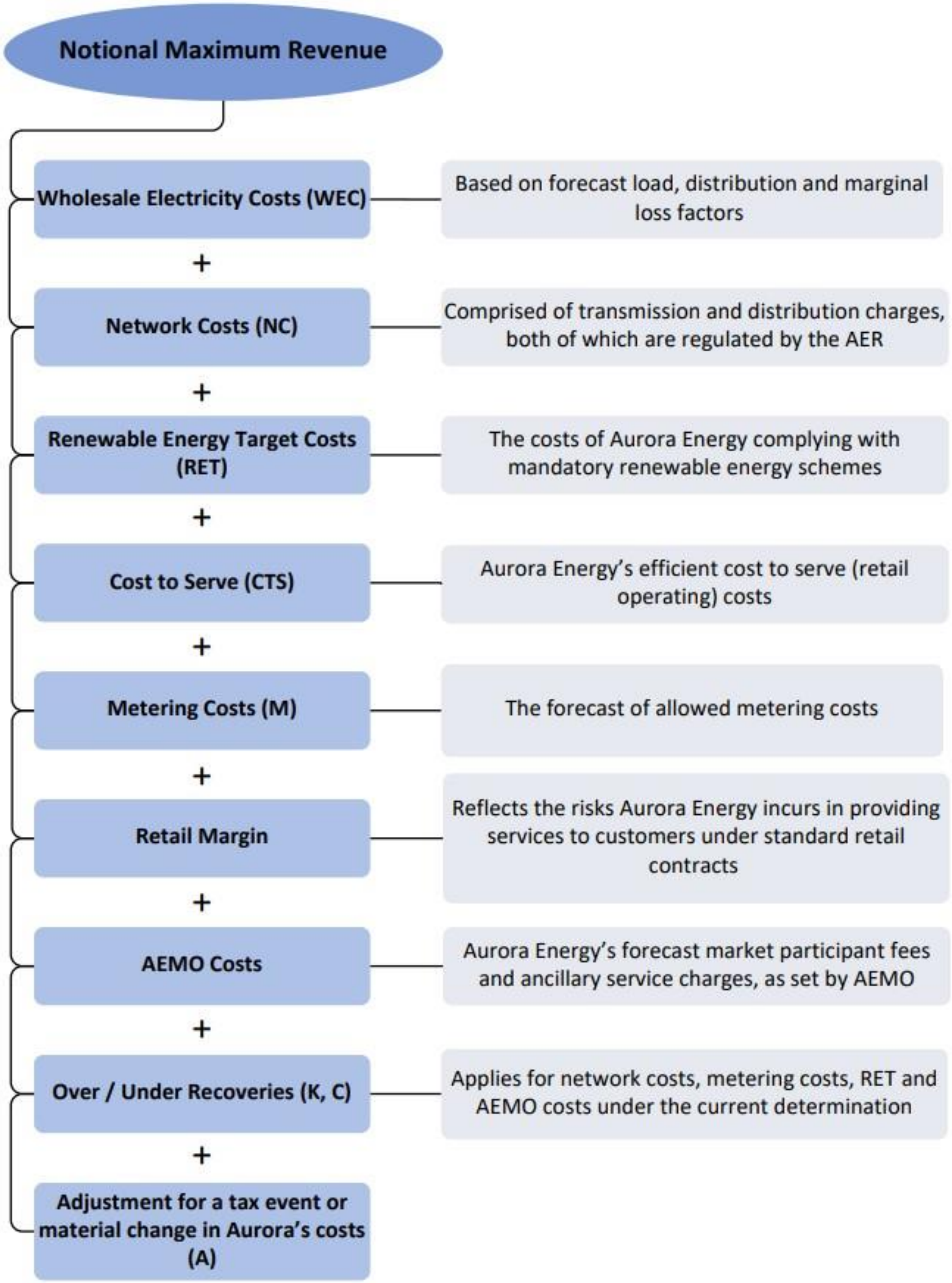
It is by examining these cost components that the Regulator seeks to ensure that standing offer customers do not pay more than necessary for the services they receive.

2.2 Calculating the NMR

The current formula for calculating the NMR, as set out in the 2022 Determination, is as follows:

$$NMR = WEC + NC + RET + CTS + M + MARGIN + AEMO + K + C + A$$

Figure 1: Cost components used to calculate the NMR



2.3 NMR cost components in 2024-25

The cost components that made up the NMR for 2024-25 are set out in Table 3.

Table 3: NMR cost components in 2024-25

Component	Cost ($)	Contribution to the NMR (%)
Wholesale Electricity Costs	197 655 289	32.21
Network Costs	254 422 203	41.47
Renewable Energy Target Costs	40 033 501	6.52
Cost to Serve	45 515 854	7.42
Metering Costs	38 824 583	6.33
Retail Margin	30 445 834	4.96
AEMO Costs	6 140 355	1.00
Aggregate Over / Under Recoveries	536 274	0.09
Total*	613 573 893	100

* Totals may not be exact due to rounding.

2.4 Other inputs

In the 2022 Determination, the Regulator approved the forecast of customer numbers as being the mid-point of actual customer numbers as at 31 March prior to the start of each year and a forecast of customer numbers as at 31 March during the year. Billing days, which refers to the number of days that a tariff is used by customers within a financial year, for network costs and metering costs, were reconciled to this forecast of customer numbers.

The Regulator also determined that the load in the NTB would be a forecast of the total amount of electricity consumed by the forecast number of customers over the 12-month period from 1 April to the following 31 March.

For the 2025 determination, the Regulator considers that the forecast of customers numbers could be more transparent. For example, the forecast of customer numbers during the year could be based on the average rate of growth or decline in actual customer numbers from the previous five years. There may also be other options to consider.

2.5 Proposed approach

The Regulator intends to continue to use a building block approach to set maximum standing offer prices. However, the Regulator is considering alternative methods to how customer numbers are forecast.

The Regulator is seeking comments from stakeholders on how customer numbers are forecast.

3 WHOLESALE ELECTRICITY COSTS

3.1 Background

Under the 2022 Determination, the estimate of the wholesale energy costs (WEC) component of the NMR is based on the wholesale electricity price (WEP), forecast customer load and distribution and marginal loss factors.

Hydro Tasmania is the dominant generator in Tasmania and controls the majority of the generation capacity in the State. Consequently, Hydro Tasmania is the sole provider of financial hedge contracts for the Tasmanian region of the NEM. In response to perceptions about Hydro Tasmania's market power, the Tasmanian Government has, since 2014, required Hydro Tasmania to offer regulated wholesale financial contracts at regulated prices to authorised retailers operating in Tasmania.

The ESI Act requires Hydro Tasmania to offer four financial risk contract types, approved by the Regulator, with the objective of providing retailers in Tasmania with similar conditions and levels of risk as faced by retailers operating in other regions of the NEM. The details of each approved financial contract type, including how prices are calculated, are specified in the *Wholesale Contract Regulatory Instrument* (Instrument). The Instrument documents a rule-based methodology for calculating the prices for each contract type in the wholesale pricing model.

The approved contract types include a load following swap (LFS). The effect of section 40AB(3) of the ESI Act, as it applies over the next regulatory period, is that Aurora Energy's WEP and therefore its WECs are based on LFS prices.

3.2 Current approach

3.2.1 The wholesale electricity price

In past determinations, the Regulator recognised that a retailer adopting a prudent hedging approach is likely to progressively build its contract book over a period of time and therefore developed a weighted average method for calculating the single WEP to apply for a year.

The method applied for the 2022 Determination used the weekly regulated LFS price[3] and is set out in Clause 4.1 of the Regulator's standing offer price approval guideline.[4]

3.2.2 Loss factors

As electricity flows through the transmission and distribution systems, a portion is lost due to electrical resistance and the heating of conductors. Due to these losses, the amount of electricity generated must be greater than actual demand. To account for the difference between the demand for electricity (load) and the amount of electricity generated to meet that demand, the load is multiplied by one or more loss factors.

The distribution loss factor (DLF) represents the average energy loss incurred when electricity is transmitted over the distribution network. Distribution Network Service Providers determine the DLFs to apply in each financial year and, after approval from the AER, provide the DLFs to AEMO for publication. AEMO is required to publish DLFs by 1 April each year to apply to the following financial year.

The marginal loss factor (MLF)[5] represents the average energy loss incurred when electricity is transmitted over the transmission network. AEMO determines and publishes MLFs for each NEM region in late May / early June each year. These published rates apply for the following financial year.

3.2.3 Load

The load used to calculate the WEC is based on the forecast customer demand for each tariff for the price period.

3.2.4 Calculating the WEC

The Regulator currently calculates the WEC as follows:

$$WEC_y = (\text{forecast load}_y \times WEP_y \times DLF_y \times MLF_y)$$

Where:

forecast load$_y$	=	an estimate of the volume of electricity a retailer must purchase in the spot market to supply small customers for period$_y$

3 The Load Following Swap (LFS) is one of the four wholesale electricity contract types approved under the Wholesale Contract Regulatory Instrument. The LFS sets the price that Tasmanian electricity retailers purchase a certain amount of electricity in a given future quarter of the year under a certain time interval of the day. The LFS therefore differs from the electricity spot price.

4 Tasmanian Economic Regulator, *Guideline - Standing Offer Price Approval Process in accordance with the 2022 Standing Offer Electricity Price Determination* (29 April 2022).

5 Also referred to as the TLF (Transmission Loss Factor).

WEP_y	=	wholesale electricity price for $period_y$ as calculated by the Regulator using the method set out in the Standing Offer Price Approval Guideline
DLF_y	=	load weighted average distribution loss factor for $period_y$
MLF_y	=	load weighted average marginal loss factor at the regional reference node for Tasmania for $period_y$

3.2.5 Impact of Wholesale Contract Regulatory Instrument investigation

On 26 June 2024, the Regulator released a final report from its 2023-24 *Wholesale Contract Regulatory Instrument Pricing Investigation*. During the investigation the Regulator considered and consulted on a number of issues including:

- Victorian peak future contract availability;
- open interest of Victorian peak futures contracts;
- calculation of the Maximum Baseload $300 Cap Contract Price;
- volume of regulated contracts and scaling process; and
- frequency for changing Basslink capacity values.

The outcomes from the investigation have been incorporated into the approvals and the Wholesale Contract Regulatory Instrument and will therefore flow through to the calculation of the weekly LFS and, in turn, the WEP for the next regulatory period.

3.3 Timing of the WEP calculation

During the current regulatory period, the Regulator has calculated the WEP in accordance with the method outlined in Clause 4.1(1) of the Guideline. Under this method, the Regulator is required to calculate the WEP in late May and provide the price to Aurora Energy on or before 24 May each year.

In conducting this review, the Regulator noted that the WEP calculated in May 2022 for inclusion in 2022-23 standing offer prices was materially higher than the WEP that would have been calculated for 2022-23 if it had been calculated in April 2022. As part of this methodology review, the Regulator has carried out further analysis to ascertain whether the timing of the WEP calculation could potentially have an impact on the WEP for the following year.

3.4 What other regulators do

To estimate future wholesale electricity costs in their respective cost build-ups, each of the Essential Services Commission (ESC), the AER, the Independent Competition and Regulatory Commission (ICRC), and the Queensland Competition Authority (QCA) use an electricity futures market-based approach and engage consultants to assist with this task. For example, the ICRC estimates energy purchase costs by calculating the average of NSW electricity futures prices, plus an uplift factor that compensates for the spot price volatility risk in the NEM. To date, the ESC and ICRC engage Frontier Economics, while the AER and QCA have engaged ACIL Allen to assist with forecasting these costs.

In calculating wholesale electricity prices for 2023-24, each regulator used the ASX listed contract price as follows:

- ESC used trade weighted ASX Energy contract prices from the previous 12 months, with prices as at the last Friday in April used as the final price.
- AER and QCA used trade weighted average ASX Energy daily settlement prices from the date the contract was listed until 10 May 2023.
- ICRC used the 23-month average of ASX Energy forward prices from 1 June 2021 to 30 April 2023.

In summary, regulators in other jurisdictions estimate wholesale electricity prices for the following year earlier than the Regulator currently does in Tasmania.

3.5 The Regulator’s analysis

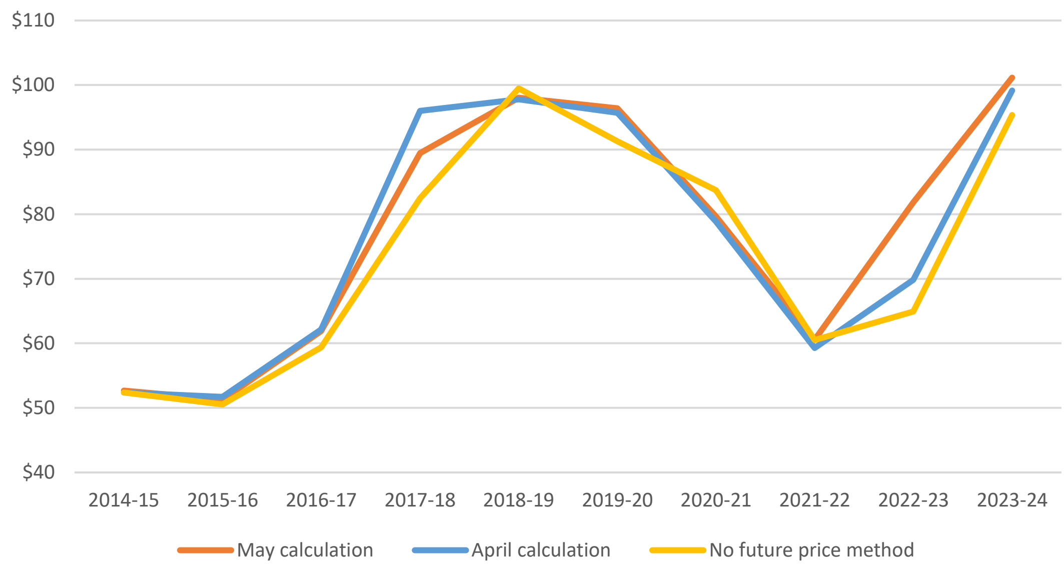
In assessing whether the timing of the WEP calculation influences the WEP for the following year, the Regulator assessed three approaches:

1. May calculation - the current method;
2. April calculation - using the last Tuesday in April as the cut-off point to calculate the WEP for the following year; and
3. No future price method - the current method except that both the LFS contract price and Absolute Minimum Capacity Offer volume for all weeks after the WEP calculation date are set to zero.

To assess the impact of these three approaches, the Regulator re-calculated the WEP under each method between 2014-15 and 2023-24. The results are set out in Figure 1.[6]

[6] Between 2017-18 and 2019-20, for the purpose of consistency, the WEP in Figure 1 assumes that no WEP Order was in place. In these three years, the WEP Order constrained the WEP so that the increase in the standing offer price was no higher than the rate of change in the Hobart CPI. This meant that the published WEP in these years was lower than the WEP calculated under the method explained in section 3.2.1.

Figure 2: Historical WEP values for 2014-15 to 2023-24 under alternative methods



With the exception of 2017-18 and 2022-23, the WEP calculated under the May and April calculation methods are closely aligned. In comparison, the no future price method tends to result in the WEP, on average, being lower than under the other two methods for the past 10 years.

Table 4 shows the average WEP over the last 10 years under each method and the estimated impact on retail electricity prices.[7]

Table 4: The average WEP between 2014-15 and 2023-24 under the three methods

	May calculation	April calculation	No future price method
Average WEP	$77.29	$76.28	$74.01
Change in the WEP compared to the current method		-1.30%	-4.25%
Indicative retail price change compared to price under the current method		-0.42%	-1.41%

The April calculation method and the no future price method result in a lower average WEP, holding everything else equal. If an April calculation method had been used over the past 10 years between 2014-15 and 2023-24, the retail price may have been 0.42 per cent lower on average in each year over this period. If using the no future price method, the retail price may have, on average, been lower by 1.41 per cent in each year of this period.

7 The Regulator re-calculated the indicative retail price change for each year between 2014-15 and 2023-24 and calculated the change in retail price compared to the current method. The estimated retail price impact is an indicative figure only and does not necessarily mean that retail prices would be lower in the future under a different approach.

Importantly, the calculation of the WEP using the April calculation method and the no future price method is significantly different from the May calculation method in two years:

- In 2017-18, the May calculation method results in a much lower WEP than the April calculation due to supply uncertainty in the mainland NEM regions, stemming from multiple events occurring between January and April 2017[8]. The LFS contract price decreased in May 2017. The No future price method is much lower than the May method in this period.
- In 2022-23, the May calculation method resulted in a much higher WEP than the other methods due to a significant increase in wholesale contract prices in May triggered by a reduction in thermal generation in the mainland, and an increasingly "peaky" demand[9].

To account for the abnormal events in these two years, the Regulator also analysed the average WEP and retail price under the proposed methods between 2014-15 and 2023-24, after excluding the pricing data for 2017-18 and 2022-23.

Table 5: The average WEP under different approaches from 2014-15 to 2023-24, excluding 2017-18 and 2022-23 data

	May calculation	April calculation	No future price method
Average WEP	$75.20	$74.62	$74.09
Change in the WEP compared to the current method		-0.77%	-1.48%
Indicative retail price change compared to price under the current method		-0.25%	-0.46%

After removing pricing data for 2017-18 and 2022-23, the reduction in WEP and retail prices becomes less compared to Table 4. In particular, the decrease in retail prices using the April calculation method is estimated to reduce by 0.25 per cent over this period instead of 0.42 per cent, while retail prices using the No future price method are estimated to reduce by 0.46 per cent over this period compared to 1.41 per cent.

3.6 Draft assessment

The Regulator considers that each of the options analysed have the objective of developing a method that calculates the WEP in the upcoming year as accurately as possible.

The main advantage of the April calculation method is that it adopts a cut-off date similar to other jurisdictions. Keeping other factors unchanged, if the April calculation method was used in the last 10 years, retail electricity prices on average would have been lower.

The advantage of the No future price method is that it does not try to forecast the unknown LFS contract price for future weeks. If this method had been applied over the past 10 years,

[8] Tasmanian Economic Regulator, Energy in Tasmanian Report 2016-17, page 7.

[9] Australian Energy Regulator, Default Market Offer Prices 2022-23 Final Determination, May 2022, page 2.

retail prices on average would have been lower again compared with the April calculation method.

However, as shown in Figure 2, the WEP is volatile and the estimated WEP under each method is not always higher or lower than the current method over the past 10 years. Hence the estimated retail price impact is indicative only and does not necessarily mean that retail prices would be lower in the future under a different approach.

In addition, the Regulator acknowledges that there is no perfect method for estimating the WEP and there may be other methods that have not been discussed in this paper, such as a combination of using an April calculation date and setting the LFS contract price for all future weeks to zero.

The Regulator is seeking comments from stakeholders on the three methods analysed and any other, alternative methods, for calculating the WEP.

4 NETWORK COSTS

4.1 Background

Network costs comprise transmission use of system and distribution use of system charges.

Network costs are regulated by the AER. The AER reviews and approves TasNetworks' transmission revenue and distribution regulatory revenue every five years, with the upcoming regulatory period being 2024-29. The AER will also review and approve TasNetworks' schedule of tariffs each year for compliance with the National Energy Rules (NER) and the five-year regulatory determination. The approved tariffs apply for 12 months from 1 July of each year and are usually set in April or May of the previous year.

Network tariffs comprise a fixed daily charge, consumption charges and, for some tariffs, a demand-based charge. Network tariffs are grouped by network tariff class, which are based on the physical characteristic of the electricity connection (e.g. high voltage) or customer type (e.g. residential or business).

4.2 Current approach

The network cost component of Aurora Energy's NMR is determined by multiplying the applicable TasNetworks' network tariff by forecast billing days and customer load for each retail tariff and then summing the resultant values. The billing days are then reconciled with the forecast of the customer numbers used in the NTB.

If for some reason the charges are not known when the NMR is calculated (e.g. if the AER did not approve TasNetworks' charges in time for Aurora Energy to incorporate the approved charges in its annual pricing proposal), network costs will be based on an estimate of the charges (e.g. based on TasNetworks' draft price proposal) for the next year and then an adjustment will be made in the subsequent year for any difference between the estimated and the actual charges.

4.3 What other regulators do

The approach taken by the ICRC, ESC and QCA in relation to network costs is to pass through the network costs to retailers as calculated by the AER each year.

ESC and ICRC allow for adjustments in subsequent periods for these costs where the pass-through costs are based on an estimate at the time of setting prices. Only the ICRC allows for an adjustment to network costs to allow for a different tariff mix during the price period compared to the forecast.

ICRC

The ICRC calculates a per MWh network cost by applying the AER approved network tariffs and prices to customer numbers and electricity consumption for the previous 12 months to 31 March each year.

QCA

The QCA sets retail tariffs to apply in regional Queensland and uses the applicable network prices approved by the AER in determining regulated retail prices:

- For small customers on standard retail tariffs, network costs are based on the costs of supply in Southeast Queensland (Energex distribution area).
- For large customers and small customers on limited access obsolete tariffs, network costs are based on the costs of supply on Ergon Distribution's lowest cost region that is connected to the NEM.

ESC

The approach used in the ESC's Victorian Default Offer varies depending on the distribution zone. The regulated electricity prices in each zone include network prices approved by the AER for the distribution network service provider in that zone. The ESC structures the network costs in one of two ways:

- Flat Network Tariffs: a daily supply charge ($ per day) and a flat usage charge ($ per kWh); or
- Two-period time of use network tariffs: a daily supply charge and peak usage and off-peak usage charge.

4.4 Treatment of costs relating to Basslink

Hydro Tasmania entered into a network services agreement with Basslink Pty Ltd (Basslink) on 21 October 2022.[10] The agreement expires on the earlier of 30 June 2025 or the day Basslink is regulated (unless extended by mutual agreement between Hydro Tasmania and Basslink). The payments made under this agreement are currently unregulated and these costs, therefore, are not currently part of Aurora Energy's NMR.

On 19 May 2023, APA Group, Basslink's current owner, applied to the AER for approval of a five-year regulatory control period from 1 July 2025 to 30 June 2030 with respect to the regulation of Basslink's services.[11] Specifically, APA:

- proposed converting Basslink's network services from a market network service provider to a prescribed transmission service provider; and
- requested AER commence, and specify, the process of making a transmission determination for Basslink.

In the event that the AER approves APA's proposal, the costs associated with transmission services provided by Basslink could be passed on to small consumers in Tasmania via their

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[10] Hydro Tasmania, Updated Basslink agreement (hydro.com.au), 24 October 2022.

[11] Australian Energy Regulator, Basslink Conversion Application and Electricity Transmission Determination, November 2023; APA Group, Basslink Transmission Revenue Proposal Attachment 4: Revenue and Pricing Methodology, 15 September 2023, page 114.

retailer. In its submission to the AER, APA proposed that these costs would be over $100 million per annum. APA engaged with consumers and stakeholders on their preferences for three potential revenue allocation methods. As a result of its engagement, APA proposed that 90 per cent of the costs be apportioned to Victorian and 10 per cent to Tasmanian customers based on the number of electricity connections in each region. This approach would result in an estimated increase of $8 in network charges for Tasmanian residential customers per year and an estimated increase of $15 for Tasmanian small business customers.

Section 40AB(4) of the ESI Act states that:

> For the purposes of this section, the transmission and distribution costs of the regulated offer retailer in relation to the provision of standard retail services consist of –
>
> (a) the prices, as determined in accordance with any relevant distribution determination made under the National Electricity Rules, charged to the regulated offer retailer for the distribution of electricity; and
>
> (b) the prices, as determined in accordance with any relevant transmission determination made under the National Electricity Rules, charged to the regulated offer retailer for the transmission of electricity –
>
> but only in so far as the costs relate to electricity used in the provision of standard retail services.[12]

The Regulator interprets that the intent of this section is to ensure Aurora Energy only recovers from customers paying standing offer prices the costs associated with providing retail electricity services to those customers.

In assessing whether the costs from Basslink relate to providing retail electricity services to customers paying standing offer prices under standard retail contracts, the Regulator notes that in the 2022-23 water year (from 1 November 2022 to 31 October 2023), the total electricity consumption in Tasmania was 10 879 GWh, with Basslink imports contributing 1 654 GWh or 15.2 per cent of that total.

There are a number of other factors to consider in assessing whether the costs from Basslink relate to providing electricity services to regulated customers, such as:

- the proportion of Basslink imports that are likely to be consumed by regulated customers compared to non-regulated customers, such as major industrials;
- Basslink's use by Hydro Tasmania as part of its trading strategy; and
- from an energy security perspective, Basslink can provide supplementary energy during periods with extremely low rainfall and low water storage levels.

[12] Standard retail services, in relation to a regulated offer retailer, means services to be provided by the retailer under standard retail contracts in respect of small customers.

4.5 Proposed approach

The Regulator proposes continuing with the current approach to forecasting network costs.

The Regulator is seeking comments from stakeholders on the treatment of costs relating to Basslink and the proportion of these regulated network costs that should be passed through to regulated customers.

5 COST TO SERVE

5.1 Background

Aurora Energy's CTS accounts for the operating costs it incurs providing retail services to small customers under standard retail contracts. Aurora Energy's CTS currently includes costs relating to:

- billing and revenue collection;
- marketing;
- providing advice and answering customer queries via its customer call centre;
- the aurora+ app;
- corporate overheads;
- allowance for bad debts; and
- regulatory compliance.

The current CTS allowance is expressed as a dollar per customer amount.

5.2 Current approach

During the 2022 Standing Offer Electricity Price Investigation, the Regulator used a combination of a cost build-up and benchmarking approach in determining Aurora Energy's CTS allowance for the regulatory period. This involved conducting a detailed review of Aurora Energy's operating cost structure to calculate what the Regulator considers to be an efficient CTS figure and then testing the result against CTS allowances for retailers in other Australian jurisdictions.

The Regulator also engaged consultants to review the efficiency of Aurora Energy's proposed CTS. A key recommendation from the consultant's work was for the Regulator to apply an efficiency factor to all components of the CTS. Based on information provided by the Australian Competition and Consumer Commission (ACCC), the consultants calculated an efficiency factor to reflect the decline in retail costs of retailers in other jurisdictions over the 2017 to 2021 financial years[13].

The Regulator also incorporated several adjustments in the CTS calculation formula. These adjustments included a mechanism to reflect changes to Aurora Energy's customer numbers, indexing labour cost components by the Tasmanian Wage Price Index and all other components by the Hobart CPI.

[13] ACCC, Inquiry into the National Electricity Market report - November 2021 | ACCC, December 2021, page 34.

5.3 What other regulators do

The purpose of benchmarking is to test Aurora Energy's proposed CTS figure against CTS allowances for retailers in other Australian jurisdictions. Prior to the commencement a pricing investigation, it also provides an opportunity to review the methodologies used by other regulators in the NEM.

Previously, the Regulator has benchmarked Aurora Energy's proposed CTS against the ACCC's Inquiry into the National Electricity Market Reports and investigations by the ICRC, AER and ESC. When benchmarking, it is important to acknowledge that each regulator has slightly different methodologies and approaches to allocating costs, so care must be taken in making direct comparisons.

The approaches taken by other regulators are discussed below.

ICRC

The ICRC regulates standing offer electricity prices for small customers in the ACT. It applies a pricing model that calculates the maximum average percentage increase that can be applied to regulated tariffs in each year of the regulatory period. Under this model, the costs for each category are calculated, making an allowance for retail operating costs and a retail margin. This figure is then compared to the estimate from the previous year, ultimately producing a maximum percentage increase to be applied to retail tariffs. Under the ICRC's framework, retail costs are inclusive of CTS and customer acquisition and retention costs.

The ICRC has released its final price direction for the 2024-27 regulatory period. It estimates customer weighted average retail operating costs using data from the three largest retailers operating in the ACT. However, due to the small sample size, accuracy of data concerns and commercial in confidence considerations, ICRC cross-checks the retail operating costs of ActewAGL (the regulated retailer) against those reported by the AER in its Default Market Offer (DMO), as well as the ESC's decision on the Victorian Default Offer (VDO). ActewAGL's retail operating costs are adjusted by CPI each year.

ESC

The ESC regulates prices in Victoria and releases an annual VDO. Under the ESC's cost stack framework, retail costs are comprised of retail operating costs and customer acquisition and retention costs. Retail operating costs are calculated as the weighted average of Victorian retailers' actual operating costs, using data from the previous two financial years, adjusted for inflation. Regarding customer acquisition and retention costs, the ESC uses the ACCC's 2013-14 retail and electricity pricing inquiry as a benchmark, also adjusted for inflation, with the ACCC's inquiry considered to be more robust than the retailer customer acquisition and retention data.

QCA

The QCA sets regulated prices for electricity in regional Queensland. The costs of supplying electricity in regional Queensland are much greater than in south-east Queensland (SEQ). For this reason, the Queensland Government implemented the Uniform Tariff Policy (UTP), which is a subsidy to ensure that customers in regional Queensland do not pay more for electricity than customers in SEQ. QCA sets prices based on the cost of supplying small customers (residential and small business) in SEQ which is an unregulated competitive market. This arrangement benefits regional customers, who would otherwise incur much greater prices for electricity.

QCA takes a different approach to setting notified prices when compared with other regulators. Its methodology is broadly split in two - a network component and a retail component. To ensure consistency with the UTP, standard retail tariff costs for small customers are based on the competitive Energex distribution area of SEQ. The retail component is comprised of energy costs (wholesale electricity costs, Renewable Energy Target and energy losses), metering services and retail costs (operating costs and a retail margin). Both energy and retail costs are assessed by consultants ACIL Allen.

The QCA does not separate retail operating costs (i.e., CTS) and the retail margin. The Regulator is therefore unable to make use of the QCA's methodology when setting Aurora Energy's CTS.

AER

The AER is responsible for setting a DMO each financial year. The DMO applies to the NEM regions in South-east Queensland, South Australia and New South Wales. From the AER's 2024-25 final decision, retail costs include CTS, cost to acquire and retain customers (CARC), smart meter costs and bad and doubtful debt costs. These retail costs are summed in a 'cost-stack' methodology. In order to estimate CTS, CARC and bad and doubtful debt components, the AER referred to the ACCC's *Inquiry into the National Electricity Market - December 2023* report. To estimate smart meter costs, data is obtained directly from retailers. This data includes specifics on the number of customers by meter and tariff type, one-off or up-front installation fees and whether the costs are then recovered by such fees.

ACCC

The ACCC's *Inquiry into the National Electricity Market - December 2023* report details the costs of electricity retail services in the NEM, excluding Tasmania. From 2013-2022, the ACCC reported consistent declines in retail costs (which are inclusive of CTS and CARC), attributed to increased retail competition. The Regulator considers that the ACCC inquiry provides a useful data source for benchmarking and intends continuing to use this information as a point of comparison for the upcoming pricing investigation.

5.4 Key issues

Tasmanian retail electricity data

In considering the approach for the upcoming investigation, the Regulator considered whether it would be able to compare Aurora Energy's CTS to other retailers operating in Tasmania. As discussed above, this is what regulators in other jurisdictions have done as part of their investigations.

Unlike other jurisdictions, the Tasmanian retail electricity market has a single dominant retailer, Aurora Energy. Therefore, due to the small market share of the other retailers operating in Tasmania and commercial in confidence considerations, the Regulator considers that it would be impractical to compare Aurora Energy's CTS with other retailers operating in Tasmania at this point in time. However, in the event that the market share of other retailers continues to grow, the Regulator may consider comparisons with other Tasmanian retailers in future investigations.

Efficiency factor

During the 2022 Standing Offer Price Investigation, the Regulator engaged Utility Regulation Advisory and Oakley Greenwood (together referred to as the Review Team) to help inform the Regulator's decision on Aurora Energy's CTS. The Review Team recommended that an efficiency factor be applied to Aurora Energy's CTS. The purpose of an efficiency factor is to account for potential future cost savings due to increases in productivity. The Review Team considered, based on the ACCC's *Inquiry into the National Electricity Market - November 2021* report, that the compound average growth rate for CTS and CARC is a reliable indicator of NEM retailers' productivity and that ultimately, non-big three retailers had experienced productivity gains over the period observed.

The Regulator considers that there is also merit in examining the application of an efficiency factor for the 2025 Determination. Due to an increase in in-house expertise, the Regulator considers that engaging a consultant is not necessary at this stage. This will also help to lower the cost of the investigation, which ultimately is borne by customers.

Adjustment mechanism for customer numbers

Under this mechanism, Aurora Energy's CTS on a per customer basis is increased if Aurora Energy's customer numbers decline (as there would be fewer customers to recover fixed costs from) or is reduced if customer numbers increase.

The Regulator proposes removing this adjustment mechanism on the basis that Aurora Energy intends rebalancing its tariffs during the regulatory period. As a result of this rebalancing, it is expected that Aurora Energy will be able to recover more of its fixed costs than was previously the case. Furthermore, other regulators do not include such a mechanism in their CTS calculations.

Treatment of cloud-based system costs

Prior to the 2022 Standing Offer Price Investigation, costs associated with Aurora Energy's IT systems were treated as capital expenditure and therefore were not included in its CTS. However, during the 2022 Investigation, Aurora Energy implemented a new cloud-based billing system (referred to as Software as a Service (SaaS)). Under the current accounting standard[14], the costs related to SaaS were treated as operating expenditure.

More recently, regulators in some jurisdictions are considering treating these costs as capital expenditure. For example, in its *SA Water Regulatory 2024 Draft Decision*, the Essential Services Commission of South Australia (ESCOSA) is considering requiring SA Water to capitalise rather than expense these costs. In principle, ESCOSA's position is that, where control of the cloud-based technology rests with SA Water (for example, it has control over installing and running the cloud-based software) it would be more appropriate to capitalise

[14] In April 2021, international accounting standards changed, with the International Financial Reporting Standards Interpretations Committee deciding to treat this expenditure as operating expenditure.

those costs. Treating these costs as capital expenditure spreads the costs over the expected useful life of the asset.

Cost allocation manual

In the 2022 Investigation Final Report, the Regulator stated it would examine the merits of requiring Aurora Energy to prepare separate regulatory accounts and/or implement activity-based costing prior to conducting the upcoming pricing investigation. Upon considering the arrangements in other jurisdictions and the benchmarking information that will be available for the next pricing investigation, the Regulator decided not to require Aurora Energy to prepare separate regulatory accounts and/or implement activity-based costing at this stage.

Instead, the Regulator required Aurora Energy to create a cost allocation manual to be introduced to its business operations prior to the next pricing investigation. The purpose of the manual is to establish a consistent basis for allocating costs between the regulated and unregulated segments of Aurora Energy's business.

5.5 Proposed approach

The Regulator proposes taking a similar approach in calculating Aurora Energy's CTS as that used in the 2022 Standing Offer Price Investigation. In particular, the Regulator proposes:

- continuing to use a cost build-up methodology together with benchmarking information, including the ACCC's *Inquiry into the National Electricity Market - December 2023*, to assess Aurora Energy's CTS;
- applying an efficiency factor across all CTS components; and
- adjusting CTS for inflation for each year other than the first year of the regulatory period.

However, the Regulator also proposes some changes to the current approach including:

- removing the adjustment mechanism that takes account of changes in customer numbers;
- further considering the treatment of cloud-based software costs including decisions made by other regulators with respect to these costs; and
- Aurora Energy implementing a cost allocation manual prior to the pricing investigation.

> The Regulator seeks feedback on its proposed approach to calculating Aurora Energy's CTS, in particular:
>
> - removing the adjustment mechanism that takes account of changes in customer numbers; and
> - the treatment of cloud-based software costs.

6 RENEWABLE ENERGY TARGET COSTS

6.1 Background

The NMR includes an estimate of the annual costs of Aurora Energy complying with the Australian Government's Renewable Energy Target (RET) Scheme.

The Scheme creates a guaranteed market for renewable energy, using a mechanism of tradeable certificates with each certificate representing one-megawatt hour of renewable electricity generated.

Electricity consumers pay for this government requirement through obligations imposed on purchasers of wholesale electricity (including retailers) who then pass through the cost of complying with the obligations to customers.

The RET is made up of two schemes:

- the Large-scale Renewable Energy Target (LRET); and
- the Small-scale Renewable Energy Scheme (SRES).

The LRET supports the development of large projects such as wind farms and commercial solar farms. Electricity retailers must purchase and surrender a specific number of Large-scale Generation Certificates (LGCs) each year. The number of LGCs to be surrendered each calendar year is calculated using the Renewable Power Percentage (RPP) which is determined by the Clean Energy Regulator (CER).

The SRES supports investment in smaller technologies such as rooftop solar panels and solar hot water heaters through the generation of Small-scale Technology Certificates (STCs). STCs created must be purchased by electricity retailers. The number of STCs that retailers must purchase and surrender over the course of each calendar year is calculated using the Small-scale Technology Percentage (STP) which is also determined by the CER.

The RPP and STP are applied to the volume of wholesale electricity purchased by a retailer in a calendar year adjusted for the applicable DLF. In March of each year, the CER publishes the final binding percentages for that calendar year for the RPP and the STP and provides non-binding STPs for the following two calendar years.

In summary, an electricity retailer's annual costs of complying with the RET are determined by the RPP, the STP, the price of LGCs and STCs and the volume of electricity purchased (or liable MWh).

6.2 Current approach

6.2.1 Large-scale Renewable Energy Target costs

The formula for estimating the total LRET costs for the current regulatory period is as follows:

Total LRET cost =
Cattle Hill MWh × \$/LGC Cattle Hill + (RPP × liable MWh - Cattle Hill MWh × \$/LGC Market

Where:

Cattle Hill MWh	=	The volume of LGCs purchased under the Cattle Hill Wind Farm Power Purchase Agreement (PPA) for the relevant year[15].
\$/LGC Cattle Hill	=	The LGC price under the Cattle Hill PPA for the relevant year.
RPP	=	RPP published by CER.
liable MWh	=	Amount of liable MWh for the relevant year.
\$/LGC Market	=	The forward LGC price for the remaining volume of LGCs that Aurora Energy is required to purchase for the relevant year under the RET scheme.

The CER publishes its RPP by 31 March on a calendar year basis. However, the allowance for RET costs is calculated on a financial year basis. Under the 2022 Determination, the Regulator used the CER's RPP for the first half of each financial year of the regulatory period. For the second half of each financial year of the regulatory period, the Regulator used the formula outlined in section 39(2)(b) of the *Renewable Energy (Electricity) Act 2000 (Cwlth)* to calculate the forecast RPP.

This formula is as follows:

$$\text{Renewable power percentage for the previous year} \times \frac{\text{Required GWh of renewable source electricity for the year}}{\text{Required GWh of renewable source electricity for the previous year}}$$

The required GWh of renewable source electricity for each calendar year from 2001 to 2030 inclusive is specified in section 40 of the Renewable Energy (Electricity) Act.

15 The details of the Cattle Hill PPA are commercial-in-confidence.

The Regulator recognises that retailers that are wholly exposed to RET prices under spot prices or short-term contracts may face unacceptable financial risks and pay more for LGCs than under a longer-term contract. The Regulator also notes that Power Purchase Agreements[16] (PPAs) enable retailers to manage these risks and understands that many retailers enter into PPAs for this reason. In the 2022 Determination, the Regulator therefore decided to include Aurora Energy's long-term contractual commitments under the Cattle Hill PPA in Aurora Energy's LGC cost allowance.

The weighted LGC price for the relevant year was calculated as follows:

1. Forecast the percentage of Aurora Energy's total LGC liability that applied to the estimated load required to supply customers on standard retail contracts.

2. Apply the percentage calculated in 1. to the total number of LGCs purchased under the Cattle Hill PPA for that year to determine the number of LGCs to be included in the weighted LGC price.

3. Apply the average forward price for that year to the remaining LGCs required for the estimated load.

The forward price for the remaining LGCs in the relevant year was estimated as the average weekly forward LGC price over 12 months of the previous year. This required Aurora Energy to source the weekly forward prices from an independent market-based source, such as an energy broker.

6.2.2 Small-scale Renewable Energy Scheme costs

The formula for estimating the SRES costs was as follows:

Total SRES cost = (STP x $/STC x liable MWh)

As with the RPP, the CER publishes its binding STP by 31 March on a calendar year basis. Under the 2022 Determination, the Regulator used the CER's binding STP for the first half of each financial year of the regulatory period. For the second half of each financial year of the regulatory period, the Regulator used the CER's non-binding STP.

The Regulator required Aurora Energy to use the latest available forecast STC price. However, in allowing for over and under recoveries, the Regulator effectively allows Aurora Energy to recover its actual RET costs.

6.2.3 Volume of liable MWh

As the LRET and SRET schemes operate on a calendar year basis, it is necessary to allocate the estimated annual liable MWh between the first half of the financial year (i.e., 1 July to 31 December) and the second half of the financial year (i.e., 1 January to 30 June).

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[16] A PPA is a contract that allows an electricity retailer to purchase LGCs at predetermined prices over a long time period (typically around 10 years) as a way of managing the risks relating to supply issues and price volatility in the LGC market.

Based on advice provided by Aurora Energy as to the seasonality of demand, under the 2022 Determination the Regulator allocated Aurora Energy's annual liable MWh in the proportions of 55:45 between the first half and second half of each financial year respectively, for each year of the regulatory period.

6.3 What other regulators do

The ICRC, QCA and ESC estimate their respective retailers' costs of complying with the Australian Government's mandatory renewable energy schemes using a market-based approach.

ICRC

The ICRC applies a market-based approach for determining efficient LRET and SRES costs. The ICRC's model determines LGC and STC prices based on publicly available spot price data averaged over a 12-month period to the end of April. The ICRC then applies the CER's RPP and STP percentages to the forecast prices and holding costs to the forecast customer load. The ICRC uses the CER's RPP for the first half of the calendar year and then estimates the RPP for the second half.

The Commission's pricing model operates on a financial year basis. LRET and SRES costs for a financial year are therefore derived by apportioning calendar year costs based on the half-yearly load weights provided by the regulated retailer, ActewAGL.

In addition to the timing of the LRET and SRES costs, the ICRC also includes a green scheme certificate holding cost in its pricing model, which is calculated by estimating the cost of debt. This is because retailers typically buy certificates in advance to manage price volatility and to avoid being unable to purchase enough certificates to meet their obligations.

QCA

QCA uses a consultant, currently ACIL Allen, to estimate LRET costs using a market-based approach. Under this approach, LGC prices are based on forward prices for certificates provided by broker TraditionAsia. ACIL Allen uses the CER's RPP for the first half of the price period and estimates the RPP for the second half of the price period.

ACIL Allen estimates SRES costs using the STP for the first half of the price period and the latest available non-binding STP for the second half of the price period. STC prices were based on the clearing house price of $40 per certificate as historically the spot prices have been at or close to this price.

The QCA only allows for an adjustment to the small-scale renewable energy scheme due to the binding small scale technology percentage for the second half of the financial year not being published at the time the prices are set. The QCA uses forward large-scale generation certificate energy prices in setting prices and makes no further adjustment on these.

ESC

The ESC has a separate environmental cost component that includes the cost of complying with the LRET and the SRES.

The ESC uses a market-based approach to estimate LRET costs. The applicable market price for LGCs is determined by taking 12-month volume-weighted average of LGC forward trades for each year as reported by Demand Manager, an energy broker. The ESC uses the CER's RPP for the first half of the calendar year and then estimates the RPP for the second half.

To estimate the SRES, the ESC uses the binding STP and the most recent non-binding STP. The ESC uses the clearing house price of $40 per certificate.

6.4 Proposed approach

In the 2022 Determination, the Regulator decided to include the Cattle Hill PPA in the LGC cost allowance for Aurora Energy. This is because prudent retailers use long term PPAs to manage risks and PPAs can provide more price certainty for regulated customers.

Therefore, the Regulator proposes continuing to use the current approach used for the 2022 Determination to forecast RET costs.

7 METERING COSTS

7.1 Background

Metering costs comprise the costs associated with the installation, maintenance and reading of meters, together with the costs associated with the introduction of metering competition and fee-based metering services.

Under the National Electricity Rules (NER), retailers are responsible for engaging a Metering Coordinator for their small customers. The Metering Coordinator appoints a Metering Provider and a Metering Data Provider, and is responsible for managing service levels, rule compliance and performance reporting. Metering Coordinators and the services they provide are not price regulated. The NER also requires that any new or replacement meter must be an advanced meter.

There are numerous meter types used which can be broadly split into two groups:

- Basic accumulation meters, referred to as Type 6 meters. These are analogue meters that measure the total electricity consumed over a period and require manual reading. The Local Network Service Provider, TasNetworks, continues to be responsible for reading these meters; and
- Advanced meters, also referred to as interval, smart meters, or Type 4 meters. Advanced meters record usage in real time and are read in 15 or 30-minute intervals. Advanced meters are able to record usage against multiple tariffs and can be read remotely by the Metering Provider driving through the area and picking up the signal from the meter.

Aurora Energy appointed Yurika (formerly Metering Dynamics) to manage the installation, maintenance and reading of advanced meters from 1 December 2017. Yurika continues to be responsible for all services relating to the advanced meters installed between 1 December 2017 and 31 May 2021.

TasMetering was appointed as an additional Metering Coordinator from 1 June 2021 following a tender process. Since that time, all new advanced meters are installed, read and maintained by TasMetering.

Aurora Energy has advised the Regulator that an estimated 206 182 advanced meters had been installed in Tasmania as of March 2024 (constituting 77 per cent of Aurora Energy customers). Aurora Energy expects to install a further 38 554 advanced meters during 2024-25. It is therefore estimated that by the beginning of the next regulatory period on 1 July 2025, there will be 10 340 accumulation meters yet to be replaced by advanced meters.

Following the Tasmanian Liberal Party's commitment in 2021[17] to replace all accumulation meters in Tasmania with advanced meters by 2026, the remaining 10 340 installations are

[17] The Tasmanian Liberal Party made a commitment before the May 2021 election to accelerate the rollout of advanced meters in Tasmania by 2026.

expected to occur by December 2026. From discussions with Aurora Energy, these remaining installations are expected to be more difficult, due to issues such as the remoteness of location and the prevalence of asbestos in some meter boxes.

The Australian Energy Market Commission's (AEMC) 2023 review of the national regulatory framework for advanced meters recommended a target of universal uptake of advanced meters by 2030 in all NEM jurisdictions.

7.2 Current approach

Under the 2022 Determination, the Regulator approved Aurora Energy forecasting its metering costs by multiplying a weighted average calculation of metering costs per tariff by the appropriate number of billings days. The Regulator also introduced the requirement that Aurora Energy reconciles the number of billing days with the forecast of the customer numbers used in the NTB.

The current approach ensures that the total costs for metering are shared across all small customers, irrespective of the type of meter they have, despite the cost of advanced meters being substantially higher than for accumulation meters. This reflects the expectation that eventually all accumulation meters will be replaced with advanced meters.

During the Regulator's methodology review in 2022, the Regulator considered changing this approach, so that the prices charged to a customer reflected whether they had an advanced meter or an accumulation meter. This was in effect proposing that customers with an advanced meter be charged a higher price than those with accumulation meters, rather than the cost of advanced meter installation being smoothed across the customer base. However, at the time, submissions to the methodology review stated that doing so would be contrary to Government policies aimed at increasing the rollout of advanced meters, and that some customers do not have a choice as to whether an advanced meter is installed, such that it would be unfair to charge these customers more. The Regulator ultimately decided not to change the way that metering costs are accounted for in electricity prices, maintaining the approach of smoothing the costs across the customer base.

Under the 2022 Determination the Regulator permitted Aurora Energy to recover the following metering costs:

a) the aggregate of metering charges based on tariff, meter type and billing days for both accumulation and advanced meters;

b) the ongoing annual capital cost associated with accumulation meters that have been replaced by advanced meters; i.e. in accordance with the AER's electricity transmission and distribution determination for the period 1 July 2019 to 30 June 2024, [18]

[18] https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/tasnetworks-determination-2019-24

TasNetworks is permitted to recover the remaining capital costs of these meters where they have a remaining useful life (i.e. depreciation);

c) depreciation related to capital expenditure required to meet the set-up costs associated with the start of metering competition (costs to be written off over six years commencing from 1 December 2017); and

d) fee based metering services recovered on an annual basis.

On 30 April 2024, the AER released its final TasNetworks Electricity Distribution Determination for the regulatory period from 1 July 2024 to 30 June 2029. This determination set TasNetworks' revenue for the period and in particular, the amount that TasNetworks can recover in relation to ongoing capital costs of accumulation meters replaced by advanced meters. In its determination, the AER recommended that all accumulation meters be fully depreciated by 30 June 2029. In light of the AER's determination, the Regulator will consider the extent to which Aurora Energy can recover the capital costs that are passed through by TasNetworks.

7.3 What other regulators do

The treatment of metering costs differs between jurisdictions as set out in the following sections.

AER

In May 2024, the AER released its final determination for retail electricity default market offers in New South Wales, South Australia and South East Queensland. The AER includes advanced meter costs as a component of retail costs for its DMO determination.

Retailers in NSW, South Australia and South East Queensland are responsible for managing advanced meter installation and maintenance costs. The AER seeks advanced meter cost data directly from retailers.

The final determination incorporated stakeholder views on issues relating to advanced metering costs, such as what relevant cash flow impacts on retailers could be expected to result from anticipated installation rate increases, whether to use historical or forecast installation rates, and whether up-front fees for installation should be included in allowable recoveries, following the AEMC's recommendation that up-front fees for metering installations be prohibited.

The AER resolved to include the recovery of up-front installation fees in its advanced meter allowance calculation. While it was acknowledged that retailers that continue to charge up-front fees may recover more revenue under this determination than would reflect their efficient costs, the risk was considered minimal as few retailers charge these fees.

The AER also decided to continue its current approach of using historical installation data, rather than forecasting installation rates, despite stakeholders broadly supporting the forecast approach. The AER reasoned that its forecasts would be less accurate than historical data, at least until retailers released their plans to retire all basic meters and replace them with advanced meters by 2030, as recommended by the AEMC.

ICRC

On 23 May 2024, the ICRC released its final report and price direction following the completion of its 2024-27 retail electricity price investigation for the ACT.

The 2024-27 price direction continues the same treatment of metering costs as the 2020 price direction. The approach spreads the cost of advanced meters across the total base of small electricity customers rather than charging individual customers for installation and meter reading (the same approach as currently adopted by the Regulator). This approach was based on fairness and equity considerations.

To estimate advanced meter costs, the ACT's electricity retailer and advanced meter installer, ActewAGL, provides an annual forecast of the weighted average cost per advanced meter and a forecast of the number of advanced meters. The ICRC expects that advanced meter costs will increase as the accelerated rollout continues.

Prior to its 2020 price direction, the ICRC did not include the costs of advanced meters in its electricity pricing model.

QCA

As outlined in its final determination released on 7 June 2024, the QCA includes small customer metering service costs in the retail cost component of customer tariffs. Metering costs are based on metering and advanced metering services and the installation rate for advanced meters in regional Queensland.

In regional Queensland, a customer may choose to disable the remote communication function on their type 4A advanced meter. In this case the retailer is then required to manually read the meter. The QCA has determined to set charges in a way that reflects the average costs to retailers of having to manually read meters.

ESC

The ESC does not include a separate cost component for metering when determining its annual VDO. This is because electricity distribution businesses in Victoria are required to install advanced meters for all small customers. As a result of past policies, advanced meters have been compulsory in all Victorian homes and businesses since 2006. To recover the cost of metering (which includes meter reading and other on-going costs), the AER approves Victorian distribution network businesses charging retailers for advanced meters on a per customer basis. Metering costs are therefore factored into the network cost component for retailers.

7.4 Issues

7.4.1 Slowing down the rollout rate of advanced meters

Metering costs continue to increase as a proportion of Aurora Energy's NMR, constituting 6.3 per cent of Aurora Energy's proposed NMR in 2024-25, compared to three per cent of the 2019-20 NMR. This is driven by the higher per unit cost of advanced meters. Direct metering charges have increased from $3.5 million in 2019-20 to $30.5 million in 2024-25. The direct metering charge for basic meters has decreased over this period from $11.6 million in 2019-20 to $8.2 million in 2024-25, as basic meters are replaced with advanced meters.

The Government previously committed to roll out advanced meters to every home and business by 2026, ahead of the AEMC's target of 2030. By the start of the next regulatory period of 1 July 2025, it is expected that around 96 per cent of advanced meters will have been installed, with only 10 340 meters remaining to be installed. Aurora Energy intends to install these remaining meters over the 18 months to December 2026, in line with the Government's commitment.

However, Aurora Energy has noted that as the uptake increases, completing the remaining advanced meter installations may be more challenging and come at a higher cost.

Furthermore, the Regulator is not bound by the commitment to roll out all advanced meters by 2026, but instead must consider the objectives of promoting efficiency in electricity supply and protecting the interests of electricity consumers in line with the ESI Act. As such, and notwithstanding the Government's commitments, there may be scope for the rollout of the remaining advanced meters to align with the AEMC's relatively longer timeframe.

Modelling undertaken by the Regulator indicates that if the remaining advanced meters were installed in line with the 2030 target, it would reduce overall metering charges over the 18 months from July 2025 to December 2026 by $0.51 million, compared to the scenario where the remaining meters were installed at an equal monthly rate over the 18 months to December 2026.

This would effectively spread out the metering charges associated with the remaining advanced meter installations over a longer time period, reducing the annual charges. Holding everything else constant, this would put some downward pressure on standing offer electricity prices over the 18 months from July 2025 to December 2026.

7.4.2 Method for calculating how many customers are on market contracts

Currently, when calculating TasNetworks' weighted average cost of servicing existing basic meters, a factor is applied to the total number of customers on Tariff 22 (General Business customers) to account for the proportion of these customers on market contracts rather than standard retail (standing offer) contracts.

However, customers on Tariffs 75 and 94 may also be on market contracts rather than standing offers. Additionally, with Aurora Energy proposing to introduce flat rate market retail contracts in place of grandfathered standing offer flat rate tariffs (31 and 41, 43 and 22), some residential customers on Tariffs 31 and 41 may choose to move to market contracts.

Aurora Energy has noted that only a small proportion of business customers are currently able to move between market offers and regulated offers, and so any improvement in the methodology for calculating the split would not materially affect the NMR. However, calculating the proportion of market customers may become more important over the regulatory period if more customers are able to move to market offers.

The Regulator is therefore considering applying a similar factor to these other tariffs to give a more accurate estimate of the number of standing offer customers. This would more fairly apportion costs between market contract customers and regulated customers, ensuring that charges to regulated customers are no greater than they need to be.

The Regulator acknowledges the difficulties in forecasting how many customers on each tariff will be on market contracts. The factors applied to each tariff will need to be based on a robust method. The Regulator intends exploring different methods to ensure that costs are appropriately apportioned between regulated customers and market customers.

7.4.3 Depreciation allowance for capital expenditure associated with the start of metering competition

Under the 2022 Determination, metering costs were allowed to be recovered for capital expenditure required to meet the set-up costs associated with the start of metering competition (under the change to the National Electricity Rules in 2017 to allow metering providers to compete for business). The period for this recovery was six years commencing 1 December 2017. As this arrangement has ended, Aurora Energy will not be able to recover any of these metering costs during the next regulatory period.

7.5 Proposed approach

The Regulator proposes using the same approach to calculate metering costs as in the 2022 Determination, but is considering changes to the allowance for the recovery of metering costs and refining the method to calculate the proportion of regulated customers on various tariffs.

The Regulator seeks feedback on a lower allowance for the recovery of metering costs and on refining the method for calculating the proportion of regulated customers and market customers on Tariffs 22, 31, 41, 75 and 94.

8 RETAIL MARGIN

8.1 Background

The retail margin is intended to compensate Aurora Energy for the risks it faces providing retail services to customers on standard retail contracts. The retail margin is included in Aurora Energy's NMR and is therefore ultimately reflected in standing offer prices approved by the Regulator.

There are generally two approaches to estimating the retail margin:

- undertaking a bottom-up and / or expected returns analysis of the retailer's financial position to determine an appropriate retail margin; and / or
- determining the appropriateness of the retailer's margin by benchmarking against margins approved by regulators in other jurisdictions.

Under Section 40AB(1)(b) of the ESI Act, the Regulator is to:

> …take into account the principle that the maximum prices that may be imposed by the retailer under standard retail contracts in respect of small customers are to be such as will enable the retailer, after the operational costs are taken into account, to make a reasonable return on its investment in respect of the provision of standard retail services, taking into account the risk of making that investment.

Aurora Energy's average retail margin, per customer, may differ from the Regulator's allowance due to Aurora Energy's actual costs being higher or lower than allowed in the Regulator's price determination.

8.2 Current approach

In the 2022 Determination, the Regulator used a benchmarking approach in setting the retail margin, taking account of the risks Aurora Energy faced in delivering retail services under standard retail contracts. This also took into account the risks that Aurora Energy may face in Tasmania compared with retailers operating in interstate markets, including energy price risk and volume-related wholesale electricity price risk.

Prior to the 2022 Determination, the retail margin was applied to the sum of the cost components which meant that an increase in costs led to a larger retail margin in dollar terms and vice versa. To mitigate against this outcome, the Regulator decided to calculate the retail margin on a dollar amount per customer basis for the current regulatory period.

8.3 What other regulators do

The following is a summary of arrangements in other jurisdictions.

ICRC

The ICRC has previously used a benchmarking approach when determining a retail margin and expressed this as a percentage of costs. However, in its final determination for 2024-27, it has used a different approach.

The ICRC engaged Frontier Economics to examine a benchmarking approach and an expected returns approach to assess an appropriate retail margin. The key objective of the expected returns approach is to estimate the minimum retail margin required to compensate equity investors in a notional electricity retailer for the systematic or non-diversifiable risk (such as economic, political, or social risks) that they bear when committing equity capital to the firm.

Frontier Economics also explored the impact of using either a percentage margin or a fixed dollar margin. It considered that a retail margin as a percentage ignores that increasing energy costs reduce the risk faced by the retailer and so overcompensates the retailer, whereas a constant margin as a dollar amount ignores that some fixed costs have increased so that the retailer is undercompensated as energy costs increase. Frontier Economics concluded that a hybrid approach, giving equal weight to both the percentage margin and the dollar margin, appears to provide appropriate compensation.

The ICRC decided to implement the margin using a 50:50 weighting for the percentage and dollar amount. The ICRC considered that this approach provides a more reasonable balance between providing a return to retailers and more stable prices for consumers than the current approach of only using a percentage margin.

ESC

In its final decision for 2024-25, the ESC determined to keep using a regulatory benchmarking approach to setting the retail margin and to keep the same margin (5.3 per cent of costs) that was applied in 2023-24. To ensure that the margin was still appropriate, the ESC considered the following factors:

- margins set by other Australian regulators;
- a comparison of Victorian market offer prices relative to VDO prices between 2019 and 2023;
- analysis prepared by Frontier Economics on the expected returns approach; and
- Victorian retailers' actual margins and actual margins of retailers operating in the NEM as presented in the ACCC's Inquiry into the NEM.

QCA

The QCA's model does not have a specific allowance for a retail margin. Rather, the QCA's approach focuses on estimating an efficient total level of retail costs, which implicitly includes some retail margin.

AER

In its final determination for the 2024-25 DMO, the AER estimated an 'efficient margin' by using a number of different approaches, including:

- inferring margins from advertised offers available between 1 July 2023 and 31 August 2023;
- inferring margins within the ACCC's findings of the actual retail prices charged to customers on 1 August 2023;
- assessing historical trends in individual retailers' actual margins and incurred costs reported to the ACCC as part of its retail electricity market inquiry; and
- benchmarking retail margin determinations in other jurisdictions.

The AER engaged ACIL Allen to assist with this work including assessing the relative merits of the methodologies and conducting the analysis based on advertised offers.

The AER also received a range of views on whether the margin should be calculated as a percentage of the DMO price or as a fixed dollar amount. Most retailers considered that the retail margin should be a percentage, to ensure that it moves relative to retailer risk. In contrast, the NSW Energy Minister held concerns that a percentage approach would exacerbate price increases; the South Australian Department for Energy and Mining commented that the AER should focus the DMO on the objective of protecting customers; and retailer Energy Locals supported a fixed dollar retail margin as it would give retailers greater certainty.19 Having considered the feedback, the AER has decided to continue to calculate the margin as a percentage of the DMO price.

ACCC Inquiry into the National Electricity Market

The ACCC's 2019 Inquiry into the NEM presented margins achieved by electricity retailers in each jurisdiction for 2018-19. The ACCC used data obtained directly from retailers through its information gathering powers. This information is not otherwise publicly available and only reported on at an aggregate level.

Since 2019, the ACCC has released updated reports. The latest update was published in December 2023 and includes more recent information on margins.

[19] AER, 'Default market offer prices 2024-25 - Draft determination', p 56.

8.4 Issues

Energy price risks

It is not straightforward to compare the risks Aurora Energy faces with those faced by other electricity retailers operating in the NEM, given the particular features of the electricity market in Tasmania, including the regulatory arrangements for wholesale electricity. The Regulator also acknowledges that it is difficult to quantify the differences in these risks.

Nonetheless, under section 40AB(1)(b) of the ESI Act, the Regulator is required to take into account the risks that Aurora Energy faces.

The retail margin as a percentage of costs or as a fixed dollar amount

Until recently, the Regulator and regulators in other jurisdictions have calculated a retail margin as a percentage of costs / prices. However, as discussed, the Regulator calculated the margin as a fixed dollar amount in its 2022 Determination and the ICRC has decided to partly use a fixed dollar amount in its 2024 Determination.

In addition to the views expressed to the AER on this matter, the former chair of the ESC, Mr Ben-David, has stated that he supports a fixed dollar amount because whether the wholesale market moves or not, a retailer's margin is fixed in dollar terms.[20]

8.5 Proposed approach

Having considered the arrangements in other jurisdictions, the Regulator's proposes continuing to apply a benchmarking approach to setting a retail margin that takes into account:

- the retail margins set by other regulators;
- the ACCC's Inquiry into the NEM; and
- Aurora Energy's risks compared to the risks facing retailers operating in other Australian states and territories.

The Regulator is seeking comments from stakeholders on whether the margin should continue to be calculated on a dollar amount per customer basis or if a hybrid approach is preferred.

[20] Millions of Australian households paying too much for electricity, according to ACCC - ABC News, 12 July 2023.

9 OTHER COSTS

There are some other smaller cost components that are included in the NMR cost stack.

9.1 AEMO costs

AEMO's operating costs are funded through annual fees levied on market participants. Retailers are liable to pay a portion of these fees. The following fees are charged by AEMO to retailers:

- NEM fees:
  - Allocated fees - Market Customers;
  - Unallocated fees - General fees;
- Full Retail Competition (FRC) electricity:
  - FRC operations; and
  - Energy Consumers Australia (ECA).

NEM fees are based on customer load adjusted by the DLF while FRC fees are on a per connection point per week basis.

AEMO costs relating to payments for ancillary services are based on customer load adjusted by the DLF.

AEMO's NEM and FRC fees for the following financial year are determined by AEMO annually in May, in accordance with the NER.

9.1.1 AEMO fees

9.1.1.1 Current approach

Under the 2022 Determination, the Regulator estimated Aurora Energy's AEMO fees for participating in the NEM and for FRC electricity each year of the regulatory period using the customer numbers from the NTB, the DLF and the fees as determined by AEMO, and allowed Aurora Energy to recover these costs from customers through standing offer prices.

9.1.1.2 What other regulators do

The approach taken by the ICRC, QCA and ESC in relation to AEMO fees is similar to that adopted by the Regulator.

9.1.1.3 Proposed approach

The Regulator proposes continuing its current approach to estimating NEM fees and FRC electricity fees.

9.1.2 Ancillary Services

9.1.2.1 *Current approach*

Under the 2022 Determination, the Regulator estimated Aurora Energy's ancillary service fees by multiplying the average monthly rate of ancillary fees ($/MWh) based on a 12-month period prior to April in the year immediately before the price period by the forecast small customer load in the NTB adjusted by the DLF. These fees include Frequency Control Ancillary Services fees. As for AEMO fees, the Regulator allowed Aurora Energy to recover these costs from customers through standing offer prices.

9.1.2.2 *What other regulators do*

The ICRC, ESC and QCA all use a similar approach.

9.1.2.3 *Proposed approach*

The Regulator proposes continuing with its current approach to estimating ancillary services fees for the next regulatory period.

9.2 Adjustments

The standing offer prices to apply to the next price period are currently calculated using a NMR calculated in May / June of each year. Some NMR components such as the WEC are already known for the next period at the time prices are calculated.

However, for other components, such as RET costs, the cost per unit of electricity for the next price period must be based on an estimate as the costs that will apply during that price period are not available at the time prices are set.

For NMR components based on estimated values, Aurora Energy may either under recover or over recover its costs based on the prices charged during a price period, depending on how actual costs vary from forecast costs.

The NMR may also include adjustments relating to the impact of tax events or material changes in Aurora Energy's costs as specified under Regulations 12 and 16 of the Pricing Regulations.

For 2024-25, there is an under recovery of costs from the previous year of approximately $536 000 or 0.09 per cent of the NMR.[21]

9.2.1 Current approach

To address that some costs are not known at the time prices are approved, the Regulator's 2022 Determination allowed the difference between forecast cost components and the actual

[21] Aurora Energy, *Pricing Proposal for Period 3 of the 2022 Standing Offer Price Determination, 1 July 2024 to 30 June 2025*, page 7.

costs to be included in the NMR formula in the K_y and CF_y cost components when calculating maximum standing offer prices for subsequent price periods.

The difference between forecast and actual pass through per unit costs are included in K_y if the costs related to a period covered under a current price determination, or CF_y if the costs related to a previous price determination.

Under and / or over recoveries included in K_y or CF_y cost components are limited to cost components determined by third parties. That is, network costs, metering costs, RET costs and AEMO costs. However, in practice the applicable network tariffs and most metering costs are generally available at the time prices are approved by the Regulator for the upcoming financial year.

The Regulator calculates the under and over recoveries using the NTB in the relevant period. To estimate the NTB for each upcoming financial year under the 2022 Determination, the Regulator assessed Aurora Energy's forecast NTB using the mid-point of actual customer number data Aurora Energy has reported to the AER for the quarter ending 31 March of the current year and a forecast of customer numbers as at 31 March of the upcoming financial year.

In its pricing proposal for each year under the 2022 Determination, Aurora Energy was required to submit details of its forecast load that relates to the customer numbers. The load in Aurora Energy's forecast NTB was to be a forecast of the total amount of electricity consumed by the forecast number of customers over the 12-month period from 1 April to the following 31 March.

In calculating the over and under recovery of RET costs, the Regulator allowed for changes in the RPP and / or STP during the relevant period.

The prices used to calculate RET costs in each year will also be used when calculating any preliminary and final adjustments in relation to RET costs with respect to each year. For example, the LGC and STC prices used when calculating prices in 2022-23 must be used when calculating preliminary and final adjustments in 2023-24 and 2024-25 respectively.

In the case of over and under recovery of RET costs relating to years under the previous determination (CF_y), the LGC and STC prices used in calculating the approved prices in the relevant year will be used.

Adjustments under Regulations 12 and 16 of the Pricing Regulations are provided for in the NMR formula in the A_y cost component.

The method to calculate A_y is specified in the 2022 Guideline as:

(a) if the adjustment is due to an error, or omission[22], the value of the adjustment is to be calculated with reference to the impact of the error on the NMR ie the NMR will be recalculated incorporating the correct value but with all other values held constant. The difference between the original NMR and the recalculated NMR will be the value of the adjustment A_y; and

[22] Where the adjustment relates to a material change in costs.

(b) in all other cases, the adjustment is to be calculated using a method approved by the Regulator.

9.2.2 What other regulators do

The adjustment mechanisms used by other regulators are as follows.

ICRC

The ICRC carries out an annual recalibration of the cost component parameters. The approach to calculating some of the individual cost components for each year of the regulatory period are discussed below.

- The ICRC determines the energy purchase cost component based on data available to 30 April and energy losses based on the latest AEMO data as at 30 May. The ICRC updates forward prices, spot prices, and load.
- Network costs are updated for the regulated customer load as soon as they are approved by the AER.
- ActewAGL submits to the ICRC on or before 8 May its load weights for LRET and SRES costs (LRET and SRES costs for a financial year are derived by apportioning calendar year costs based on the half-yearly load weights provided by ActewAGL). In addition, the ICRC updates spot prices and provides for a cost adjustment to account for the difference between the estimated RPP at the time of the price determination and the actual percentage that is subsequently published by the CER.

Based on the information gathered, the ICRC determines the percentage by which the weighted average price change may be adjusted for the following year.

In undertaking the annual price recalibration process, the ICRC also allows for a regulatory change or tax change event review.

ESC

The ESC includes a mechanism that provides for variations to a price determination in the event of a material unforeseen change or error at the time of making the price determination, such as an exogenous shock,[23] that was sufficiently material to impact the benchmark established for the efficient costs to supply an electricity retail service.

QCA

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

[23] An exogenous shock refers to an event that occurs outside the control of a retailer or the industry.

and its final determination of the SRES liabilities. To account for the over or under recovery of SRES costs, the QCA applies a cost pass-through mechanism for the next regulatory period.

9.2.3 Proposed approach

The Regulator proposes continuing with its current approach for estimating and accounting for adjustments.

However, one issue to be addressed is the treatment of unaccounted for energy (UFE).

9.3 Unaccounted for energy

UFE is the difference between metered energy entering a local area and the metered energy consumed within that local area. UFE is due to a number of factors including energy theft, inaccurate or faulty meters, estimation errors associated with unmetered devices, profiling of reads to the trading interval (five minute) level or errors in the DLF.

At the commencement of the NEM in 1998, the market settlement framework applied a settlement by difference approach. Under this approach, electricity within a distribution area was billed to the local retailer except for the loss-adjusted metered electricity that was consumed by the customers of independent retailers within their local area. This meant that the local retailer (in this case, Aurora Energy) for an area bore the full risk of all residual electricity losses in that area.

Since the introduction of global settlements in April 2022, all retailers commenced being billed by AEMO for UFE within their respective distribution areas. AEMO allocates UFE to retailers based on their accounted for energy.

Aurora Energy has requested that the Regulator consider the inclusion of UFE as a cost in determining its standing offer prices.

9.3.1 Issues

With the introduction of global settlements in 2022, AEMO's weekly invoices to retailers, including Aurora Energy, separately identify UFE. Prior to this time, UFE was incorporated into the costs charged by AEMO to the local retailer, without being separately identified. As such, UFE is not a new cost to Aurora, rather it is a cost that is now measurable.

As discussed, under the previous settlement framework, Aurora Energy bore the full cost of UFE and received no additional allowance for these costs. Under the global settlement framework, all retailers operating in the Tasmanian electricity market bear these costs which means that Aurora Energy's share of UFE has been reduced and will likely continue to reduce over time.

With the accelerated roll-out of advanced meters, responsibility for validating metering data and identifying errors is increasingly shifting from TasNetworks to Metering Coordinators, which are appointed by electricity retailers. With this change in responsibility, Aurora Energy (and other retailers operating in the Tasmanian market) are currently incentivised to manage these risks and reduce UFE over time.

Further, Aurora Energy receives a retail margin allowance to compensate it for the risks it faces in providing standard retail services to its customers, of which UFE could be considered a component.

UFE costs are not known at the start of the financial year. Therefore, if the Regulator decided to provide Aurora Energy with an allowance for these costs, the costs could be treated as an adjustment in the following year. That is, if unaccounted for consumption is greater than the unaccounted for generation, Aurora Energy could be provided an adjustment for UFE in the following year for this amount which would mean that customers would pay a higher price in the following year. Conversely, if unaccounted for generation is greater than the unaccounted for consumption, Aurora Energy could be provided with an adjustment for UFE in the following year which would mean that customers would pay a lower price in the following year.

9.3.2 Proposed approach

The Regulator is seeking further information and views from stakeholders on the treatment of unaccounted for energy.

10 AURORA ENERGY'S TARIFF STRATEGY

10.1 Background

As part of previous price investigations, the Regulator has required Aurora Energy to submit a Standing Offer Tariff Strategy. The purpose of the Tariff Strategy is to set out the changes Aurora Energy intends making to its existing tariff structure during the next regulatory period.

Under the ESI Act, the Regulator has statutory objectives to promote competition and protect the interests of consumers of electricity. The Regulator does not prescribe which tariffs Aurora Energy may or may not offer to its customers. However, the Regulator would not approve a Tariff Strategy if it considered the tariffs being offered to customers or the changes proposed to be made to the tariffs were not in those customers' best interests.

10.2 Issues

Tariff rebalancing

During the second and third regulatory periods of the 2022 Determination, Aurora Energy commenced the process of addressing some cross-subsidies in its tariff base to more accurately reflect underlying costs, particularly network costs. Referred to as tariff rebalancing or a non-uniform price change, this approach has involved Aurora Energy recovering a larger amount of fixed costs from some tariffs. For example, for 2024-25, Aurora Energy increased fixed rates on tariffs by 6.8 per cent and decreased variable rates on tariffs by 1 per cent with the exception of Tariff 22 where Aurora Energy increased fixed rates by 4 per cent and decreased variable rates by 1.0 per cent. These movements across all tariffs resulted in an average 0.5 per cent price increase for 2024-25, with the price increase for individual tariffs being higher and lower than this.

Aurora Energy applied a one per cent side constraint in each of its pricing proposals for 2023-24 and 2024-25. Under this arrangement, price changes for individual tariffs would only be approved if they did not deviate by more than one percentage point from the average price change proposed to the Regulator. For example, in 2024-25, with an average price increase of 0.5 per cent across all Aurora Energy's tariffs, the maximum increase approved for an individual tariff was 1.5 per cent and the minimum price increase approved for an individual tariff was -0.5 per cent.

It is expected that Aurora Energy's Tariff Strategy for the next regulatory period will contain further rebalancing of its tariffs, with the possibility of higher side constraints. Aurora Energy has stated that it will consult on its proposed Tariff Strategy during August 2024 prior to submitting it to the Regulator for review and approval.

Grandfathering of standing offer flat rate tariffs

As a result of TasNetworks no longer offering flat rate network tariffs for new connections from 1 July 2024, Aurora Energy's corresponding regulated flat rate tariffs have been 'grandfathered' and will no longer be available for new build customers, customers who move into a property that has a time-of-use tariff or change from a flat rate tariff.

From 1 July 2024, new build customers and customers who move into a property that has a time-of-use tariff will have the choice of a regulated time-of-use tariff or a flat rate contract if they prefer a flat rate tariff.[24]

Existing customers on regulated flat rate tariffs and customers who move into a property that has a grandfathered tariff/s will be able to remain on those tariffs. Further, existing customers on regulated flat rate tariffs who upgrade to an advanced meter will also have the option of staying on their existing regulated flat rate tariff/s. However, if they decide to change tariffs, they will not be able to switch back to a regulated flat rate tariff.

10.3 Proposed approach

The Regulator proposes continuing to require Aurora Energy to submit a draft Standing Offer Tariff Strategy to cover the duration of the regulatory period under the 2025 Determination. The Regulator intends publishing the draft Tariff Strategy for consultation at the same time as consulting on the Regulator's investigation draft report during February and March 2025.

The Regulator will also be examining the structure of Aurora Energy's tariffs, including ensuring that suitable tariffs are available to customers for the next regulatory period.

While the Regulator notes that Aurora Energy will also be consulting on its Tariff Strategy, the Regulator is keen to seek initial views from stakeholders on the matters outlined below.

Subject to the magnitude of Aurora Energy's side constraints when seeking to adjust the fixed and variable components across its range of tariffs, should the Regulator consider other mechanisms to reduce customer impacts by introducing, for example, limits on the magnitude of the side constraints?

The Regulator is seeking feedback on Aurora's current approach to flat rate tariffs, with the grandfathering of existing standing offer flat rate tariffs and the introduction of a new contract flat rate tariff. In particular, the Regulator is seeking input on what information should be provided to customers so that they can understand and receive the benefit of a time-of-use tariff or determine if an alternative tariff is more suitable for their circumstances. Additionally, the Regulator is seeking feedback regarding whether there is a need for simpler tariffs.

[24] Aurora Energy, Residential prices, July 2024

11 PRICE APPROVAL PROCESS

11.1 Background

Under sections 40 and 41 of the ESI Act, Aurora Energy must obtain the Regulator's approval before fixing its standing offer prices and is not permitted to amend those prices unless approved by the Regulator.

Specifically, section 41 of the ESI Act states:

> **Approval of standing offer prices**
>
> (1) A standing offer price may not be fixed under section 40(1), and an amendment of a standing offer price may not be made under section 40(4), unless-
>
> (a) a draft of the standing offer price, or a draft amendment of the standing offer price, has been approved by the Regulator under subsection (3); and
>
> (b) the standing offer price fixed, or the draft amendment made, is in the same terms as the draft of the standing offer price, or the draft amendment of the standing offer price, approved by the Regulator under subsection (3).

11.2 Current approach

In the 2022 Determination, the Regulator decided on an annual approval process supported by a standing offer price approval guideline. The guideline sets out the information that Aurora Energy must provide in its annual standing offer pricing proposals. It also details the obligations of Aurora Energy and the Regulator regarding the approval of prices for each period, consistent with the provisions outlined in the ESI Act.

11.3 Issues

It is expected that Aurora Energy will continue its tariff rebalancing process within the regulatory period covered by the 2025 Determination. To ensure that stakeholders are aware of Aurora Energy's proposals, the Regulator intends amending the standing offer price approval guideline to require Aurora Energy to consult with stakeholders on the rebalancing of its tariffs and proposed side constraints as part of the annual price reset.

To improve transparency in the price approval process, the Regulator intends publishing the WEP once calculated, prior to approving standing offer prices in mid-June. The Regulator also intends publishing Aurora Energy's draft pricing proposal as soon as practicable upon its receipt. After the Regulator has reviewed Aurora Energy's draft proposal, the Regulator will publish a final version of Aurora Energy's proposal in mid-June in accordance with past practice.

11.4 Proposed approach

The Regulator proposes continuing to apply an annual price approval process supported by a standing offer price approval guideline.

As part of the guideline, the Regulator proposes requiring Aurora Energy to consult with stakeholders on any tariff rebalancing proposals and side constraints prior to the Regulator approving standing offer prices. The Regulator also proposes publishing its WEP once calculated and Aurora Energy's draft pricing proposal as soon as practicable.

The Regulator seeks feedback on its proposals to require Aurora Energy to consult with stakeholders on any tariff rebalancing proposals and on the Regulator publishing the WEP and Aurora Energy's draft pricing proposal as soon as practicable.

12 LENGTH OF REGULATORY PERIOD

12.1 Background

There is no specific statutory requirement for the Regulator to set the duration of the regulatory period until making the determination, which must specify both the commencement and expiry dates.

However, the Regulator considers that it would be desirable, prior to making the determination, to seek comments from stakeholders on the proposed duration of the next regulatory period.

12.2 Current approach

In the determinations made since 2007, the duration of each regulatory period has been set at three years. However, due to the impacts of the COVID-19 pandemic, the State Government extended the expiry date of the 2016 Determination to 30 June 2022, resulting in a regulatory period of six years.

12.3 Issues

There are costs and benefits arising from extending the duration of a regulatory period. Price determination investigations are time consuming and costly, with costs ultimately met by regulated customers. A longer regulatory period would therefore reduce those costs.

However, a longer regulatory period does not necessarily provide Aurora Energy with an incentive to pursue efficiency gains. In its 2022 Standing Offer Pricing Investigation Final Report, the Regulator found that during the extended 2016 Determination regulatory period, there had been a material increase in both labour costs and non-labour costs across Aurora Energy's business from 2017-18 to 2020-21.[25] In this instance, a shorter regulatory period would have given the Regulator the opportunity to review Aurora Energy's costs sooner than it was otherwise able to.

The energy industry in Australia is undergoing a period of significant change, which is being driven by the market as well as policy changes at both the state and federal levels. These changes together with increased retail competition in Tasmania, high rates of technological change, changing tariff structures and a number of large-scale energy projects for the State create considerable uncertainty.

The Regulator is seeking feedback on whether the next regulatory period commencing on 1 July 2025 should be of three or four years duration.

[25] Tasmanian Economic Regulator, *2022 Standing Offer Pricing Investigation Final Report*, page 27.

ATTACHMENT 1: GLOSSARY

Term	**Meaning**
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
Aurora Energy	Aurora Energy Pty Ltd, ABN 85 082 464 622
CARC	Customer acquisition and retention costs (costs incurred by a retailer in acquiring additional customers and retaining existing customers)
CER	Clean Energy Regulator
CPI	Consumer Price Index
DLF	Distribution Loss Factor
DMO	Direct Market Offer, as determined by the AER
Economic Regulator Act	*Economic Regulator Act 2009*
ESI Act	*Electricity Supply Industry Act 1995*
FRC	Full Retail Competition
Grandfathering	From a point in time, allowing customers on certain tariffs to remain on those tariffs while not offering those tariffs to new customers.
Guideline	Guideline - Standing Offer Price Approval Process in accordance with the 2022 Standing Offer Electricity Price Determination (29 April 2022)
GWh	Gigawatt-hour (one Gigawatt-hour is 1 000 Megawatt hours or 1 000 000 kilowatt-hours)
Hydro Tasmania	Hydro Electric Corporation, from 1 July 1998, ABN 48 072 377 158
ICRC	Independent Competition and Regulatory Commission, Australian Capital Territory

IPART	Independent Pricing and Regulatory Tribunal of New South Wales
kWh	Kilowatt-hour
LGC	Large-scale Generation Certificate
Load	Electricity consumed by electricity users
Load Following Swap	One of the types of financial contracts Hydro Tasmania is required to offer to retailers. The Regulator is required to use the LFS price in estimating Aurora Energy's WEP and, consequentially, its WEC.
LRET	Large-scale Renewable Energy Target
Mainland Tasmania	All parts of Tasmania other than any off-shore island of Tasmania (except for Bruny Island).
Market retail contract	A contract between a retailer and a small customer who decides not to remain on a standard retail contract. Terms and conditions in market retail contracts can vary from contract to contract.
MLF	Marginal Loss Factor
MW	Megawatt
MWh	Megawatt-hour
NEM	National Electricity Market
NER	National Electricity Rules
Next regulatory period	The regulatory period commencing on 1 July 2025
NMR	Notional maximum revenue. The Regulator allows Aurora Energy to recover these costs in its standing offer prices. That is, by applying the prices under each tariff to the billing days and load relating to the forecast number of customers under that tariff a notional amount of annual revenue is calculated for each tariff. The aggregate of this calculation for all tariffs must not exceed the Notional Maximum Revenue.
NTB	Notional Tariff Base, which comprises the customer.

	numbers and loads for all small customers connected to the distribution network that are eligible to take supply under a regulated tariff.
Price approval process	The process under which a regulated offer retailer submits its proposed standing offer prices for the Regulator's approval.
Price period	A 12-month period from 1 July to 30 June (e.g., Period 1, Period 2, Period 3) to which Aurora Energy's annual pricing proposal and the Regulator's associated price approval relate.
Pricing Regulations	*Electricity Supply Industry (Pricing and Related Matters) Regulations 2023*
QCA	Queensland Competition Authority
Regulated offer retailer	An authorised retailer who is declared to be a regulated offer retailer in accordance with an order made under section 38B(1) of the ESI Act.
Regulated tariff	A tariff to which a standing offer price, as approved by the Regulator, applies.
Regulator	The Tasmanian Economic Regulator, appointed under the Economic Regulator Act.
RET	Renewable Energy Target
RPP	Renewable Power Percentage
Small customer	Small customers are all residential customers and small business customers using less than 150MWh of electricity per annum.
SRES	Small-scale Renewable Energy Scheme
STC	Small-scale Technology Certificate
STP	Small-scale Technology Percentage
Standard retail contract	A contract under which a regulated offer retailer provides standard retail services to small customers. The retailer is unable to change the terms and conditions set out in a standard retail contract. A small customer electing not to enter

	into a market retail contract with a retailer receives supply under a standard retail contract.
Standard retail services	Services provided by a regulated offer retailer under standard retail contracts in respect of small customers.
Standing offer prices	The standing offer prices, fixed, or amended under section 40 of the ESI Act. Standing offer prices are approved by the Regulator under section 41 of the ESI Act.
Standing Offer Price Strategy	Document setting out Aurora Energy's intentions with respect to, among other things, the structure of its tariffs and rebalancing of its tariffs during the upcoming regulatory period.
TasNetworks	Tasmanian Networks Pty Ltd, ABN 24 167 357 299
WEC	Wholesale Electricity Cost
WEP	The Wholesale Electricity Price is estimated by the Regulator based on wholesale contract prices generated by the Wholesale Pricing Model in accordance with the requirements of the Wholesale Contract Regulatory Instrument using a method set out in the Regulator's Standing Offer Price Approval Guideline.
Wholesale Instrument	The instrument containing the approvals made by the Regulator from time to time under section 43G(1) of the ESI Act and Regulation 20 of the Pricing Regulations, having taken into account the principles set out in section 43H of the ESI Act.
Wholesale pricing model	The model developed by Concept Consulting Group Limited that is used to calculate the wholesale electricity price.

ATTACHMENT 2: LEGISLATIVE FRAMEWORK

The Regulator regulates electricity prices that Aurora Energy may charge small customers under standard retail contracts in accordance with the requirements set out in the ESI Act. Under this Act, Aurora Energy proposes, and the Regulator considers for approval, standing offer electricity prices.

Periodic pricing investigations are conducted by the Regulator in accordance with the process set out in the *Electricity Supply Industry (Pricing and Related Matters) Regulations 2023*.

Under Section 40AA of the ESI Act, the Regulator must determine the maximum prices that Aurora Energy may charge, or a method for determining those maximum prices. Further, under Regulation 12 of the Pricing Regulations, a price-regulated retail service price determination may be expressed in one or more of the following terms or manners:

(a) maximum prices or the maximum rate of increase or the minimum rate of decrease in maximum prices;

(b) average prices or average rates of increase or decrease in average prices;

(c) pricing policies or principles;

(d) by reference to a general price index, the cost of production, revenue, a rate of return on assets or any other factor;

(e) by reference to quantity, location or period of provision of the services to small customers under standard retail contracts;

(f) by reference to a maximum revenue; and

(g) any other terms the Regulator considers appropriate.

Section 40AB of the ESI Act requires the Regulator to estimate Aurora Energy's operational costs in providing standard retail services.[26] Section 40AB(2) specifies the components of Aurora Energy's operational costs that the Regulator must consider, including wholesale electricity costs, transmission and distribution costs, cost-to-serve and any other costs Aurora Energy incurs providing those services.

[26] These are the services provided by a regulated offer retailer under standard retail contracts in respect to small customers.