office of the tasmanian economic REGULATOR

RETAIL ELECTRICITY

STANDING OFFER PRICE METHODOLOGY REVIEW

DRAFT APPROACH PAPER

APRIL 2021

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MAKING A SUBMISSION

This draft Approach Paper provides stakeholders and interested parties with the opportunity to comment on the proposed methodology the Regulator intends using in making its determination of regulated retail electricity prices for the next regulatory period commencing on 1 July 2022 at the conclusion of the 2021-22 price investigation.

Submissions on the draft Paper close on 7 May 2021. The Regulator's proposals are summarised in Chapter 1 of this Paper.

Submissions may be mailed to the Regulator at:

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Alternatively, submissions may be emailed to the Regulator at: office@economicregulator.tas.gov.au.

Submitters are encouraged to make submissions in either Microsoft Word format or PDF (ie OCR readable text format rather than scanned copies so as the text is searchable).

Public consultation is a crucial element of the Regulator's processes and it is the Regulator's policy to publish written submissions received in response to consultation paper such as this Paper on the OTTER website.

A submitter may request that the submission, or part of it, be treated as confidential. The material for which a request of confidentiality is made should be clearly identified.

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

EXECUTIVE SUMMARY

Given the time that has elapsed since it made its last retail electricity price determination in May 2016, the Regulator decided in August 2020 to review the methodology it uses in determining Aurora Energy's retail electricity (standing offer) prices during its next price investigation and in its next price determination.

The Regulator's proposed approach to determining standing offer prices in its 2022 Standing Offer Price Determination (2022 Determination) is set out in this Paper. The Regulator will make the 2022 Determination after it completes its pricing investigation commencing on 1 July 2021.

This Paper summarises the Regulator's proposed approach to determining the maximum standing offer prices Aurora Energy, as the regulated offer retailer, can charge small customers in Tasmania (including Bruny Island) on standard retail contracts (regulated tariffs) for the supply of electricity from 1 July 2022 to 30 June 2015. This Paper does not apply to Aurora Energy's prices for customers on market retail contracts.

The Paper also compares the proposed approaches with the methods applied under the current, 2016 Standing Offer Price Determination.[1] It also sets out the Regulator's proposed approach to approving annual standing offer prices under the 2022 Determination.

The Regulator proposes retaining the cost build-up approach applied during the 2015-16 investigation and in the 2016 Determination. This methodology is used by other regulators responsible for retail electricity price regulation and is a well-established and accepted methodology with the components largely consistent across jurisdictions.

The applicable costs to provide retail services are:

- wholesale electricity costs (WEC);
- network costs;
- renewable energy target (RET) costs;
- metering costs;
- Australian Energy Market Operator (AEMO) costs; and
- Aurora Energy's retail operating costs (cost-to-serve).[2]

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

Under this approach, the costs set out above, together with a retail margin to compensate Aurora Energy for the risks it faces supplying retail electricity services to small customers on regulated tariffs, are summed to arrive at a notional revenue (the Notional Maximum Revenue or

[1] Tasmanian Economic Regulator, *2016 Standing offer price determination (2016 price-regulated retail services)*, amended June 2016.

[2] Under section 40AB(5) of the ESI Act, these costs are included to the extent that the Regulator considers they are reasonably incurred in the efficient provision of standard retail services.

NMR) for each year. The NMR is then used to derive maximum retail prices that Aurora Energy may charge during that year.

By scrutinising carefully all Aurora Energy's costs that would be reasonably incurred in the efficient provision of retail services, this approach seeks to ensure that customers on regulated tariffs pay no more than necessary for these services.

The cost-to-serve and retail margin cost components are determined by the Regulator. The WEC are based on the single wholesale electricity price for the following financial year which is calculated by the Regulator from wholesale financial contract prices using a method set out in the Regulator's Standing Offer Price Approval Guideline (Guideline). This wholesale electricity price is referred as the WEP and is determined in May each year for the following financial year.

RET costs are calculated based on parameters set by the Clean Energy Regulator (CER). The remaining costs are set by other bodies such as the Australian Energy Regulator (AER) and AEMO.

The Regulator's proposed approaches are summarised in Table 1. The Table also compares the proposed approach for estimating each cost component to the current approach.

Table 1: Costs and inputs - Comparison of current approach and proposed approach

Component	Current approach (2016 Determination)	Proposed approach for the 2022 Investigation and for the 2022 Determination
Overall approach	Cost build-up approach.	No changes are proposed to the overall approach.
Notional Tariff Base (NTB)		
Customer numbers	Aurora Energy is required to submit the actual customer number data (on regulated tariffs) reported to the Australian Energy Regulator for the quarter ending 31 March as part of the annual standing offer price approval process.	The Regulator proposes using a forecast of customer numbers 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. Forecast billing days must reconcile with forecast customer numbers that apply for each price period.
Load	Aurora Energy is required to submit details of its forecast load for each period in its pricing proposal as part of the annual standing offer price approval process.	No changes are proposed to the current approach although the Regulator will require the forecast load for each price period to be consistent with the forecast customer numbers that apply for that price period.
Cost Components		
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 to the current approach.
Wholesale electricity price (WEP)	The WEP is calculated in accordance with the ESI Act and the Guideline.	No changes are proposed to the current approach.
Network costs	The Regulator estimates network costs by multiplying the AER's approved network tariffs by forecast billing days and customer load for each	While the overall approach remains unchanged, the Regulator proposes that the billing days used in deriving network costs must reconcile with the forecast of the customer numbers used in the NTB.

	retail tariff, for the applicable period, and then summing the resultant values.	
Distribution Loss Factors (DLF)	The Regulator applied loss factors based on AEMO's published loss factors for the relevant period.	No changes are proposed to the current approach.
Marginal Loss Factors (MLF)	The Regulator applied loss factors based on AEMO's published loss factors for the relevant period.	No changes are proposed to the current approach.
Renewable energy target (RET) costs	The Regulator used the CER's published Renewable Power Percentages (RRP) for the first half of a financial year. For the second half of a financial year, the Regulator applied the RPP formula outlined in section 39(2)(b) of the *Renewable Energy (Electricity) Act 2000 (Cwlth)*. The Regulator uses the CER's Small-scale Technology Percentages. The Regulator has allowed Aurora Energy to recover its actual costs for both small scale technology and large scale generation certificates.	RET costs will be calculated on the same basis as the current approach except that the Regulator proposes using forward prices only when determining REC prices.
Metering costs	In estimating costs for metering services, the Regulator uses a weighted average cost of meters by tariff applied to the NTB. The Regulator also allows Aurora Energy to recover depreciation (over 6 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. The Regulator may approve prices to customers to recover metering costs that do not vary depending on customers' tariff/s or type of meter.	The Regulator is considering including in its 2022 Price Approval Guideline a requirement on Aurora Energy that the prices charged to a customer reflect the metering costs Aurora Energy incurs with respect to: • the tariff/s that customer is on; • whether that customer has an advanced (eg Type 4) meter or meters or an accumulation (Type 6) meter or meters; and • whether the advanced meter is replacing an accumulation meter that still has a useful life. The Regulator proposes that the billing days used in deriving metering costs must reconcile with the forecast of the customer numbers used in the NTB.
Cost-to-serve	A per customer cost-to-serve amount was derived during the 2016 price investigation using a combination of bottom up and benchmarking approaches.	The Regulator proposes continuing to express cost-to-serve on a $/customer basis but is considering an adjustment mechanism to account for variations in Aurora Energy's customer numbers. The adjustment mechanism would

	The cost-to-serve per customer also included an allowance for customer acquisition and retention costs. This value is indexed annually by the CPI with the indexed value used to calculate the NMR for the next price period.	operate independently of any annual indexation of Aurora Energy's cost-to-serve. This is to reflect the fact that some of Aurora Energy costs are fixed. The cost-to-serve would: ▪ increase on a $/customer basis if customer numbers are forecast to decrease; and ▪ decrease on a $/customer basis if customer numbers are forecast to increase.
Retail margin	During the 2016 price investigation the Regulator adopted a benchmarking approach to setting Aurora Energy's retail margin with the retail margin not changing during the regulatory period.	The Regulator is considering calculating the retail margin on a $/customer basis, rather than as a fixed percentage of all forecast costs.
AEMO costs	The Regulator applied AEMO's published fees and charges and a forecast of ancillary charges for the relevant period to the NTB.	Subject to the consideration of any changes arising from AEMO's *Electricity Market Participant Fee Structure Review*,[3] the Regulator does not propose any changes to its current approach to estimating AEMO costs. Aurora Energy will be required to express fees on a per connection point basis or on a $/MWh basis in line with how AEMO expresses its costs in its annual budget.
Adjustments for under and over recoveries	The difference between forecast and actual costs for each period are 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 proposes continuing to allow adjustments for under and over recovers in a price period in subsequent periods. The Regulator also proposes requiring under and over recoveries be calculated using the NTB in the relevant period, such that changes in volume (customer numbers and load) between periods will not be taken into account when calculating adjustments.
Adjustments for tax events and a material changes in Aurora Energy's costs	The Guideline includes a method to be used to calculate an adjustment amount under Regulations 12 and 16 of the Pricing Regulations.	No changes are proposed to the current approach.

[3] https://aemo.com.au/en/consultations/current-and-closed-consultations/electricity-market-participant-fee-structure-review

1 SUMMARY OF THE REGULATOR'S PROPOSED APPROACH

Description	Proposed changes in approach relative to current approach	Page reference/s in this Paper
Customer numbers	Use a forecast of customer numbers based on the mid-point of the actual customer numbers as at 31 March of the year prior to the commencement of each price period and a forecast as at 31 March during each price period. For example, for the 2022-23 price period, use the mid-point of actual customer numbers as at 31 March 2022 and forecast customer numbers as at 31 March 2023. Forecast billing days must reconcile with forecast customer numbers for each price period when estimating network costs and metering costs.	3.3 (page 15)
Load	The forecast load for the period must relate to the customer numbers forecast for that period.	3.3 (page 15)
Network	Billing days used in deriving network costs must be reconciled with the forecast customer numbers in the NTB.	5.4 (page 22)
RET	Forward prices to be used when determining LGC and STC prices.	6.3 (page 26)
Metering	The Regulator is considering including in its 2022 Price Approval Guideline a requirement on Aurora Energy that the prices charged to a customer reflect the metering costs Aurora Energy incurs with respect to: • the tariff/s that customer is on; • whether that customer has an advanced (eg Type 4) meter or meters or an accumulation (Type 6) meter or meters; and • whether the advanced meter is replacing an accumulation meter that still has a useful life. Billing days used in deriving metering costs must reconcile with the forecast of the customer numbers used in the NTB.	7.4 (page 29)
Cost-to-Serve	The Regulator is considering including an adjustment mechanism whereby the cost-to-serve allowance varies in accordance with customer numbers.	8.4 (page 32)
Retail Margin	The Regulator is considering calculating the retail margin on a dollar amount per customer, and including the resultant margin in the cost-to-serve.	9.4 (page 34)
AEMO	Fees and charges to be expressed on a per connection point basis or on a $/MWh basis as relevant and in line with how AEMO expresses the various costs in its annual budget.	10.2.3 and 10.3.3 (page 36)
Adjustments for over and under recoveries	Under and over recoveries are to be calculated using the NTB in the relevant period. That is, changes in volume due to customer numbers and load between periods will not be taken into account when calculating adjustments.	11.4 (page 39)

2 INTRODUCTION

Section 40AA of the *Electricity Supply Industry Act 1995* (the ESI Act) requires the Regulator to determine the maximum prices (or a method of determining the maximum prices) that Aurora Energy may charge small customers under standard retail contracts.

The current price determination, the *Aurora Energy Pty Ltd 2016 Standing Offer Price Determination* (2016 Determination), expires on 30 June 2022 and the Regulator is required to make a new price determination which will cover the regulatory period from 1 July 2022. Before making the new price determination, the Regulator is required to conduct a pricing investigation.

This Paper is part of the investigation process. It reviews the approaches and methodologies of previous determinations and sets out the Regulator's proposed approach for the next investigation and determination.

This review is particularly relevant as the 2016 Determination was made almost five years ago. During this period, the expiry date of the 2016 Determination has been extended twice by the Tasmanian Government. The regulatory framework has also been subject to various changes and interventions that have affected Aurora Energy's annual pricing proposals and the Regulator's assessment and approval of those proposals.

2.1 Legislative requirements

The Regulator regulates electricity prices that Aurora Energy may charge small customers[4] 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 2013* (Pricing Regulations).

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;

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

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.[5] 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.

2.2 Tasmanian context

The structure of the Tasmanian electricity market is significantly different from the market in other jurisdictions on mainland Australia. Compared to mainland Australia, Tasmania has a small number of major industrial customers that account for a relatively large share of electricity consumption.

State Government businesses own and operate the majority of electricity generation plants, all of the transmission network (excluding Basslink), and the distribution network. The State Government-owned Aurora Energy is also the dominant retailer with currently around 98 per cent of residential customers and 97 per cent of small business customers.[6]

Since full retail competition was introduced into mainland Tasmania on 1 July 2014, retailers other than Aurora Energy have been able to offer products to residential customers and small business customers.

Regulated prices provide a safety net price for small customers, and are the maximum prices that 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 is the only retailer required to offer regulated standing offer contracts.

The Regulator continues to be responsible for regulating Aurora Energy's standing offer prices. The Regulator's objectives under the ESI Act include promoting efficiency and competition while at the same time protecting the interests 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 reflects efficient costs. The entry of new retailers into the Tasmanian market (particularly the residential sector) has been relatively recent with 1st Energy entering the residential customer market in early 2019. During 2020, SocialEnergy and Energy Locals entered the residential, and residential and small business markets respectively during 2020.

2.3 Next steps and timeline

After considering feedback on this draft Paper, the Regulator will finalise the Paper and publish it on its website in June 2021. The final Paper will set out the approach the Regulator will apply in its 2021-22 pricing investigation and, consequentially, its 2022 Determination.

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

6 Based on data reported by retailers operating in Tasmania to the Australian Energy Regulator for quarter 2, 2020-21 (combined customer numbers for customers on standard retail contracts and customers on market offer contracts).

During the investigation the Regulator will consult on a draft investigation report and draft determination, Aurora Energy's Draft Standing Offer Price Strategy, and a draft standing offer price approval guideline.

The timeline for consultation on, and finalisation of, this Paper is set out in the following table.

Table 2.1 Timeline

Task Description	Date
Regulator releases draft Approach Paper	1 April 2021
Public consultation	1 April 2021 - 7 May 2021
Submissions due	7 May 2021
Regulator releases final Approach Paper	4 June 2021
Regulator commences pricing investigation	1 July 2021

3 DETERMINING MAXIMUM PRICES

3.1 Background

Under its current approach, the Regulator sets maximum prices using a cost build-up methodology. The cost build-up methodology, with minor differences, is used by other regulators to regulate electricity prices and is a well-established and accepted methodology. Furthermore, the individual cost components are consistent across jurisdictions.

3.2 Estimating the NMR

3.2.1 The Regulator's current approach

Maximum prices for regulated customers are currently determined by reference to a notional maximum revenue (NMR) applied to a Notional Tariff Base (NTB).

The maximum prices that Aurora Energy may charge in respect of small customers for the tariffs that are to apply in each period are determined in accordance with the following principle:

> If the price/s for each tariff were to be applied to the load and billing day schedule for the NTB for each tariff as provided by Aurora Energy and approved by the Regulator during the annual standing offer price approval process, for each of Periods 1, 2 and 3, the aggregate of the results so obtained will not exceed the notional maximum revenue calculated in accordance with clause 7 for the relevant period.[7]

In the 2016 Determination, the Regulator calculated the NMR for each year using the following formula:

$NMR_y = (WEC_y + NC_y + RET_y + M_y + R_y + AEMO_y + K_y) \times MARGIN_y + A_y + CF_y$

where:

$_y$	=	the relevant financial year, eg Period 1, Period 2 and Period 3.
NMR_y	=	the notional maximum revenue that Aurora Energy can receive and is calculated for each of years 1, 2 and 3 during the annual standing offer price approval process.
WEC_y	=	the forecast of wholesale electricity costs and is based on the wholesale energy price (WEP), forecast load and distribution and marginal loss factors.

[7] Tasmanian Economic Regulator, 2016 Determination, clause 6(c), 5 May 2016.

NC_y	=	forecast network costs. Network costs comprise two components: transmission and distribution charges, both of which are regulated by the AER. TasNetworks' relevant regulated network tariffs are multiplied by the applicable forecast billing days and customer load to determine the total network cost component of the NMR.
RET_y	=	the forecast cost of Aurora Energy complying with the Australian Government's mandatory renewable energy schemes.
M_y	=	the forecast of allowed metering costs.
R_y	=	Aurora Energy's cost-to-serve.
$AEMO_y$	=	the total of Aurora Energy's forecast market participant fees and ancillary service charges, as set by AEMO.
K_y	=	an aggregate of approved under and/or over recoveries for network costs, metering costs, RET and AEMO under the current determination.
$MARGIN_y$	=	the retail margin and intended to compensate Aurora Energy for the investment it makes in its retail business and for the risks it assumes in providing retail services to small customers under standard retail contracts.
A_y	=	an adjustment made as a result of a tax event, a material change in circumstances or a material change in Aurora Energy's costs in relation to the provision to small customers under standard retail contracts.
CF_y	=	an aggregate of under and/or over recoveries from the previous period covered by the previous determination and includes the margin applicable under the previous determination.

3.2.2 The Regulator's proposed approach

The Regulator proposes to continue with the current cost build-up method of determining maximum standing offer prices as it meets the legislative requirements with regard to determining maximum standing offer prices, it is transparent and relatively simple.

3.3 Customer numbers and load

Customer numbers and customer load are used in estimating a number of the cost components that are, in turn, used in determining maximum prices.

3.3.1 The Regulator's current approach

Under the Regulator's current approach, customer numbers and load are referred to as the Notional Tariff Base (NTB). To enable the calculation of maximum prices, the NTB is shown as a schedule that includes tariffs, load by energy step, billing days and, if applicable, a demand step. The NTB schedule is set out as follows:

Tariff	Energy Step 1	Energy Step 2	Energy Step 3	Energy Peak	Energy Shoulder	Energy Off-peak	Billing Days	Demand Step 1

Billing days are used to calculate fixed charges and are calculated by multiplying the number of customers on a particular tariff by the number of days in the price period. Billing days are calculated for all tariffs that have a fixed daily charge and are multiplied by the relevant fixed daily charge to determine the cost component amount.

The NTB relates to standing offer customers on mainland Tasmania only (including Bruny Island) and therefore excludes load associated with:

- customers on a market retail contract; and
- customers on the Bass Strait Islands.

These customers and their associated loads were excluded from the forecast NTB to ensure that standing offer customers are not cross -subsidising these customers.

For the 2016 pricing investigation, the Regulator changed its previous approach of relying on a forecast of customer numbers for the next price period, to using actual customer numbers at a point in time, and accounting for a change in customer numbers in retrospect rather than in advance. The change was due partly to the Regulator's concerns about the accuracy of forecasts, and partly due to all customers in Tasmania having the option of choosing an unregulated market contract if offered. With the introduction of competition, the forecast customer numbers needed to factor in customers changing to and from market retail contracts. This made forecasting customer numbers increasingly difficult. The Regulator therefore decided to use, for the following year, the customer numbers as at 31 March as provided by Aurora Energy to the AER each year.

The NTB and its components are used in calculating the components of the NMR as shown in the following table.

Table 3.1 Use of customer numbers and customer load in calculating NMR components under the 2016 Determination

Cost component	Customer load and customer numbers	Customer numbers	Customer load
Network costs	X		
Metering costs		X	
Wholesale electricity costs			X
AEMO costs	X		
RET costs			X
Cost-To-Serve		X	

These customer numbers are also used in calculating billing days in relation to network costs and metering costs.

In June, prior to the commencement of each price period, the Regulator, as part of the annual standing offer price approval process, approves the NTB to be used in calculating the NMR for the applicable period. As explained above, the Regulator currently estimates a NTB comprising the number of small customers as at 31 March and a forecast of the relevant load. Aurora Energy is required to provide an updated NTB for the Regulator's approval during the annual standing offer price approval process.

3.3.2 The Regulator's proposed approach

The Regulator proposes continuing to use an NTB to refer to customer numbers and load. However, under the Regulator's current approach, different customer numbers are used to calculate different cost components. The Regulator considers that all cost components that relate to customer numbers, which includes load and billing days, should be calculated on a consistent basis.

In making this proposal the Regulator considers it undesirable for different customer numbers to be used to calculate different cost components as it may impact on prices. Unlike the load which is an estimate of the electricity consumed during one year, customer numbers are referenced to a point in time.

The Regulator considers that, rather than fixing customer numbers for the following year as at March of the current year, it is preferable to use a forecast of customer numbers. Options include forecasting customer numbers at the start of the relevant year, the end of the relevant year and taking the mid-point, or taking the mid-point of actual customer numbers as at 31 March before each year and a forecast as at 31 March during the year.

The Regulator proposes using 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.

The Regulator also proposes that billing days for network costs and metering costs are reconciled to this forecast of customer numbers.

The Regulator further proposes that the load in the NTB is 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. It is necessary for the forecast total load to be the sum of the forecast load forecast for each tariff.

4 WHOLESALE ELECTRICITY COSTS

4.1 Background

Currently, the estimate of the wholesale energy costs (WEC) component of the NMR is based on the wholesale electricity price (WEP), forecast customer load, 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 as calculated are specified in the Wholesale Contract Regulatory Instrument (Instrument). The Instrument documents a rules- based methodology for calculating the prices for each contract type in the wholesale pricing model which is a Microsoft Excel model.

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

4.2 The Regulator's current approach

4.2.1 The wholesale electricity price

In its 2016 Determination, 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 the year. The method used under the 2016 Determination is as follows:

(a) for those weeks where Hydro Tasmania is not required to offer regulated contracts, the respective Absolute Minimum Capacity Offer Volume will be set to zero ;

(b) multiply the weekly regulated LFS price by the weekly Absolute Minimum Capacity Offer Volume for that quarter for eight quarters preceding the start of each quarter of the relevant period;

(c) use the weekly point-in-time LFS price for each quarter of the relevant period at the time that the Economic Regulator calculates the WEP for all future weeks remaining in each quarter for which there are no regulated LFS prices; and

(d) divide the sum of the values calculated in accordance with clauses 7.1(2)(b) and 7.1(2)(c) by the sum of the weekly Absolute Minimum Capacity Offer Volumes for the eight quarters preceding the start of each quarter of the relevant period.

4.2.2 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 grossed up (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)[8] 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 to apply to the following financial year.

4.2.3 Load

The load used in calculating the WEC for each price period is a forecast load as per the NTB for that price period. Section 2.4 explains the Regulator's proposed approach to estimating the load.

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
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

4.3 What other regulators do

To estimate future wholesale electricity costs in the cost build-up, the ICRC, QCA and ESC all 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

[8] Also referred to as the TLF (Transmission Loss Factor).

futures prices, multiplied by an uplift factor that compensates for the spot price volatility risk in the NEM. The ICRC engages a consultant, Frontier Economics, to assist with calculating these costs.

4.4 The Regulator's proposed approach

The Regulator considers that the current method of calculating the WEP is a market-based, transparent method which complies with the requirements of Section 40AB(3) of the ESI Act.

The Regulator proposes continuing with the current weighted average method to calculate the WEP for the regulatory period to be covered by the 2022 Determination.

The Regulator proposes no change to how loss factors are calculated. The applicable load will be as set out in the NTB discussed in Section 2.4

In calculating the WEC and the NMR for each year, the Regulator proposes requiring Aurora Energy to adopt the loss factors published by AEMO for each financial year of the regulatory period. Furthermore, as part of the annual standing offer price approval process in June, Aurora Energy will submit, for the Regulator's approval, a weighted average DLF and MLF which will be used in calculating the WEC for the following year.

As occurs under the 2016 Determination, the Regulator proposes that the WEP is determined as part of the annual standing offer price approval process in June each year prior to the start of each period. The calculated WEP will then be used to calculate the WEC as part of the calculation of Aurora Energy's NMR.

5 NETWORK COSTS

5.1 Background

Network costs comprise transmission use of system (TUoS) and distribution use of system (DUoS) charges

Only those network costs relating to services provided to customers on standard retail contracts are included in the network cost component of Aurora Energy' cost build-up.

5.2 The Regulator's current approach

Network costs are regulated by the AER with the AER reviewing TasNetworks schedule of tariffs in June each year. 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 charge based on demand. Network tariffs are grouped by network tariff classes. Network tariff classes are based on the physical characteristic of the electricity connection (eg high voltage) or customer type (eg residential or business).

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.

If for some reason the charges are not known when the NMR must be calculated (eg if AER did not approve TasNetworks' charges in time) network costs would need to be based on an estimate of the charges (such as based on TasNetworks' draft price proposal) for the next year and then an adjustment would have to be made in the subsequent year for the difference between the estimate and the actual charges. Adjustments are discussed in more detail in Chapter 11.

5.3 What other regulators do

The approach taken by the ICRC, ESC and QCA in relation to network costs is that the AER sets the network costs and these costs are passed through to electricity retailers 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 that forecast.

5.3.1 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.

5.3.2 QCA

Where the underlying network tariff structure is similar to an existing retail tariff the QCA uses the applicable network prices approved by the AER in determining regulated retail prices.

Where, for historical reasons, the retail tariff is different from the network tariff eg the underlying network tariff has materially changed or is non-existent, the QCA uses an indexation approach. Under this approach the previous year's network costs are modified by applying the relevant AER nominal X-factors used for revenue smoothing for transmission and distribution businesses. The resultant network tariffs are then applied in the cost build-up of individual tariffs.

5.3.3 ESC

The ESC's Victorian Default Offer regulated electricity prices vary 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 uses the simplest network tariff in each zone ie a daily supply charge ($ per day) and a usage charge ($ per kWh) in determining prices for that zone.

5.4 The Regulator's proposed approach

The Regulator proposes to continue to with the current approach to forecast network costs. However, the Regulator proposes reconciling the billing days used in deriving network costs with the forecast of the customer numbers used in the NTB ie the billing days used when forecasting network costs are to relate directly to the number of customers forecast in the NTB.

6 RENEWABLE ENERGY TARGET COSTS

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 tradable 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. 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 electricity 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 amount of wholesale electricity purchased by the retailer in a calendar year adjusted for the applicable Distribution Loss Factor (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 amount of electricity purchased (or liable MWh).

6.1 The Regulator's current approach

This section sets out the Regulator's current approach to estimating LRET costs, SRES costs and liable MWh.

6.1.1 Large-scale Renewable Energy Target costs

The formula for estimating the LRET costs is as follows:

LRET cost = (RPP x $/LGC x liable MWh)

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 2016 Determination, the Regulator uses 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 uses 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.

The Regulator requires Aurora Energy to use the latest available forecast LGC price.

The amount of liable MWh is discussed below in section 6.1.3.

6.1.2 Small-scale Renewable Energy Scheme costs

The formula for estimating the SRES costs is 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 2016 Determination, the Regulator uses 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 uses the CER's non-binding STP.

The Regulator requires 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.

6.1.3 Amount 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 (ie 1 July to 31 December) and the second half of the financial year (ie 1 January to 30 June).

Based on advice provided by Aurora Energy as to the seasonality of demand, under the 2016 Determination the Regulator allocates 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.

6.2 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.

6.2.1 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 an 11-month period. The ICRC determines an overall environmental cost component by applying 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 recognises that there are costs associated with holding these certificates prior to their surrender. 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. In its methodology review, the Commission decided to include a green scheme certificate holding cost allowance in its pricing model.

The allowance reflects the cost of debt for half a year because, in the Commission's view, a prudent retailer would, on average, buy certificates evenly throughout the year. The Commission considered that it would be appropriate to use a cost of debt for businesses with a credit rating of Baa2, the credit rating held by AGL and Origin Energy at the time of ICRC's methodology review.

LRET and SRES obligations accrue in calendar year terms while the Commission's pricing model operates on a financial year basis. LRET and SRES costs for a financial year are derived therefore by apportioning calendar year costs based on the half-yearly load weights provided by ActewAGL.

6.2.2 QCA

QCA uses a consultant, currently ACIL, to estimate LRET costs using a market-based approach. Under this approach, LGC prices are based on forward prices for certificates published by the Australian Financial Markets Association. ACIL 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 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.

6.2.3 ESC

The ESC accounts for 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.

6.3 The Regulator's proposed approach

The Regulator proposes continuing with the current approach to calculating Aurora Energy's forecast RET costs including calculating the liable MWh by splitting the forecast load between the first and second half of each financial year based on its analysis, during the 2021-22 pricing investigation, of Aurora Energy's demand data.

However, compared to its current approach, in estimating the price of LGCs and STCs, the Regulator proposes using forward prices for each price period at a point in --time close to the time when standing offer prices are approved for the following period. The Regulator may need to engage a consultant or purchase data to estimate forward prices.

Furthermore, as discussed in Section 11.4, if Aurora Energy's actual RET prices over the year are different from the forward prices, this would not be included in any adjustments for over or under recoveries.

7 METERING COSTS

7.1 Background

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

Changes to the National Electricity Rules (NER) to provide for metering competition from 1 December 2017 included creating a new role, that of Metering Coordinator. 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. Retailers are responsible for engaging a Metering Coordinator for their small customers. The changes to the NER also require 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 which measure the total electricity consumed over a period and require manual reading. Each tariff requires a separate meter therefore customers with on Tariffs 41 and 31 (most residential customers are on this combination) will have two type 6 meters. The Local Network Service Provider, TasNetworks continues to be responsible for reading these meters.

- Advanced meters, also referred to as interval or Type 4 meters, record usage in real time and are read in 15 or 30 minute intervals. These meters are also able to record usage against multiple tariffs and can be read remotely. Aurora Energy has contracted Yurika (previously Metering Dynamics) to manage the installation, maintenance and reading of Type 4 meters.

7.2 The Regulator's current approach

Prior to the introduction of metering competition, and to provide greater transparency in the presentation of the costs of providing retail electricity services to small customers, the Regulator added a separate cost component in the NMR formula for Metering Costs (My) in its 2016 Standing Offer Determination.

Under the 2016 Determination, the Regulator has approved Aurora Energy using a weighted average calculation of metering costs per tariff multiplied by the appropriate number of billings days to forecast its metering costs.

All new and replacement meters are advanced meters and eventually all accumulation meters will be replaced with advanced meters. Customers may also choose to change to an advanced meter. Although the cost of an advanced meter is substantially higher than that of an accumulation meters, all small customers pay the same metering amount as there is no difference in prices for customers irrespective of the type of meter they have.

Under the 2016 Determination the Regulator has 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 an advanced meters.

b) the ongoing annual capital cost associated with accumulation meters that have been replaced by advanced meters ie in accordance with the AER's distribution determination for the period 1 July 2019 to 30 June 2024,[9] TasNetworks is permitted to recover the remaining capital costs of these meters where they have a remaining useful life (ie depreciation);

c) depreciation associated with capital expenditure required to meet the set up costs associated with the start of metering competition (costs to be written off over 6 years commencing from 1 December 2017); and

d) fee based metering services recovered on an annual basis.[10]

7.3 What other regulators do

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

7.3.1 ICRC

Prior to its 2020 price determination, the ICRC did not include the costs of advanced meters in its electricity pricing model. This meant that the regulated standing offer tariffs were based on basic meter costs only and excluded the cost of providing advanced meters to individual customers. Consequently, ActewAGL recovered the costs of advanced meters for standing offer customers by applying a higher supply charge to customers who had an advanced meter. In other words, ActewAGL did not spread (or 'smear') advanced meter costs across the regulated customer base because this cost was not in the ICRC's cost stack. For this reason, ActewAGL applied two sets of supply charges - one set for advanced meter customers and another for basic meter customers.

In its 2020 price determination, the ICRC included advanced meter costs (including installation and advanced meter reading costs) in ActewAGL's allowances. The ICRC considered that it would be fairer to customers to 'smear' advanced meter costs across the regulated base. In addition, advanced meter costs are likely to increase over time as the number of advanced meters increases. Delaying the inclusion of advanced meters in the cost build-up is likely, ceteris paribus, to result in a larger price increase when they are included.

7.3.2 QCA

The QCA does not allow notified prices to residential and small business customers to recover metering costs (including installation and meter reading costs). This is because under Queensland's *Electricity Act 1994*, these charges cannot be included in notified prices. However, Ergon Energy, the regulated retailer, is able to charge customers a meter service charge which is separate to notified prices (ie these charges appear on a customer's bill as a separate item). For large customers, the QCA does make an allowance for the metering costs in regulated prices. These costs are based on the latest confidential data provided by retailers.

7.3.3 ESC

The ESC does not include a separate cost component for metering when determining annual VDOs. 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

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

[10] For example, a remote site service surcharge for travel outside the metro area.

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 network costs.

7.4 The Regulator's proposed approach

With respect to metering costs, the Regulator has considered the costs and benefits to customers arising from the introduction of advanced (eg Type 4) meters in Tasmania, the arrangements and experience in other jurisdictions, and the pricing of meter-related costs under market contracts in Tasmania.

The Regulator is considering including in its 2022 Price Approval Guideline a requirement on Aurora Energy that the prices charged to a customer reflect the metering costs Aurora Energy incurs with respect to:

- the tariff/s that customer is on;
- whether that customer has an advanced (eg Type 4) meter or meters or an accumulation (Type 6) meter or meters; and
- whether the advanced meter is replacing an accumulation meter that still has a useful life.

This may be presented as a separate meter charge on customers' bills or the meter-related costs may be included in other charges on customers' bills, such as in a (daily) supply charge.

Customers' bills would reflect more closely the costs Aurora Energy pays for the metering services provided to those customers. This would also enable customers to make a decision about the merits or otherwise of choosing to have an advanced meter installed based on the full costs Aurora Energy incurs, and so whether the expected benefits to the customer exceed these costs. It may also influence a customer's decision whether or not to agree to the installation of an advanced meter under a retailer-led meter rollout program.

This would mean that a customer pays for the extra costs associated with an advanced meter in all circumstances, namely:

- a new installation;
- for premises where an Aurora Energy customer has previously requested, or requests, an advanced meter;
- for premises if the customer's Type 6 meter was, or is, faulty and the meter was, or is, replaced by an advanced meter; or
- for premises where the customer agreed, or agrees, to the installation of an advanced meter under a retailer-led meter rollout program.

Under this option, from 1 July 2022, customers with a Type 6 meter would face lower electricity bills than under the current approach, while customers with an advanced meter would face higher electricity bills than under the current approach, all other factors held constant. However, customers with an advanced meter may be able to access tariffs and/or manage their consumption and make savings on their electricity bills.

The method for calculating metering costs will be set out in the Regulator's draft investigation report and/or draft Determination.

8 COST-TO-SERVE

8.1 Background

The cost-to-serve accounts for the operating costs of providing retail services and includes:

- billing and revenue collection;
- marketing;
- providing advice and answering customer queries via its customer call centre;
- contributing to corporate overheads; and
- regulatory compliance.

The cost-to-serve allowance is generally expressed on $ per customer basis.

8.2 The Regulator's current approach

Cost-to-serve are typically estimated using one or both of the following approaches:

- benchmarking; and
- retail operating cost build-up.

In the retail electricity sector, benchmarking involves comparing a retailer's cost-to-serve allowance with the recent allowances approved by regulators in other Australian jurisdictions. In comparison, a bottom up approach involves conducting a detailed review of the retailer's operating cost structure to arrive at what the Regulator considers to be a reasonable cost-to-serve amount.

Due to a lack of comparable retailers, the Regulator used a combination of benchmarking and bottom up approaches in determining a cost-to-serve allowance for the 2016 Determination. The Regulator estimated Aurora Energy's cost-to-serve allowance via a cost build-up approach and then compared the result against the cost-to-serve amount in the Australian Capital Territory and Queensland.

Customer acquisition and retention costs (CARC) are the costs incurred by retailers in contestable markets where new entrant retailers endeavour to attract customers away from incumbent retailers and incumbent retailers seek to both retain existing customers and attract new customers.

The cost-to-serve allowance included a CARC allowance on the assumption that Aurora Energy would be operating in a competitive market. The Regulator's primary consideration was to ensure that the cost to serve allowance reflected the efficient costs associated with operating in such an environment.

The retail cost components calculated by the ICRC, ESC and QCA all include a CARC.

The annual cost-to serve is indexed by movements in the Australian Consumer Price Index (CPI).

8.3 What other regulators do

The ICRC, ESC and QCA use a variety of methods in determining retail costs.

8.3.1 ICRC

The ICRC has indexed retail costs to CPI movements since 2014. The 2014 allowance for retail operating costs was based on a benchmark review by IPART in 2012-13[11]. At the time, IPART determined an efficient retail operating cost for a standard retailer (on a per customer basis)[12]. This involved undertaking a bottom up analysis, using information provided by retailers operating in NSW on their historic, current and forecast retail operating costs, and adjusting the results to remove costs recovered elsewhere , such as costs associated with late bill payment as these are recovered through a late payment fee.

As discussed in its latest price determination[13], the ICRC considered that the resulting retail operating cost allowance was consistent with those identified by the ACCC Inquiry into the National Electricity Market[14] and the Frontier Economics report to the ESC on retail operating costs.[15]

8.3.2 ESC

In estimating retail costs on a per customer basis, the ESC relies on the decision made by the ICRC in its 2017 price determination. These costs are adjusted for inflation and include an allowance to reflect additional costs associated with operating in Victoria. As described in section 8.3.1 above, the ICRC's 2017 (and 2020) benchmark was originally derived from IPART's 2012-13 benchmarking review.

8.3.3 QCA

The QCA undertook a comprehensive review of retail costs as part of its 2016–17 price determination. The assessment used a combination of bottom-up and benchmarking methods, using information from public sources (including retail market offers) and confidential information from retailers. Separate retail costs are applied to the fixed and variable cost components of retail prices.

In determinations since then, the QCA has updated its 2016 17 cost estimates in the following ways:

- the fixed cost allowance has been adjusted for the forecast change in the CPI; and
- the variable retail cost percentage allocation has been maintained at 2016–17 levels.

8.4 The Regulator's proposed approach

The Regulator proposes continuing to use a combination of cost build-up and benchmarking approaches in determining Aurora Energy's cost-to-serve allowance for the next regulatory period.

Applying these approaches, the Regulator proposes to estimate Aurora Energy's cost-to-serve allowance via a cost build-up approach and then compare the result against the cost-to-serve

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11 IPART 2013, *Review of regulated retail prices and charges for electricity – Final Report*.

12 IPART defines a standard retailer as an incumbent retailer that has achieved economies of scale; serves retail customers; can offer retail customers standard form and negotiated customer supply contracts; and has an existing customer base to defend.

13 ICRC 2020, *Retail Electricity Price Investigation 2020-2024 - Final Report.*

14 ACCC 2019, *Inquiry into the National Electricity Market*.

15 Frontier Economics 2019, *Retail costs and margin: A report for the Essential Services Commission.*

amount used in other jurisdictions. Compared to 2016, there are now additional cost-to-serve figures to benchmark against such as those set out in the ACCC Inquiry into the National Electricity Market[16] and the Frontier Economics report to the ESC on retail costs.[17]

The Regulator acknowledges that if Aurora Energy's customer numbers change, Aurora Energy will have more or fewer customers from which to recover its fixed costs attributable to providing services under standard retail contracts. The Regulator is therefore considering including an adjustment mechanism whereby, separate from any annual indexation arrangement, Aurora Energy's cost-to-serve allowance per customer would increase if customer numbers are lower in the next year, or decrease if its customer numbers are higher.

The Regulator also proposes allowing Aurora Energy to continue recovering CARC relating to defensive campaigns and advertising costs it incurs in response to new retailers operating in the Tasmanian retail electricity market. These costs will be aggregated with other retail operating costs in calculating Aurora Energy's cost-to-serve allowance.

In accordance with past practice, for the second and third year of the regulatory period, the Regulator proposes indexing the first years' cost-to-serve allowance by applying an inflation factor.

[16] https://www.accc.gov.au/publications/inquiry-into-the-national-electricity-market-september-2020-report

[17] Essential Services Commission, Victorian Default Offer to apply from 1 July 2019, Advice to Victorian Government, 3 May 2019, page 50.

9 RETAIL MARGIN

9.1 Background

The retail margin is intended to compensate Aurora Energy for the risks it faces providing standard retail services to customers on standard retail contracts.

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 adopted in other jurisdictions.

9.2 The Regulator's current approach

In 2016, the Regulator adopted a benchmarking approach to setting the retail margin, taking account of the risks Aurora Energy faced in delivering retail services under standard retail contracts. That is, the retail margin took into account the differences in risks faced by Aurora Energy compared to the risks faced by the benchmark retailers.

The Regulator adopted this approach because it was not convinced at the time that an alternative methodology such as a detailed bottom-up approach would deliver significant benefits over a benchmarking approach. The Regulator considered that the costs of the alternative approach would likely outweigh the benefits. The Regulator also considered decisions made in New South Wales, the Australian Capital Territory and Queensland in relation to the 2015-16 financial year.

9.3 What other regulators do

The ICRC and ESC both apply a retail margin to all costs whereas the QCA includes a retail margin in retail costs.

9.3.1 ICRC

The ICRC uses a benchmarking approach when determining the retail margin. In its 2020 determination, the ICRC also took into account the retail margins discussed in Frontier Economics report to the ESC and the ACCC Inquiry into the National Electricity Market. Frontier Economics' benchmarks were based on the regulatory allowances used by the QCA (in 2015), the ICRC (in 2014), OTTER (in 2016) and IPART (in 2013). The ACCC inquiry reported on the margins applied by electricity retailers in each jurisdiction for 2018-19.

In its 2020 determination, the ICRC also considered other factors, including the current downward trend for wholesale energy prices, which it considered warranted an increase in the retail margin on the basis that this trend represents an increased (wholesale price) risk to retailers. The ICRC assessed that the increase in the retail margin percentage would ensure that the dollar value of the retail margin would remain a reasonable profit margin. ActewAGL's current retail margin is 5.6 per cent.

9.3.2 ESC

The ESC also uses a benchmarking approach based on recent decisions by Australian energy regulators to estimate a retail margin. At 5.7 per cent, the ESC's most recent margin is comparable to the margin estimated by the ICRC.

9.3.3 QCA

The QCA's model does not have a specific allowance for a retail margin. Rather, the margin is included as part of retail costs. The QCA considered it unnecessary to estimate an efficient retail margin. Instead, the QCA's approach focuses on estimating an efficient total level of retail costs, which implicitly includes some retail margin, portions of which are recovered through fixed and variable charges.

In previous determinations, the QCA applied a retail margin allowance, which was based on the retail margin adopted by IPART in 2012-13. In 2016-17, the QCA decided it would no longer rely on benchmarking of other regulators' decisions to estimate retail costs, given that a number of jurisdictions (including NSW and South Australia) had removed retail price regulation. The QCA also considered that reliance on other regulatory decisions generates circularity, which could lead to regulatory error over time.

9.4 The Regulator's proposed approach

The Regulator intends to take the same approach as in the 2016 Determination, namely adopting a benchmarking approach to setting the retail margin, taking account of the risks Aurora Energy faced in delivering retail services under standard retail contracts.

This will take into account the energy price risks that Aurora Energy may face in Tasmania compared with retailers operating in interstate markets. If the Regulator includes in the cost-to-serve allowance an adjustment mechanism based on changes in customer numbers, this would also be taken into account.

As the retail margin is currently applied to the sum of the cost components, an increase in costs leads to a bigger retail margin in dollar terms and vice versa. There appears to be no justifiable basis for the total retail margin varying directly with Aurora Energy overall costs. It means, for example, that if WEP or network costs rise, Aurora Energy's NMR would increase not just due to the higher WEP or network costs but also by applying the margin to the sum of the cost components which would not be related to, for example, Aurora Energy facing greater risks. To mitigate against this outcome, the Regulator is therefore considering calculating the retail margin on a dollar amount per customer basis and including this amount as part of the cost-to-serve.

If this approach is adopted, a method for calculating a retail margin on a dollar amount per customer would be set out in the Regulator's draft investigation report and/or draft Determination.

10 AEMO COSTS

10.1 Background

The Australian Energy Market Operator (AEMO) 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 and are permitted to be recovered from their customers:

- 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.

Retailers are also permitted to recover from their customers AEMO costs relating to payments for ancillary services. These fees 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.

10.2 AEMO fees

10.2.1 The Regulator's current approach

Under the 2016 Determination, the Regulator estimates 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.

10.2.2 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. Both the ICRC and QCA calculate the AMEO fee portion of their pricing models using observed AEMO cost data for the first year of the regulatory period, with subsequent years indexed by the CPI. The ESC, in contrast, estimates AEMO market fees using an average of the previous year and estimates for the year to which AEMO fees will apply.

10.2.3 The Regulator's proposed approach

Subject to a consideration of any changes arising from AEMO's Electricity Market Participant Fee Structure Review,[18] and in accordance with previous determinations, the Regulator proposes to continue its current approach to estimating NEM fees, FRC electricity fees.

However, from 2020-21, national transmission planner fees are not borne by market customers; instead they are payable by transmission network service providers and reflected in network costs. These fees will, therefore, no longer be included in the AEMO component of the cost build-up (these fees were not included in the AEMO component for 2020-21 nor will they be for 2021-22 under the 2016 Determination).

10.3 Ancillary Services

10.3.1 The Regulator's current approach

Under the 2016 Determination, the Regulator estimates 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.

10.3.2 What other regulators do

To estimate ancillary fees, both the ESC and QCA use an average of the past 52 weeks of AEMO's ancillary service payments. In its first year of the regulatory period, the ICRC also uses this approach. For the subsequent years of the regulatory period, the ICRC indexes these costs by the CPI.

10.3.3 The Regulator's proposed approach

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

[18] https://aemo.com.au/en/consultations/current-and-closed-consultations/electricity-market-participant-fee-structure-review

11 ADJUSTMENTS

11.1 Background

As explained in Section 3.2 of this Paper, the prices to apply to the next price period are currently calculated using an NMR 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.

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 actual RPP and the STP 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 from the prices charged during a price period as they may not reflect the actual per unit costs incurred during that period.

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.

11.2 The Regulator's current approach

To address the issue that some costs may not be known at the time prices are approved, the Regulator allows the difference between forecast cost components and the actual costs to be included in the NMR formula in the Ky and CFy cost components when calculating maximum standing offer prices for subsequent price periods.

The difference between forecast and actual pass through per unit costs will be included in Ky if the costs relate to a period covered under a current price determination, or CFy if the costs relate to a previous price determination.

Under and/or over recoveries included in Ky or CFy cost components are limited to cost components determined by third parties ie 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 set.

Under the Regulator's current approach and in accordance with the 2016 Determination, Aurora Energy is permitted to include under and over recoveries in relation to network costs, AEMO fees, RET costs and metering costs.

The Regulator seeks to keep under and over recoveries to a minimum. Partly this is because a slightly different set of customers benefit through lower prices (return of a past over recovery reduces the NMR all other things being equal and therefore leads to relatively lower prices) or is penalised (requirement to pay higher prices due to an under recovery which increases the NMR all other things being equal and therefore leads to relatively higher prices) relative to the group of customers that paid the prices approved for the earlier price period. Also these under and over recoveries can contribute to larger price variations between years.

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

The method to calculate Ay is specified in the Guideline and states:

> (a) if the adjustment is due to an error, or omission[19], 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); and
>
> (b) in all other cases, the adjustment is to be calculated using a method approved by the Regulator.

The adjustment may include an allowance for the applicable retail margin.

11.3 What other regulators do

The adjustment mechanisms used by other regulators differ.

11.3.1 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, load and the contract position.
- 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 (the cost adjustment is 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 Clean Energy Regulator). The ICRC's annual recalibration for LRET and SRES costs is not an over or under recovery of the actual costs that ActewAGL has incurred in the previous year.
- The ICRC also updates the costs associated with advanced meters (to account for the difference between forecast and actual costs in the previous year).

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

In undertaking the annual price recalibration process, the ICRC also allows for a regulatory change or tax change event review. A regulatory change event is a decision made before or during a regulatory period that has the effect of materially varying the nature, scope, standard or risk of providing services to regulated retail tariff customers. A tax change event means the imposition of a relevant tax, the removal of a relevant tax, or a change in the way a relevant tax is interpreted or calculated.

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

11.3.2 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,[20] and was sufficiently material to impact the benchmark established for the efficient costs to supply an electricity retail service.

11.3.3 QCA

As discussed in Chapter 6, 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 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.

11.4 The Regulator's proposed approach

The Regulator proposes continuing to allow the difference between forecast per unit costs and actual per unit costs for each price period to be passed through to small customers in the next period through the inclusion of K_y and CF_y components in the calculation of the NMR.

Further, the Regulator proposes that under and/or over recoveries included in the K_y or CF_y costs :

- continue to be limited to network costs, metering costs, RET costs and AEMO charges and
- apply only to the extent that the relevant cost component per unit price is not known at the time prices are set for the next price period.

To calculate the applicable K_y and CF_y the Regulator will require the relevant cost component to be recalculated using the NTB for that year but with the updated values for that year ie reflecting what the NMR component value would have been if the actual cost had been known at the time the prices were approved. With regard to RET costs, the Regulator proposes only updating the RPP and STP but not changing LGC and STC prices. With regards to ancillary charges the Regulator proposes to apply a rate, calculated using the actual ancillary fess for the price period, to the load in the NTB for that period.

At the time prices are calculated for the next year, the actual values are not known for the last quarter of the then current price period. To account for this timing difference, the adjustments to a NMR component for a price period will need to be recovered over the next two price periods. Firstly, a preliminary adjustment in which the difference between the initial value and the updated component value is included in the NMR for the next price period in K_y and CF_y (if applicable). Secondly, a final adjustment in which the difference between the previous years recalculated component and the final actual value for the cost component. As such K_y and CF_y (if applicable) will include adjustments for two previous price periods.

The Regulator proposes no changes to the current approach to calculating A_y. The Price Approval Guideline will set out how the Regulator intends calculating these adjustments.

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

12 STANDING OFFER PRICE STRATEGY

12.1 Background

The Regulator required Aurora Energy to submit a Standing Offer Price Strategy for the regulatory period covered by the 2016 Determination. Aurora Energy was required to set out its intended changes to its existing tariff structure, standing offer prices and details of any price transition mechanisms it intended applying during the current regulatory period.

Before submitting its Strategy, Aurora Energy was also required to provide high level principles that would underpin the Strategy. These principles set out Aurora Energy's desire to have flexibility in its standing offer prices in order to be able to compete with other retailers.

Among other things, Aurora Energy's Strategy proposed its approach to price changes, which involved passing through price changes based on changes in specific underlying NMR cost components and incremental rebalancing for each component of each tariff to address disparities in tariffs created during previous regulatory periods. The Regulator approved the Strategy on 5 May 2016.

12.2 The Regulator's proposed approach

For the 2021-22 price investigation, the Regulator proposes requiring Aurora Energy to submit for approval a Standing Offer Price Strategy that will apply for the regulatory period to be covered by the 2022 Determination. The Regulator does not propose requiring Aurora Energy to submit, separately, the high level principles that would underpin its Strategy as the Regulator will require the Strategy itself to set out those principles.

Among other things, the Regulator expects that the Strategy will set out Aurora Energy's plans on a range of issues including but not limited to meeting shareholder directives and expectations, the structure of its tariffs (including the extent to which its non-electricity related costs may be recovered from fixed daily charges) and any rebalancing of standing offer prices.

13 ANNUAL PRICE APPROVALS

13.1 Background

Standing offer electricity prices are commonly set on an annual basis to allow for changes in both costs and the NTB as well as variations between forecasts and actual cost inputs.

In the Tasmanian context, sections 40(1) and 40(4) respectively of the ESI Act allow Aurora Energy, as a regulated offer retailer, to fix or amend its standing offer prices provided the prices fixed or amended are approved as per section 41.

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).

13.2 The Regulator's current approach

Clause 5 of the 2016 Standing Offer Determination requires:

> Draft standing offer prices …to be submitted to the Regulator for approval in accordance with the *Electricity Supply Industry Act 1995* and the annual standing offer price approval process.

The annual standing offer price approval process is outlined in the Regulator's standing offer price approval guideline.[21] The Guideline sets out Aurora Energy's obligations including the timeframes for the submission of its annual standing offer pricing proposals. The Guideline also sets out the Regulator's responsibilities under the 2016 Standing Offer Determination and its approach to calculating the annual WEP and estimating Aurora Energy's customer numbers and load (the NTB).

13.3 What other regulators do

13.3.1 ICRC

As discussed in Chapter 11, the ICRC carries out an annual recalibration of the cost component parameters. Based on the information gathered via this process, the ICRC determines the

[21] The current version is the *Guideline: Standing offer price approval process in accordance with the 2016 Standing Offer Price Determination*, December 2020.

percentage by which the weighted average price change may be adjusted by for the following year. The Commission provides its direction to ActewAGL by 5 June each year.

13.3.2 QCA

Regulated electricity prices in regional Queensland are set annually by the QCA. Prior to approving prices for the upcoming financial year, the QCA consults publicly on a draft determination.

13.3.3 ESC

While the ESC sets VDOs bi-annually, retailers covered by the AER's DMO and the ESC's VDOs do not submit their proposed prices to the respective regulators for approval. Instead retailers must ensure that the proposed prices, when multiplied by usage and after adding daily supply charges, do not result in a customer's annual bill exceeding the relevant DMO or VDO.

13.4 The Regulator's proposed approach

Given the specific legislative requirements in Tasmania and having considered the arrangements in place in other jurisdictions, the Regulator proposes continuing with an annual approval process supported by a standing offer price approval guideline.

In accordance with past practice, the Regulator intends releasing a draft of the guideline for public consultation during the 2021-22 price investigation. The guideline will set out Aurora Energy's obligations and, if required, provide more detail on the Regulator's proposed approach to estimating Aurora Energy's cost components and inputs including but not limited to the WEP and the NTB.

14 LENGTH OF REGULATORY PERIOD

14.1 Background

There is no specific statutory requirement for the Regulator to set the duration of the regulatory period until he makes his 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 and interested parties on the proposed duration of the next regulatory period.

14.2 The Regulator's current approach

In the determinations made since 2007, the duration of each regulatory period has been set at three years. However, while the 2016 Determination was initially set for three years, the Government has extended the expiry date of the 2016 Determination in November 2018 by two years to 30 June 2021 and, in December 2020, by a further year to 30 June 2022. The current determination will therefore have been in force for six years by the time the next price determination commences on 1 July 2022.

14.3 The Regulator's proposed approach

There are costs and benefits of increasing 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.

In light of the uncertain economic climate, the dynamic nature of the retail electricity market, technological change and increasing level of competition for residential customers, a longer timeframe may not be prudent.

The Regulator proposes, consistent with past practice, that the next regulatory period run for three financial years, ie from 1 July 2022 to 30 June 2025.

APPENDIX A: ABBREVIATIONS AND ACRONYMS

Term	**Meaning**
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
Aurora Energy	Aurora Energy Pty Ltd, ABN 85 082 464 622
Authorised retailer	A person holding a retailer authorisation under the NERL
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
Economic Regulator Act	*Economic Regulator Act 2009*
ESI Act	*Electricity Supply Industry Act 1995*
FRC	Full Retail Competition
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 (LFS)	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
NEL	National Electricity Law
NERL	National Energy Retail Law, as applied in Tasmania by the National Energy Retail Law (Tasmania) Act 2012
NEM	National Electricity Market
NER	National Electricity Rules
Next regulatory period	The regulatory period commencing on 1 July 2022
NMR	Notional maximum revenue
NTB	Notional Tariff Base. The notional tariff base 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 (eg 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 2013*
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
Regulator	The Tasmanian Economic Regulator, appointed under the *Economic Regulator Act 2009*
RET	Renewable Energy Target
Retailer authorisation	Authorisation issued by the AER under the National Energy Retail Law. Unless exempt from the requirement, a person

	must hold a retailer authorisation prior to engaging in the retail sale of energy.
RPP	Renewable Power Percentage
Small customer	A customer who is a small customer under the NERL
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	TasNetworks Pty Ltd, from 1 July 2014, ABN 24 167 357 299
Treasury	The Tasmanian Department of Treasury and Finance
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 Contract Regulatory 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 for Treasury that is used to calculate the wholesale electricity price.

2013 Determination	The determination made in accordance with Regulation 22C of the *Electricity Supply Industry (Price Control) Regulations 2012.*