Wentworth to Broken Hill Pipeline

Attachment 9

Frontier Economics report on electricity costs

30 September 2025

WaterNSW Broken Hill Pipeline – Energy costs

A report for WaterNSW | 15 July 2025

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1 Introduction

WaterNSW is currently preparing its *2026-2031 Pricing Proposal* for the Independent Pricing and Regulatory Tribunal (IPART) for the water transportation services it provides via the Broken Hill Pipeline to Essential Water to meet the needs of the community of Broken Hill. These prices will apply from 1 July 2026 to 30 June 2031.

The costs of energy required to pump and transport water via the pipeline form a key element of the notional revenue requirement used to derive the prices levied on Essential Water and other customers of the pipeline.

In making its 2022 Broken Hill Pipeline Determination, IPART decided:

- To set a forecast energy cost allowance using:
  - Observed operational data to determine the energy required to pump water
  - An IPART model that sought to optimise the timing of using energy to pump water to minimise wholesale energy costs
  - Forecasts of the key components associated with the cost of purchasing energy including benchmark wholesale energy costs, renewable energy costs, network charges and Australian Energy Market Operator (AEMO) charges.
- To develop a true-up mechanism in collaboration with WaterNSW that accounts for the key risks in forecast energy costs and appropriately balances energy cost risk between WaterNSW and its customers.

Consistent with IPART's 3Cs framework, the *2026-2031 Pricing Proposal* requires:

- an estimate of the costs of energy required to pump and transport water via the pipeline for the 2026-2031 period;
- the development of a true-up mechanism to estimate the over/under-recovery relative to the energy cost allowances in the 2022 Determination ('looking back'), and the true-up amount to be applied in the 2026 Determination to ensure WaterNSW and customers are no 'worse off'
- a proposed true-up mechanism that can be applied in the next Determination to account for over/under-recovery of energy costs relative to the energy cost allowances in the 2026 Determination.

1.1 Our engagement

As part of the preparation of the *2026-2031 Pricing Proposal*, WaterNSW engaged Frontier Economics to advise on energy costs for the pipeline for the period from 1 July 2026 to 30 June 2031.

Specifically, we have been engaged to:

- Work with WaterNSW to collect relevant electricity usage data to assess how much electricity is used, and when electricity is used, in supplying transportation services using the Broken Hill Pipeline;
- Estimate electricity costs for the Broken Hill Pipeline, including each relevant component of electricity costs: wholesale electricity costs, renewable energy policy costs, market fees and ancillary services costs, retail operating costs and margins and network charges;

- Provide the inputs for the development of a true-up mechanism to estimate the over/under-recovery relative to the energy cost allowances in the 2022 Determination;
- Identify the factors that may cause electricity costs to vary over the upcoming five-year determination period and recommend a methodology for calculating an electricity true-up to manage the risks of variations in electricity costs.

1.2 This report

This report is structured as follows:

- Section 2 describes the methodology, inputs and results for the forecast energy consumption for FY27 to FY31.
- Section 3 describes the methodology, inputs and results for the forecast energy costs for FY27 to FY31.
- Section 4 provides inputs into the calculation of a true-up mechanism, and provides our view on a true-up mechanism for the 2026 Determination period.

2 Forecasting energy consumption

To forecast the electricity costs that WaterNSW will face for Broken Hill Pipeline it is first necessary to forecast the amount of electricity that WaterNSW will use to operate the Broken Hill Pipeline. Because electricity prices vary by time of day, it is necessary to forecast both the total amount of electricity that WaterNSW will use each year and the times that WaterNSW will use that electricity. Both of these forecasts should reflect efficient operation by WaterNSW.

2.1 Estimating pumping volumes

The starting point for forecasting the electricity use for the Broken Hill Pipeline is to forecast the amount of water to be supplied through the pipeline each year of the regulatory period.

WaterNSW has provided a forecast of pumping volumes for the Broken Hill Pipeline for each year of the regulatory period. This forecast is based on the assumption of normal weather conditions occurring in each year. The pumping forecast provided by WaterNSW is set out in Table 1.

Table 1: Forecast of volume of water pumped

Financial Year	Unit	FY27	FY28	FY29	FY30	FY31
Volume of water pumped	ML/a	6495.1	6497.1	6498.2	6500.3	6502.3

Source: WaterNSW

2.2 Estimating pumping profiles

To estimate the time of day that water pumping will occur to meet these forecasts of annual water pumping we make use of historical data on electricity used for pumping. This half-hourly electricity data provides a detailed picture of the time of day that pumping has occurred.

WaterNSW has provided half-hourly electricity used for water pumping that is based on electricity meter reads. This half-hourly data was provided for the full financial years for each year from FY19 to FY24, as well as for part of FY25.

To estimate pumping profiles for the FY27 to FY31 we use the half-hourly electricity use for FY24 as a starting point. FY24 is the most recent full financial year of data that we have available, and also had a total volume of water pumped – 5,826.7 ML – that is reasonably well-aligned with the forecast volumes of water pumped (as seen in Table 1).

Taking the half-hourly electricity use for FY24, for each day in FY24 we calculate the amount of electricity use that occurred in peak periods, shoulder periods and off-peak periods on that day. The definitions of peak periods, shoulder periods and off-peak periods that we use is the definition used for WaterNSW's electricity network tariff. The result of this is an estimate, for each day of FY24, of the proportion of daily water pumping that occurred in peak, shoulder and off-peak periods.

We assume that these same proportions will apply for each of the forecast years from FY27 to FY31. To convert these proportions into pumping quantities for in each period (peak, shoulder and off-peak) in each day, we do the following:

- We slightly shift the sequence of historical daily outcomes from FY24 to match the sequences of weekdays/weekends in the forecast year. This is because the day of the week is important for the definition of peak, shoulder and off-peak periods, and each year starts with a different day of the week (for instance, the first day of FY24 was a Saturday but the first day of FY27 is a Thursday).

- We adjust the daily pumping quantity from FY24 to the equivalent day in the forecast year by scaling the daily pumping quantity from FY24 to account for the difference in total annual pumping between FY24 and the forecast year. Since the total annual pumping quantity in FY24 was slightly lower than the forecast total annual pumping quantities for each forecast year, this adjustment involved a slight scaling up of the FY24 daily pumping quantities.
- The resulting implied daily pumping quantities for each day of the forecast year are then allocated to peak, shoulder and off-peak periods based on the calculated proportion of pumping that occurred in these periods in the equivalent day in FY24. However, in doing so, we ensure that where the forecast year has more daily pumping that the equivalent day in FY24, the allocation of this greater amount of daily pumping to each period does not result in more pumping occurring in a given period that is technically possible. For instance, if the equivalent day in FY24 already has pumping occurring at the maximum rate for all off-peak periods, then any additional daily pumping in the forecast year cannot be allocated to off-peak periods but has to be allocated to shoulder periods.

The result of these steps is an estimate of pumping in peak, shoulder and off-peak periods in each day of each year of the forecast period.

2.3 Estimated electricity use

Electricity use is estimated based on the estimated water pumping profiles, and applying a pumping energy requirement of 1.6391 MWh/ML, the value used in IPART's previous determination.

Multiplying the estimate of pumping in peak, shoulder and off-peak periods in each day of each year of the forecast period by this amount of 1.6391 MWh/ML provides an estimate of electricity use in MWh in peak, shoulder and off-peak periods in each day of each year of the forecast period.

These estimates of electricity use can then be summed to determine total peak, shoulder and off-peak electricity use for each year of the forecast period and also used to determine peak demand in peak, shoulder and off-peak periods for each year of the forecast period.

These amounts do not include fixed energy use. Fixed energy use is calculated based on the assumption of 0.6 MWh/d, the value used in IPART's previous determination. This fixed energy use is assumed to occur at a constant rate throughout the year, and is allocated to peak, shoulder and off-peak periods on that basis.

2.4 Summary of results

Following this approach provides the results for electricity consumption (in MWh) shown in Table 2 and the results for peak demand (in MW) shows in Table 3.

Table 2: Estimated electricity consumption

	2027	2028	2029	2030	2031
Total consumption (MWh)	10,643.56	10,653.73	10,651.78	10,653.94	10,651.03
Total variable (MWh)	10,424.56	10,434.13	10,432.78	10,434.94	10,432.03
Total Fixed (MWh)	219.00	219.60	219.00	219.00	219.00
Total Off-peak (MWh)	7,758.12	7,767.54	7,779.82	7,780.44	7,759.67
Total Shoulder (MWh)	2,701.79	2,709.66	2,695.31	2,695.78	2,703.98
Total Peak (MWh)	183.65	176.53	176.65	177.73	187.37

Source: Frontier Economics analysis

Table 3: Estimated peak electricity demand

	2027	2028	2029	2030	2031
Off-peak: Peak half-hour (fixed + variable) (MW)	1.83	1.83	1.83	1.83	1.83
Shoulder: Peak half-hour (fixed + variable) (MW)	1.83	1.83	1.83	1.83	1.83
Peak: Peak half-hour (fixed + variable) (MW)	0.88	0.86	0.86	0.86	0.88

Source: Frontier Economics analysis

3 Forecasting energy costs

To develop independent forecasts of efficient electricity costs for the Broken Hill Pipeline we consider the costs that an electricity retailer would face in supplying electricity to WaterNSW for the Broken Hill Pipeline. These costs are:

- Wholesale electricity purchase costs.
- Energy losses.
- Unaccounted for energy (UFE).
- Network costs.
- Environmental costs (the costs of complying with environmental and renewable energy policies, including the Small-scale Renewable Energy Scheme [SRES], the Large-scale Renewable Energy Target [LRET] and the NSW Energy Savings Scheme [ESS]).
- Market fees and ancillary services costs.
- Retail operating costs and margin.

We calculate and provide a recommendation on the efficient benchmark price of energy for the Broken Hill Pipeline *for each year* over the 2026 Determination period.

The following sub-sections detail the methodology and data used to calculate our estimates of the efficient benchmark price for each of the retail electricity price components listed above.

All inputs and results presented are in real financial year 2025/26 dollars ($FY26), unless otherwise stated. Where required, historical consumer price index data for Australia published by the Australian Bureau of Statistics (reference period *March Quarter 2025*) has been obtained and used.[1] June 2025 annual inflation is assumed to be 2.0%, based on IPART advice. Annual inflation for June 2026 and June 2027 is assumed to be 2.7% and 2.5%, respectively, based on IPART advice. Inflation for June 2028 and beyond is assumed to be 2.5%.

3.1 Wholesale electricity purchase costs

Our approach to forecasting wholesale electricity costs for 1 July 2026 to 30 June 2031 aligns with the methodology accepted by IPART in the 2022 Determination.[2]

The methodology for forecasting wholesale electricity involves:

1. Using electricity contract prices reported on ASX Energy[3] to calculate wholesale electricity prices for those years for which contracts are currently trading. ASX Energy Base Strip futures contracts data was obtained for FY27 and FY28.[4] Contracts are available for FY29 however these were excluded from the analysis as minimal contracts had been traded at the time of undertaking this analysis. A 40-day average price (for the 40 business days prior to and inclusive of 30 June 2025) was calculated for contracts for each of FY27 and FY28. Contract prices were then constant in real terms for FY29, FY30 and FY31.

[1] Australian Bureau of Statistics, *Consumer Price Index, Australia – March Quarter 2025*, April 2025, https://www.abs.gov.au/statistics/economy/price-indexes-and-inflation/consumer-price-index-australia/latest-release

[2] IPART, *Review of WaterNSW's prices for the Murray River to Broken Hill Pipeline Final Technical Report,* November 2022.

[3] ASX Energy, *The Australian Power Market*, *https://www.asxenergy.com.au/*

[4] Data was retrieved 1 July 2025.

2. Calculating an estimated spot price in each year by adjusting the forward contract prices for an assumed 5% contract premium.
3. Using actual half-hourly regional reference prices for NSW for FY25, obtained from *NEMWEB* market data portal,[5] and the estimated spot prices from step 2, a scaled regional reference price for each half-hour for each year was calculated. This half-hourly prices were then used to determine average peak, shoulder and off-peak prices for each year, using the relevant network definitions of peak, shoulder and off-peak periods. Combining these peak, shoulder and off-peak prices with electricity use in peak, shoulder and off-peak periods enables the calculation of an annual load weighted average electricity price for that electricity use. Dividing this annual load weighted average electricity price by the annual time weighted average electricity price results in the load premium, which is a simple measure of how much higher or lower than annual average prices is the average price of meeting the defined electricity use.
4. The final estimate for wholesale energy costs in each year was then calculated by adjusting the spot price estimated in step 2 for the load premium calculated for that year, and then adding a contract premium of 5%.

Table 4 details the key results. Generally speaking, the results show that contract prices are around $110/MWh, implying spot prices around $105/MWh. A load premium of around 76% suggests that the pumping profile enables an average load-weighted electricity price that is only 76% of the average time-weighted electricity price, which results in an estimate of wholesale electricity costs (including the contract premium) of around $83/MWh.

Table 4: **Wholesale electricity purchase cost forecasts, annual ($FY26/MWh)**

	FY27	FY28	FY29	FY30	FY31
Contract prices	$113.73	$110.35	$110.35	$110.35	$110.35
Spot price	$108.32	$105.10	$105.10	$105.10	$105.10
Load premium	76.01%	75.93%	75.92%	75.93%	76.05%
LWP	$82.33	$79.81	$79.79	$79.81	$79.93
Wholesale energy cost	**$86.45**	**$83.80**	**$83.78**	**$83.80**	**$83.93**

Source: Frontier Economics

3.2 Energy losses

The estimated wholesale electricity purchase costs presented above must be adjusted to account for transmission and distribution losses associated with transmitting electricity to an end-user.

We use estimates of distribution losses and transmission losses published by AEMO. Estimates of distribution losses were obtained from AEMO's *Distribution Loss Factors for the 2025/26*

5 AEMO, *Market Data: NEMWeb*, Accessed 3 July 2025, https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/data-nem/market-data-nemweb

Financial Year[6] report. Estimates of transmission losses were obtained from AEMO's *Marginal Loss Factors: Financial Year 2025-26*[7] report.

Consistent with the 2022 Determination, the relevant estimate of distribution losses is the Essential Energy High Voltage Distribution Loss Factor (DLF).

For transmission losses, we have utilised the same demand weighted average approach as the 2022 Determination. As Table 5 shows, we have held the weightings the same as the 2022 Determination for the Red Cliff and Broken Hill connection points, and updated the Marginal Loss Factor's (MLF) for the most recent data.

Table 5: Estimated Marginal Loss Factor

TNI	TLF Region	Weighting	MLF
VRC2	Red Cliffs	8.64%	0.9952
VRCA	Red Cliffs	57.09%	0.9967
NBKH	Broken Hill	31.40%	0.9267
NBKH	Broken Hill	2.88%	0.9267
Marginal Loss Factor Input (weighted average)			**0.9726**

Source: Frontier Economics

In the absence of long-term forecasts of relevant DLFs and MLFs, we have assumed that the DLF and MLF remain constant over the modelling period (see Table 6).

Table 6: Estimated total loss factor

	FY27	FY28	FY29	FY30	FY31
MLF	0.9726				
DLF	1.0248				
Total loss factor	**0.9967**	**0.9967**	**0.9967**	**0.9967**	**0.9967**

Source: Frontier Economics

The cost of these energy losses is then estimated based on the estimated wholesale electricity cost forecasts (detailed above in Table 4) and the total loss factors presented in Table 6. Table 7 details forecast energy loss costs on an annual basis.

6 AEMO, *Distribution Loss Factors for the 2025/26 Financial Year*, April 2025, https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/loss_factors_and_regional_boundaries/2025-26-marginal-loss-factors/distribution-loss-factors-for-the-2025-26.pdf?la=en

7 AEMO, *Marginal Loss Factors: Financial Year 2025-26*, June 2025, https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/loss_factors_and_regional_boundaries/2025-26-marginal-loss-factors/marginal-loss-factors-for-the-2025-26-fin-year.pdf?la=en

Table 7: Forecast energy loss costs, annual ($FY26/MWh)

	FY27	FY28	FY29	FY30	FY31
Losses	-$0.29	-$0.28	-$0.28	-$0.28	-$0.28

Source: Frontier Economics

3.3 Unaccounted for energy

In December 2018, the Australian Energy Market Commission published a rule that required a move to a global settlement framework from a settlement by difference framework for the demand side of the wholesale electricity market.[8] The global settlements framework fully commenced in May 2022.

The global settlement framework means all retailers in a distribution area are allocated an a share of unaccounted for energy (UFE). That is, under the global settlement framework, every retailer is now billed for the loss-adjusted metered electricity that is consumed by their customers within the area. The UFE is then allocated to retailers in the area, pro-rated based on their 'accounted-for' energy.[9]

Given UFE only fully commenced in May 2022, a UFE cost component was not included in the energy benchmark published in the previous Determination[10]. The remainder of this section details the data and method by which UFE charges over the modelling period were estimated.

UFE trend data was obtained from AEMO[11]. UFE data is currently available for the period 26 February 2023 to 1 March 2025. Given UFE trends exhibit seasonality and the limited historical data available, the sampling period used to calculate a UFE proportion was constructed to be 2 full-years of daily data using the most recent data available (that is, 2 March 2023 to 1 March 2025 inclusive).

UFE as a proportion of ADME (aggregate metered energy multiplied by the DLF) was calculated on a daily basis for this 2-year period for the relevant profile area ('*COUNTRYENERGY*'). The average UFE proportion over was ~2.61%. The cost of UFE was then estimated based on the estimated wholesale electricity cost forecasts (Table 4) and the estimated UFE proportion (held constant over the modelling period).

Table 8 details forecast UFE costs on an annual basis.

[8] Australian Energy Market Commission (AEMC), Global settlement and market reconciliation, n.d., https://www.aemc.gov.au/rule-changes/global-settlement-and-market-reconciliation

[9] AEMC, Global Settlement and Market Reconciliation, December 2018, https://www.aemc.gov.au/sites/default/files/2018-12/Global%20settlement%20infosheet%20and%20example.pdf

[10] WaterNSW, *Pricing Proposal to the Independent Pricing and Regulatory Tribunal: Regulated prices for the Wentworth to Broken Hill Pipeline,* 30 June 2021.

[11] AEMO, Unaccounted for Energy (UFE) Information and Reports, Accessed 15 June 2025, https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/data-nem/metering-data/unaccounted-for-energy-ufe-information-and-reports

Table 8: Forecast UFE costs, annual ($FY26/MWh)

	FY27	FY28	FY29	FY30	FY31
UFE costs	$2.25	$2.18	$2.18	$2.18	$2.19

Source: Frontier Economics

3.4 Network costs

Across the National Electricity Market, electricity networks (both transmission and distribution) are considered to be natural monopolies and are subject to economic regulation by the Australian Energy Regulator (AER).

For the purpose of estimating network costs, we have assumed that – consistent with IPART's previous Determination[12] – the relevant Broken Hill Pipeline network tariff is the Essential Energy BHND3AO network tariff class.

Table 9 below details the tariffs for Essential Energy's BHND3AO network tariff class for FY26, taken from Essential Energy's AER approved network prices for 2025-26[13].

Table 9: Essential Energy 2025-26 BHND3AO network tariff ($FY26)

Charge	Unit	Value
Network access	$/day, $FY26, ex. GST	25.54
Energy Peak	c/kWh, $FY26, ex. GST	4.64
Energy shoulder	c/kWh, $FY26, ex. GST	3.77
Energy off peak	c/kWh, $FY26, ex. GST	3.10
Demand peak	$/kVA/M, $FY26, ex. GST	11.27
Demand shoulder	$/kVA/M, $FY26, ex. GST	10.19
Demand off peak	$/kVA/M, $FY26, ex. GST	3.05

Source: Essential Energy, Network Price List and Explanatory Notes 2025-26

These FY26 network charges were rolled out across FY27, FY28 and FY29 using the X-factors from the Post-Tax Revenue Model published as part of the AER's April 2024 Final Decision for the *Essential Energy distribution Determination 2024-29*[14]. Table 10 details these X-factors[15].

12 IPART, *Review of WaterNSW's prices for the Murray River to Broken Hill Pipeline Final Technical Report,* November 2022.

13 Essential Energy, *Network Price List and Explanatory Notes 2025-26*, https://www.essentialenergy.com.au/-/media/Project/EssentialEnergy/Website/Files/Our-Network/PriceListAndExplanatoryNotes2025-26.pdf?rev=fdaf5254fafd4bc6a154284ee9226d44

14 AER, *Final decision - Essential Energy distribution Determination 2024-29 - PTRM - April 2024*, April 2024, https://www.aer.gov.au/industry/registers/determinations/essential-energy-determination-2024-29/final-decision

15 Note: A negative X-factor implies a real price increase.

Table 10: Essential Energy distribution X-factors, FY27-FY29 (%)

	FY27	FY28	FY29
X Factors	-2.85%	-2.85%	-2.85%

Source: AER, Final decision – Essential Energy distribution Determination 2024-29 - PTRM - April 2024, April 2024

Table 11 details the average network charges accounting for the X-factors presented above. Given that there is no published X-factors for FY30 or FY31, tariffs are held constant in real terms at the FY29 rate.

Table 11: Forecast network charges ($FY26)

Charge	UoM	FY27	FY28	FY29	FY30	FY31
Network access	$FY26/day	$26.27	$27.01	$27.78	$27.78	$27.78
Energy Peak	$FY26/MWh	$47.70	$49.06	$50.46	$50.46	$50.46
Energy shoulder	$FY26/MWh	$38.73	$39.83	$40.97	$40.97	$40.97
Energy off peak	$FY26/MWh	$31.86	$32.77	$33.70	$33.70	$33.70
Demand peak	$FY26/kVA/M	$11.59	$11.92	$12.26	$12.26	$12.26
Demand shoulder	$FY26/kVA/M	$10.48	$10.78	$11.09	$11.09	$11.09
Demand off peak	$FY26/kVA/M	$3.14	$3.23	$3.32	$3.32	$3.32

Source: Frontier Economics

3.5 Environmental costs

An electricity retailer supplying electricity to WaterNSW for the Broken Hill Pipeline must incur costs associated with complying with environmental and renewable energy policies, including the Large-scale Renewable Energy Target (LRET), the Small-scale Renewable Energy Scheme (SRES), and the NSW Energy Savings Scheme (ESS). This section presents our approach to estimating the costs of complying with these environmental and renewable energy policies.

3.5.1 LRET compliance costs

The LRET places a legal liability on wholesale purchasers of electricity – including retailers – to proportionately contribute to the generation of renewable electricity from large-scale renewable electricity generators up to a specified target by purchasing and surrendering Large-scale Generation Certificates (LGCs).[16] An LGC is created by eligible renewable energy power stations for each MWh of renewable energy they produce. The number of LGCs to be purchased by liable

[16] Clean Energy Regulator, *Large-scale Renewable Energy Target*, https://cer.gov.au/schemes/large-scale-renewable-energy-target

entities each year is determined by the Renewable Power Percentage (RPP), which is published each year by the Clean Energy Regulator[17].

In order to calculate the cost to a retailer to WaterNSW of complying with the LRET, it is necessary to determine the RPP for the retailer (which determines the number of LGCs that must be purchased) and the cost of obtaining each LGC.

Renewable Power Percentage

The RRP establishes the rate of liability under the LRET and is used by liable entities to determine how many LGCs they need to surrender to discharge their liability each year. The RPP is set to achieve the renewable energy target specified in the legislation. We have used the published RRP for 2025 (17.91%).

This RPP has been held constant over the modelling period consistent with the previous Determination's approach, with the exception of FY31. The LRET scheme is scheduled to cease operation at the end of calendar year 2030. Therefore, to reflect this in the modelling we have utilised an RPP of half of the current 17.91% RPP, such that the RPP is 8.96% in FY31.

Cost of obtaining LGCs

We have utilised publicly available data on the market price of LGCs to estimate the cost to a retailer of obtaining LGCs. LGC forward contract prices reported on DemandManager were extracted. This prices were used to calculate a 40 day weighted average LGC forward contract price (using the 40 business days prior to and inclusive of 30 June 2025) for each year from FY27 to FY30.[18] These prices were then adjusted to $FY26. No data is currently available for FY31, so the forward price was held constant in real terms for FY31.

Table 12 presents the estimated LGC forward prices utilised to calculate the costs of complying the with LRET.

Table 12: Estimated LCG forward price

	Unit	FY27	FY28	FY29	FY30	FY31
Estimated LGC Forward Price	$ Nominal	$17.41	$14.04	$10.41	$9.13	$9.13
Estimated LGC Forward Price	$FY26/MWh	$16.98	$13.36	$9.67	$8.27	$8.07

Source: Frontier Economics

Cost of complying with the LRET

Table 13 outlines the estimated cost of complying with LRET over the modelling period. That is, the product of the RPP and the estimated LGC forward price in each year of the modelling period.

17 Clean Energy Regulator, *Renewable Power Percentage*, https://cer.gov.au/schemes/renewable-energy-target/renewable-energy-target-liability-and-exemptions/renewable-power-percentage

18 DemandManager, Certificate Prices, Accessed 1 July 2025, https://demandmanager.com.au/graphs/new_prices.php

Table 13: Cost of complying with LRET ($FY26/MWh)

	FY27	FY28	FY29	FY30	FY31
Cost of complying with LRET	$3.04	$2.39	$1.73	$1.48	$0.72

Source: Frontier Economics

3.5.2 Cost of complying with the SRES

In a similar fashion to the LRET, the SRES places a legal liability on wholesale purchasers of electricity to proportionately contribute towards the costs of small scale renewable generation. Small-scale technology certificates (STCs) are created by eligible small-scale installations (such as rooftop solar PV) based on the amount of renewable electricity produced or non-renewable energy displaced by the installation.

The number of STCs to be purchased by liable entities each year is determined by the Small-scale Technology Percentage (STP), which is set each year by the Clean Energy Regulator. Liable entities can purchase STCs on the open market or through the STC Clearing House. There is a guaranteed price of $40/STC through the Clearing House, but certificates may take some time to clear, delaying payment to sellers of STCs.

In order to calculate the cost to a retailer serving WaterNSW of complying with the SRES, it is necessary to determine the STP for the retailer (which determines the number of STCs that must be purchased) and the cost of obtaining each STC.

Small-scale Technology Percentage

The STP establishes the rate of liability under the SRES and is used by liable entities to determine how many STCs they need to surrender to discharge their liability each year. The STP is published by the Clean Energy Regulator and is calculated as the percentage required to remove STCs from the STC market for the current year liability.

The STP is to be published for each compliance year by March 31 of that year. The Clean Energy Regulator must also publish a non-binding estimate of the STP for the two subsequent compliance years by March 31.

The non-binding STP for calendar years 2026 and 2027 are 11.79% and 9.28% respectively. These values are converted to financial years by taking an arithmetic average (10.54%). No non-binding STP estimate is currently available beyond calendar year 2027, so the STP has been held constant over the modelling, with the exception of FY31. The SRES scheme is scheduled to cease operation at the end of calendar year 2030. Therefore, to reflect this in the modelling we have utilised an STP of half of the 10.54% STP, such that the STP is 5.27% in FY31.

Cost of STCs

Consistent with the previous determination[19], the STC price is set equal to the STC Clearing House price of $40/certificate ($ nominal). Table 14 details these costs, on a $FY26/MWh basis.

[19] Frontier Economics, *WaterNSW's Energy Purchase Costs - Shoalhaven Transfer Scheme, A Final Report for IPART*, May 2020.

Table 14: Estimated STC cost ($FY26/MWh)

	FY27	FY28	FY29	FY30	FY31
STC cost	$39.02	$38.07	$37.14	$36.24	$35.35

Source: Frontier Economics

Cost of complying with the SRES

Table 15 outlines the estimated cost of complying with the SRES over the modelling period. That is, the product of the STP and the estimated STC price in each year of the modelling period.

Table 15: Cost of complying with the SRES ($FY26/MWh)

	FY27	FY28	FY29	FY30	FY31
Cost of complying with SRES	$4.11	$4.01	$3.91	$3.82	$1.86

Source: Frontier Economics

3.5.3 Cost of complying with the ESS

The NSW ESS places a legal liability on electricity retailers to obtain and surrender Energy Savings Certificates (ESC). The number of ESCs to be purchased and surrendered is set as a fixed percentage of electricity sales in each calendar year. Liable entities can purchase ESCs on the open market or create them through undertaking 'eligible activities'. Each certificate represents 1 MWh of energy saved.

In order to calculate the cost to a retailer serving WaterNSW of complying with the ESS, it is necessary to obtain the legislated ESS targets over the modelling period and the cost of ESCs.

Legislated ESS targets

Table 16 outlines the legislated ESS targets as updated by the NSW Government in December 2020.[20] Given the targets are in calendar years, an arithmetic average was taken to transform the targets to financial years for input into the model. These are reported in Table 17.

Table 16: Legislated ESS targets (%)

	CY26	CY27	CY28	CY29	CY30	CY31
ESS Target	11.00%	11.50%	12.00%	12.50%	13.00%	13.00%

Source: Frontier Economics

20 NSW Government, *About the Energy Savings Scheme*, n.d., https://www.energy.nsw.gov.au/nsw-plans-and-progress/regulation-and-policy/energy-security-safeguard/energy-savings-scheme/about

Table 17: Estimated financial year ESS targets (%)

	FY27	FY28	FY29	FY30	FY31
ESS Target	11.25%	11.75%	12.25%	12.75%	13.00%

Source: Frontier Economics

Cost of ESCs

We have opted to use a market price for ESCs to determine the cost of complying with the ESS. Given there is little forward trade of ESCs reported on *DemandManager*, we have used the latest spot price for ESCs as of 30 June 2025 (retrieved 1 July 2025 from *DemandManager*[21]) was $20.75 (trade date 27 June 2025). This estimated ESC price has been held constant in real terms over the modelling period at $20.75 ($FY26/MWh).

Cost of complying with the ESS

Table 18 outlines the estimated cost of complying with the ESS over the modelling period. That is, the product of the estimated financial year ESS targets and the assumed ESC price in each year of the modelling period.

Table 18: Cost of complying with the ESS ($FY26/MWh)

	FY27	FY28	FY29	FY30	FY31
Cost of complying with ESS	$2.28	$2.32	$2.36	$2.40	$2.38

Source: Frontier Economics

3.6 Market fees and ancillary services

An electricity retailer supplying electricity to WaterNSW for the Broken Hill Pipeline will also face the cost of market fees and ancillary services costs.

3.6.1 Market fees

Market fees are charged to participants in the National Energy Market (NEM) by AEMO in order to recover the cost of operating the market. The fees are based on the budgeted revenue requirements of AEMO. The market fees estimated include:

- Usage fees.
- Per National Meter Identifier (NMI) fees.

Market fees for FY26 were published in *Budget and Fees FY26.*[22] Table 19 details the market fees for FY26 as published by AEMO.

[21] Demand Manager, *Spot prices*, Accessed 23 August 2024, https://www.demandmanager.com.au/certificate-prices/

[22] AEMO, *Budget and Fees FY26*, https://aemo.com.au/-/media/files/about_aemo/energy_market_budget_and_fees/2025/aemo-final-budget-and-fees-fy26.pdf?la=en

Table 19: AEMO Market fees, FY26

Fee	Unit	Value
Usage Fees		
Market Customers (NEM Unallocated Fees, 30%) - Core Revenue Requirement	$/MWh of customer load, Nominal	$0.19038
Market Customers (NEM Allocated Fees, 70%) - Core Revenue Requirement	$/MWh of customer load, Nominal	$0.11816
5MS/GS - Market Customer Fee	$/MWh, Nominal	$0.06902
DER - Market Customer Fee	$/MWh, Nominal	$0.02284
Per NMI Fees		
Market Customers (NEM Unallocated Fees, 30%) - Core Revenue Requirement	$ Per connection point per week, Nominal	$0.05778
Market Customers (NEM Allocated Fees, 70%) - Core Revenue Requirement	$ Per connection point per week, Nominal	$0.03586
5MS/GS - Market Customer Fee	$ Per connection point per week, Nominal	$0.02095
DER - Market Customer Fee	$ Per connection point per week, Nominal	$0.00693

Source: AEMO, Budget and Fees FY26

Usage fees are reported in $/MWh, however to convert per NMI fees to an average cost (on a $/MWh basis), the charges listed were converted to annual charges (assuming a 52-week year) and divided by total electricity consumption per year (see Section 2.4).

Given there is no information available on AEMO's future costs, usage fees and per NMI fees are held constant in real terms over the modelling period. Estimated total usage fees and per NMI fees are detailed in Table 20 below.

Table 20: Estimated market fees ($FY26/MWh)

	FY27	FY28	FY29	FY30	FY31
Total usage fees	$0.40	$0.40	$0.40	$0.40	$0.40
Total NMI fees	$0.0006	$0.0006	$0.0006	$0.0006	$0.0006

Source: Frontier Economics

3.6.2 Ancillary services costs

Ancillary services are services used by AEMO to manage the power system. Ancillary services can be grouped under the following categories[23]:

- Frequency Control Ancillary Services (FCAS) are used to maintain the frequency of the electrical system.
- System Restart Ancillary Services (SRAS) are used when there has been a whole or partial system blackout and the electrical system needs to be restarted.
- Network Control Ancillary Services (NCAS) are used to control the voltage of the electrical network and control the power flow on the electricity network.

AEMO purchases NCAS and SRAS under agreements with service providers. With respect to FCAS, AEMO operates a number of separate markets for the delivery of FCAS.

Historic data on the costs incurred by AEMO in procuring ancillary services is published by AEMO online[24]. Consistent with the methodology adopted by IPART for the previous Determination, a 7 year average of ancillary service cost data published by AEMO for New South Wales region has been estimated and held constant in real terms over the modelling period as the best estimate of ancillary service costs going forward.[25]

Table 21 below details estimated ancillary service fees.

Table 21: Estimated ancillary service fees ($FY26/MWh)

	FY27	FY28	FY29	FY30	FY31
Ancillary service fees	$0.38	$0.38	$0.38	$0.38	$0.38

Source: Frontier Economics

3.7 Retail operating cost and margin

An electricity retailer supplying electricity to WaterNSW for the Broken Hill Pipeline will incur retail operating costs (ROC) and must cover its retail margin.

ROCs are costs incurred in the provision of services by a retailer to its customers, which typically include billing and revenue collection costs, call centre costs, customer information costs, corporate overheads, energy trading costs, regulatory compliance costs and marketing costs. In this instance, the customer is WaterNSW.

The retail margin includes a range of costs incurred by retailers, such as depreciation, amortisation, interest payments and tax expenses. The retail margin also represents the return to investors for retailers' exposure to systematic risks associated with providing retail electricity

[23] AEMO, *Guide to Ancillary Services in the National Electricity Market*, October 2023, https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/ancillary_services/guide-to-ancillary-services-in-the-national-electricity-market.pdf

[24] AEMO, *Ancillary Services and Frequency Performance Payments*, Accessed 1 July 2025, https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/data-nem/ancillary-services-data/ancillary-services-payments-and-recovery

[25] Data in 2025 as of 1 July 2025 was only available to 'Week 25' in 2025. Therefore, only data from 'Week 26' onward in 2018 is included to complete the 7-year time-series.

services. There is however limited publicly available information to determine appropriate ROC and retail margin allowances for larger customers.

Against this background, we have maintained the ROC allowance in real terms from the previous Determination, and utilised the same retail margin. That is, we have included:

- A ROC of $2,788.55 per year ($FY26) held constant in real terms over the modelling period. This is based on the $2,418.43 per year ($FY22) allowance from the previous Determination.
- A retail margin of 6.04% in each year (that is, retail margin as a percentage of total costs is 5.7% in each year).

3.8 Summary of forecast energy costs

Table 22, Table 23 and Table 24 respectively provide a summary of the forecast electricity costs detailed above.

Table 22 summarises the unit forecast estimate for each year of the modelling period as discussed above. Table 23 details the total annual costs by cost component, as well as total costs and total costs per MWh, as calculated utilising the forecast energy consumption results detailed in Section 2. Table 24 provides a summary of the total energy costs per annum by high-level cost component category.

Table 22: Unit forecast electricity cost by cost component ($FY26)

	Unit	FY27	FY28	FY29	FY30	FY31
Wholesale energy costs						
Wholesale energy	$FY26/MWh	$86.45	$83.80	$83.78	$83.80	$83.93
Losses	$FY26/MWh	-$0.29	-$0.28	-$0.28	-$0.28	-$0.28
UFE	$FY26/MWh	$2.25	$2.18	$2.18	$2.18	$2.19
Renewable energy policy costs						
Costs of LRET compliance	$FY26/MWh	$3.04	$2.39	$1.73	$1.48	$0.72
Costs of SRES compliance	$FY26/MWh	$4.11	$4.01	$3.91	$3.82	$1.86
Costs of ESS compliance	$FY26/MWh	$2.28	$2.32	$2.36	$2.40	$2.38
Market fees and ancillary services						
Market fees	$FY26/MWh	$0.40	$0.40	$0.40	$0.40	$0.40
Ancillary services costs	$FY26/MWh	$0.38	$0.38	$0.38	$0.38	$0.38
Network charges						
Network access	$FY26/day	$26.27	$27.01	$27.78	$27.78	$27.78
Energy Peak	$FY26/MWh	$47.70	$49.06	$50.46	$50.46	$50.46
Energy shoulder	$FY26/MWh	$38.73	$39.83	$40.97	$40.97	$40.97
Energy off peak	$FY26/MWh	$31.86	$32.77	$33.70	$33.70	$33.70
Demand peak	$FY26/kVA/M	$11.59	$11.92	$12.26	$12.26	$12.26
Demand shoulder	$FY26/kVA/M	$10.48	$10.78	$11.09	$11.09	$11.09
Demand off peak	$FY26/kVA/M	$3.14	$3.23	$3.32	$3.32	$3.32
Retail operating cost and margin						
Allowance for ROC	$FY26/annum	$2,788.55	$2,788.55	$2,788.55	$2,788.55	$2,788.55
Allowance for RM	%	6.04%	6.04%	6.04%	6.04%	6.04%

Source: Frontier Economics

Table 23: Total annual forecast electricity cost by cost component ($FY26)

	FY27	FY28	FY29	FY30	FY31
Wholesale energy costs					
Wholesale energy	$920,144.55	$892,744.70	$892,432.38	$892,754.76	$893,933.40
Losses	-$3,041.66	-$2,951.09	-$2,950.06	-$2,951.12	-$2,955.02
UFE	$23,991.18	$23,276.78	$23,268.64	$23,277.04	$23,307.77
Renewable energy policy costs					
Costs of LRET compliance	$32,269.09	$25,406.90	$18,383.93	$15,721.91	$7,667.13
Costs of SRES compliance	$43,613.35	$42,590.28	$41,543.88	$40,538.86	$19,769.64
Costs of ESS compliance	$24,159.93	$24,641.77	$25,059.17	$25,451.02	$25,310.20
Market fees and ancillary services					
Market fees	$4,253.89	$4,257.95	$4,257.17	$4,258.04	$4,256.87
Ancillary services costs	$4,030.57	$4,034.43	$4,033.69	$4,034.51	$4,033.40
Network charges					
Network access	$9,587.02	$9,887.04	$10,140.81	$10,140.81	$10,140.81
Energy Peak	$8,760.77	$8,660.71	$8,913.59	$8,968.21	$9,454.74
Energy shoulder	$104,643.63	$107,937.23	$110,422.86	$110,442.05	$110,778.24
Energy off peak	$247,202.85	$254,551.26	$262,213.99	$262,234.72	$261,534.84
Demand peak	$135,327.30	$136,755.06	$140,875.48	$141,282.39	$144,542.80
Demand shoulder	$256,127.71	$263,421.47	$270,922.93	$270,922.93	$270,922.93
Demand off peak	$76,645.29	$78,827.92	$81,072.71	$81,072.71	$81,072.71
Retail operating cost and margin					
Allowance for ROC	$2,788.55	$2,788.55	$2,788.55	$2,788.55	$2,788.55
Allowance for RM	$114,186.44	$113,360.59	$114,360.14	$114,212.62	$112,740.16
Total Costs					
Total energy costs	**$2,004,690.46**	**$1,990,191.56**	**$2,007,739.86**	**$2,005,150.02**	**$1,979,299.18**
Cost per MWh	**$188.35**	**$186.81**	**$188.49**	**$188.21**	**$185.83**

Source: Frontier Economics

Table 24: **Total annual forecast electricity cost by high level cost component ($FY26 '000)**

	FY27	FY28	FY29	FY30	FY31
Wholesale	$941.09	$913.07	$912.75	$913.08	$914.29
Renewable	$100.04	$92.64	$84.99	$81.71	$52.75
Market fees and ancillary services	$8.28	$8.29	$8.29	$8.29	$8.29
Network charges	$838.29	$860.04	$884.56	$885.06	$888.45
Retail operating cost and margin	$116.97	$116.15	$117.15	$117.00	$115.53
Total energy costs	**$2,004.69**	**$1,990.19**	**$2,007.74**	**$2,005.15**	**$1,979.30**

Source: Frontier Economics

4 True-up of energy costs

4.1 Background

To manage significant uncertainty around energy prices, WaterNSW proposed in its 2021 pricing submission that the benchmark energy allowance be subject to an end-of-period true-up for movements in the benchmark price/allowance to reflect movements in network and wholesale costs:

> *"…we are proposing to share with customers the risks associated with movements in energy costs that are beyond WaterNSW's reasonable control through an end of period true-up mechanism of movements in network and wholesale components of the benchmark electricity price"* [26]

The proposal was underpinned by the following principles:

- retain incentives to procure and use electricity as efficiently as possible;
- capture material movements in costs (increases and decreases) to ensure prices reflect costs that would be incurred by a prudent and efficient benchmark entity in providing these services over the 2022 Determination period; and
- apply simply and mechanically.

For the draft Determination, IPART, with the support of their consultants (The Centre for International Economics (CIE)), agreed – in principle – to applying an end-of-period true-up. This true-up would adjust the revenue requirement to reflect differences between wholesale and network components of benchmark energy prices that were forecast for the 2022 Determination and wholesale and network components that occurred during the regulatory period. That is, the differences between forecast and actual outcomes for these benchmark energy costs would be passed-through over the next Determination period.[27]

IPART indicated that it was …

> *"open to working with WaterNSW prior to its next submission to develop a true-up mechanism that appropriately balances energy cost risk between WaterNSW and its customers, with the intent that this mechanism would apply to energy costs over the 2022 Determination period"* [28]

and that critical to this was for WaterNSW to demonstrate that this mechanism would …

26 WaterNSW, *Pricing Proposal to the Independent Pricing and Regulatory Tribunal: Regulated prices for the Wentworth to Broen Hill Pipeline,* 30 June 2021, p.122.

27 IPART, *Maximum prices for water transportation services supplied by Water NSW for the Murray River to Broken Hill Pipeline Draft Determination*, June 2022; The CIE, *Water NSW's Broken Hill Pipeline Bulk Water Transport Volume Demand and Energy Review*, June 2022.

28 IPART, *Murray River to Broken Hill Pipeline Final Technical Report,* November 2022, p.40.

"reflect the prudent behaviour of a benchmark efficient entity, and the extent to which WaterNSW will be incentivised to efficiently manage its actual energy costs" [29]

Box 1: IPART's assessment of the proposed true-up for energy costs – 2022 Determination

"We applied cost-pass through principles in our assessment of WaterNSW's original proposed energy true-up by WaterNSW. We consider these principles support the proposal because:

- *There is a trigger event. WaterNSW proposed to pass on changes in energy costs due to movements in wholesale and network energy prices to customers at the next price review.*
- *We can assess the impact on efficient cost at the next price review.*
- *The impact on efficient cost can be material.*
- *WaterNSW cannot influence the likelihood of the trigger event or the changes in efficient cost. This is because wholesale and network energy prices are determined either by the market or other independent regulators/authorities.*
- *The true-up is symmetric and applies equally to cost increases and decreases.*
- *The true-up would support more cost-reflective prices "*

Source: IPART, Murray River to Broken Hill Pipeline Final Technical Report, *November 2022, p.38*

4.2 Approach to estimating over/under recovery over 2022 Determination period

WaterNSW is proposing a true-up of key elements of the benchmark price of electricity during the 2022 Determination period, and has asked us to provide updated estimates of a number of benchmark prices.

We understand that the approach that WaterNSW is proposing to estimating the over/under recovery over the 2022 Determination period revolves around undertaking a backward (ex post) assessment of movements in key elements of the benchmark price of electricity during the 2022 Determination period and calculating the difference in costs caused by these movements, to be recovered in 2026 Determination (while accounting for the time value of money).

The relevant steps of WaterNSW's proposed approach are as follows:

- Step 1: Determine the relevant time period.
- Step 2: Determine which costs or other assumptions are subject to true-up.
- Step 3: Collate updated assumptions, including movements in the relevant cost items.
- Step 4: Calculate cost over/under recovery for each year of period.

[29] IPART, *Murray River to Broken Hill Pipeline Final Technical Report,* November 2022, p.39.

- Step 5: Calculate total cost over/under recovery over period, including the time value of money.
- Step 6: Calculate revenue increment/ decrement to be recovered over 2026 Determination period.

Each step is discussed in turn below.

Step 1: Determine relevant time period ('application period')

The key decision here relates to whether the true-up 'application period' should be:

- The 4 years of the 2022 Determination period (2022-23 to 2025-26), or
- Should mimic the approach utilised in the Sydney Desalination Plant (SDP) Energy Adjustment Mechanism (EAM), according to which the true-up does not incorporate the last year of Determination ('review year') in the calculation of gains/losses because key input parameters are not known (such as volumes of surplus energy and sales prices). The last year of the Determination is then incorporated in the subsequent Determination.

We understand the WaterNSW's proposed approach to implementing the true-up is to replace estimates of forward prices and obligations with more recent estimates of forward prices, which means that key input parameters that are updated are available in time for incorporate all 4 years of the regulatory period. This approach avoids a large lag between costs incurred and recovered.

Step 2: Determine which costs or other assumptions are subject to true-up

The next decision is to determine which costs are subject to true-up. We understand that WaterNSW proposes that wholesale costs, network costs and environmental costs be subject to true-up, consistent with WaterNSW's proposal set out in its response to IPART's draft decision for the 2022 Determination.

We note that this option departs from IPART's 2022 Determination decision that WaterNSW had not sufficiently demonstrated that environmental costs meet the cost-pas through principles.

Our view is that there are good reasons that environmental costs should be included as part of the true-up mechanism. Specifically, we consider that a true-up of environmental costs meets IPART's cost pass-through principles for the same reason that a true-up of wholesale and network costs does:

- There is a trigger event. WaterNSW proposed to pass on changes in energy costs due to movements in forward prices of environmental certificates.
- We can assess the impact on efficient cost at the next price review. Updated forward prices of environmental certificates are available from the same sources as wee used for the 2022 Determination. Since the true-up simply updates forward prices, rather than replacing forward prices with some measure of WaterNSW's actual costs, concerns about passing-through actual costs do not arise.
- The impact on efficient cost can be material. Indeed, given that environmental costs are a material proportion of total costs (9% of total energy costs over the period of the 2022 Determination period), and prices for environmental certificates are volatile, the impact on efficient costs of changes in the prices of environmental certificates could be as material as the impact of changes in wholesale prices or network price.
- WaterNSW cannot influence the likelihood of the trigger event or the changes in efficient cost. This is because prices of environmental certificates are determined by the market.

- The true-up is symmetric and applies equally to cost increases and decreases due to changes in prices of environmental certificates.
- The true-up of environmental costs would support more cost-reflective prices.

Step 3: Collate updated assumptions including movements in the relevant cost items

The next step is to collate the inputs for each of the cost components identified to true-up the 2022 Determination benchmarks. WaterNSW have requested our assistance in providing update benchmarks for these cost components.

We have updated estimates of wholesale electricity costs for each year using updated prices for electricity contract prices reported on ASX Energy.[30] Updated NSW Base Strip futures contract prices were obtained for each financial year, with a sampling period of 40 business days immediately prior to the relevant financial year (up to and inclusive of 30 June of the previous financial year). The effect of this is simply to update an estimate of benchmark efficient wholesale costs with a more up-to-date estimate of benchmark efficient wholesale costs; the true-up does not replace an estimate of benchmark efficient wholesale costs with some measure of WaterNSW's actual wholesale energy costs.

The resulting updated contract prices are provided in Table 25.

Table 25: Updated contract prices

		FY2024	FY2025	FY2026
Updated NSW Base Strip futures contract price	$/MWh, nominal	$147.71	$129.04	$120.74

Source: ASXEnergy

We have updated network costs for each year using Essential Energy published networks tariffs for each year.[31] These out-turn tariffs have been provided to WaterNSW.

Environmental costs consist of:

- costs of purchasing Large-Scale Generation Certificates (LGCs) as part of the Large-Scale Renewable Energy Target (LRET),
- costs of purchasing Small-scale Technology Certificate's (STCs) as part of the Small-scale Renewable Energy Scheme (SRES), and
- costs of purchasing Energy Savings Certificates (ESCs) under the NSW Energy Savings Scheme (ESS).

We have updated LRET costs using up-to-date information on the annual renewable power percentage (based on Clean Energy Regulator published data)[32] and updated LGC futures contract prices (published by Demand Manager).[33] LGC futures contract prices were obtained for

30 ASX Energy, *The Australian Power Market*, https://www.asxenergy.com.au/

31 BHND3AO tariff class. https://www.essentialenergy.com.au/our-network/network-pricing-and-regulatory-reporting/network-pricing

32 Clean Energy Regulator, *Renewable power percentage*, https://cer.gov.au/schemes/renewable-energy-target/renewable-energy-target-liability-and-exemptions/renewable-power-percentage

33 DemandManager, Certificate Prices, https://demandmanager.com.au/graphs/new_prices.php

each financial year with a sampling period of 40 business days immediately prior to the relevant financial year (up to and inclusive of 30 June of the previous financial year).

The resulting updated certificate prices and RPPs are provided in Table 26.

Table 26: Updated LGC price and RPPs

		FY2024	FY2025	FY2026
Updated LGC price	$/certificate, nominal	$56.78	$47.51	$19.17
Updated RPP	%	18.96%	18.48%	17.91%

Source: Demand Manager and Clean Energy Regulator

We have updated SRES costs using up-to-date information on the Small-scale technology percentage data (based on Clean Energy Regulator data).[34] Since the price of STCs is based on the clearing house price, which has not changed, this price does not need to be updated.

The resulting updated STPs are provided in Table 27.

Table 27: Updated STPs

		FY2024	FY2025	FY2026
Updated STP	%	17.14%	18.70%	12.84%

Source: Clean Energy Regulator

We have updated ESS costs using the final traded ESC spot price before the beginning of a relevant financial year. Since the quantity of ESCs required to be purchased is legislated and has not changed, this percentage does not need to be updated.

The resulting updated ESC prices are provided in Table 28.

Table 28: Updated ESC price

		FY2024	FY2025	FY2026
Updated ESC price	$/certificate, nominal	$27.33	$18.40	$20.43

Source: Demand Manager

As with wholesale energy costs, the effect of this approach to renewable costs is simply to update an estimate of benchmark efficient renewable costs with a more up-to-date estimate of

34 Clean Energy Regulator, *Small-scale technology percentage*, https://cer.gov.au/schemes/renewable-energy-target/renewable-energy-target-liability-and-exemptions/small-scale-technology-percentage

benchmark efficient renewable costs; the true-up does not replace an estimate of benchmark efficient renewable costs with some measure of WaterNSW's actual renewable costs.

Step 4: Calculate cost over/under-recovery for each year of period

We understand that WaterNSW's approach to calculating the over/under recovery of costs for each year of the period for the wholesale, network and environmental cost components is as laid out in Figure 1. We have provided updated benchmarks (for prices and, for renewable schemes, for obligations) that are suitable for use with this approach.

We note that electricity losses and the retail margin are each defined as a percentage of relevant costs. The implication of this is that updating wholesale electricity costs, network costs and renewable electricity costs also lead to flow-on adjustments to the retail margin and losses, even without an update to the loss factor or the retail margin used for the 2022 Determination.

Figure 1: Approach to calculating cost over/under recovery for each cost component

For each financial year respectively:				
Wholesale (difference p.a.)	=	\$FY22/MWh IPART benchmark x Annual consumption in MWh (from decision)	−	\$FY22/MWh Updated benchmark x Annual consumption in MWh (from decision)
Network costs (difference p.a.)	=	2020-21 network tariffs (held constant in real terms) x Energy consumption/demand benchmarks (from decision)	−	Updated published tariffs for each FY x Energy consumption/demand benchmarks (from decision)
Environmental costs (difference p.a.)	=	LRET: \$FY22/MWh IPART benchmark x FY23 RPP x consumption benchmark from decision SRES: \$FY22/MWh benchmark x FY23 STP % x consumption benchmark from decision ESS: \$FY22/MWh IPART benchmark x consumption benchmark from decision	−	LRET: \$FY22/MWh Updated benchmark x Updated RPPs x consumption benchmark from decision SRES: \$FY22/MWh benchmark x Updated STP %'s x consumption benchmark from decision ESS: \$FY22/MWh Updated benchmarks x consumption benchmark from decision

Source: Frontier Economics

Step 5: Calculate total cost over/under recovery over period, including the time value of money

The recovery or return of costs in the next regulatory period requires that the true-up amounts in each year of the 2022 Determination are adjusted to account for both the time value of money and inflation (due to the timing difference between when the difference in costs occurs and when the difference in costs is reflected in prices to customers). We understand that WaterNSW will apply these adjustments to differences in costs calculated using the nominal values we have provided.

Step 6: Calculate revenue increment/decrement to be recovered over 2026 Determination period

The recovery of return of costs in the next regulatory period requires a calculation of the amount to be recovered in each year of the next regulatory period. We understand that WaterNSW proposes to smooth the over/under recovery of costs over each year of the next regulatory period. In order to put neutral in present value terms, this approach requires that annual amounts of revenue increment/decrement are adjusted for inflation and the time value of money during the next regulatory period.

4.3 Proposed true-up mechanism for 2026 Determination and recovery in following period

WaterNSW has also asked for our view on the true-up mechanism to apply for the 2026 Determination.

Our view is that the true-up proposed by WaterNSW for the 2022 Determination, which was supported by IPART's consultants, the CIE, and accepted in principle by IPART, remains relevant for the 2026 Determination.

Importantly, as we discussed in Section 4.2, our view is that there is good reason to also include environmental costs in the true-up mechanism, as was proposed by WaterNSW in its response to IPART's draft decision for the 2022 Determination. Our view is that doing so is consistent with cost-pass through principles.

IPART's approach to the true-up for the 2022 Determination was to confirm that it was "open to working with WaterNSW prior to its next submission to develop a true-up mechanism that appropriately balances energy cost risk between WaterNSW and its customers".[35] IPART did not agree to a defined approach to undertaking the true-up mechanism to cover the period of the 2022 Determination.

WaterNSW noted in its revised proposal (draft decision response) that a clear methodology was required from IPART to identify risks that needed to be managed. CIE agreed with WaterNSW's draft decision response that it would be better able to manage the risk associated with uncertain energy costs if greater clarity was provided as to IPART's intentions. In its 2022 Final Report, IPART invited WaterNSW to provide further justification for its proposed energy true-up mechanism.

In our view, there is benefit to including a defined approach to the calculation of the true-up mechanism in the 2026 Determination. One of the benefits of undertaking a true-up is that it results in cost-reflective prices. Cost-reflective prices, in turn, provide incentives for market participants – both producers and consumers – to make efficient decisions. However, market participants can make efficient decisions only if they know what prices they will be facing and are able to respond accordingly. Including a defined approach to the calculation of the true-up mechanism provides market participants with greater certainty about the prices that will prevail and provides market participants with the opportunity to make efficient decisions in response to these prices.

[35] IPART, *Murray River to Broken Hill Pipeline Final Technical Report,* November 2022, p.40.

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