



Annual price-setting compliance statement

**For the second assessment period
(1 April 2026 - 31 March 2027)**

For prices applying from 1 April 2026

Issued 20 February 2026

Contents

- 1. Purpose of this document 3
- 2. Date of completion 3
- 3. Directors’ certificate 3
- 4. Demonstration of compliance 4
- 5. Calculating forecast allowable revenue 5
 - 5.1 Forecast net allowable revenue 5
 - 5.2 Forecast pass-through and recoverable costs..... 6
 - 5.3 Wash-up drawdown amounts 8
- 6. Calculating forecast revenue from prices..... 9
 - Appendix A Schedule of forecast chargeable quantities..... 13
 - Appendix B Calculation of forecast revenue from prices 17

1. Purpose of this document

Electricity Ashburton Limited trading as EA Networks provides electricity distribution services predominantly between the Rangitata and Rakaia rivers, an area that covers 3500 km². We receive electricity from Transpower's national grid and distribute this electricity to more than 21,000 homes and businesses that are connected to our network.

We charge electricity retailers on a wholesale basis for this delivery service. Retailers, in turn, include this cost in their retail electricity prices - our delivery charges, including Transpower's charges to us, typically amount to 27% of a household's electricity bill.

As a natural monopoly service provider, we are subject to government regulation under the Commerce Act 1986. Pursuant to the requirements of this Act, the Commerce Commission has set a regulatory framework that includes information disclosure regulations, default price-quality paths (DPP) and the option for distribution businesses to apply for a customised price-quality path (CPP).

EA Networks is subject to the Electricity Distribution Services Default Price-Quality Path Determination 2025 (the Determination) set by the Commerce Commission, and this applies to the five-year regulatory period from 1 April 2025 to 31 March 2030.

The Determination requires us to issue an "annual price-setting compliance statement" prior to the start of each assessment period, as well as an "annual compliance statement" within 5 months after the end of each assessment period to demonstrate compliance, or otherwise, within the requirements of the Determination.

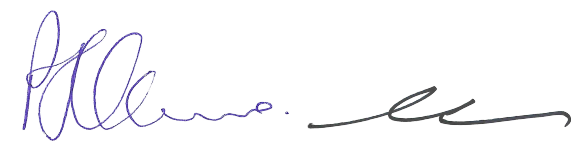
This annual price-setting compliance statement covers the information requirements detailed in clause 11 of the Determination in relation to prices applying from 1 April 2026 to 31 March 2027, the second assessment period in the five-year regulatory period.

2. Date of completion

This statement was prepared on and uses information and data known as at 22 December 2025 when pricing was determined.

3. Directors' certificate

We, Paul Jason Munro and Andrew David Barlass, being directors of Electricity Ashburton Limited trading as EA Networks certify that, having made all reasonable enquiry, to the best of our knowledge and belief, the attached annual price-setting compliance statement of EA Networks, and related information, prepared for the purpose of the Electricity Distribution Services Default Price-Quality Path Determination 2025 has been prepared in accordance with all the relevant requirements, and all forecasts used in the calculations for forecast revenue from prices and forecast allowable revenue are reasonable.



Paul Jason Munro

Andrew David Barlass

20 February 2026

4. Demonstration of compliance

Clause 8.3 of the Determination requires that forecast revenue from prices does not exceed forecast allowable revenue for that assessment period.

Clause 8.4 of the Determination requires that, for the second to fifth assessment periods, forecast revenue from prices, less forecast pass-through costs, less revenue forecast to be received under any large connection contract, does not exceed the revenue smoothing limit.

EA Networks complies with the price path for the assessment period 1 April 2026 to 31 March 2027, as demonstrated below:

Demonstration that forecast revenue from prices does not exceed forecast allowable revenue for the assessment period	
	\$000
Forecast allowable revenue	71,509
Forecast revenue from prices	67,392
<u>Compliance test result:</u>	
Comply because forecast revenue from prices is less than forecast allowable revenue.	

Demonstration that forecast revenue from prices, less forecast pass-through costs, less forecast revenue under large connection contracts, does not exceed the revenue smoothing limit	
	\$000
Forecast revenue from prices	67,392
Less: Forecast pass-through costs	(15,837)
Less: Large connection contract revenue	(0)
	51,555
Revenue smoothing limit – second assessment period	60,469
<u>Compliance test result:</u>	
Comply because forecast revenue from prices minus pass-through costs minus large connection contract revenue is less than the revenue smoothing limit.	

Note that all prices, charges, costs and revenue figures in this document are stated exclusive of GST.

The remainder of this document contains more details about the costs and assumptions that underpin these forecasts. Section 5, details how *forecast allowable revenue* was calculated. Section 6, Appendix A and Appendix B provide information about *forecast revenue from prices*.

EA Networks complies with the price path as set out in clause 8.3 and 8.4 of the Determination.

5. Calculating forecast allowable revenue

The 2026/27 assessment period is the second annual assessment period under the 2025 Determination. EA Networks forecast allowable revenue for each annual assessment period is determined in accordance with the following:

$$\begin{aligned} \text{Forecast allowable revenue} = & \text{Forecast net allowable revenue} \\ & + \text{Revenue forecast to be received under all large connection contracts} \\ & + \text{Forecast pass-through costs} \\ & + \text{Forecast recoverable costs} \end{aligned}$$

The calculation of EA Networks forecast allowable revenue for the 2026/27 assessment period is provided in the table below.

EA Networks forecast allowable revenue 2026/27	
Calculation Components	Amount (\$000)
Forecast net allowable revenue	50,088
Revenue forecast to be received under all large connection contracts	0
Forecast pass-through costs	15,837
Forecast recoverable costs	5,584
Forecast allowable revenue	71,509

The four components of forecast allowable revenue for the 2026/27 assessment period are described in more detail below.

5.1 Forecast net allowable revenue

Forecast net allowable revenue for the second to fifth assessment period is calculated in accordance with the formula outlined in Schedule 1.3 of the Determination.

Forecast net allowable for the second to fifth assessment period is calculated as:

Forecast net allowable revenue for the first assessment period x (1 + change in forecast CPI) x (1 – annual rate of change) ^(current assessment period number – 1)

‘Forecast net allowable revenue for the first assessment period’ represents starting prices as specified in Schedule 1.1 of the Determination. For Electricity Ashburton this amount is \$44,281k.

‘Change in forecast CPI’ is calculated as the (sum of each quarter forecast CPI in the current assessment period) / (sum of each quarter forecast CPI in the first assessment period) – 1

The CPI figures for the second assessment period is calculated as (1335 + 1347 + 1351 + 1358) / (1306 + 1319 + 1322 + 1329) – 1 which calculates as 2.18%.

‘Annual rate of change’ is provided in Schedule 1.2 of the determination which for Electricity Ashburton Limited is -10.7%.

‘Current assessment period number’ for the second assessment period is 2.

Applying the above information to the required formula gives a forecast net allowable revenue amount of:

$$44,281 \times (1 + 2.18\%) \times (1 - 10.7\%)^{(2-1)} = \$50,088k.$$

5.2 Forecast pass-through and recoverable costs

Pass-through and recoverable costs have the meanings given in the input methodology.

This represents the sum of all forecast pass-through and recoverable costs. Schedule 1.4 of the Determination requires that the forecast must be demonstrably reasonable.

The following table details pass-through and recoverable costs which relate to EA Networks and the associated forecasting method.

	Forecast method	IM Reference	(\$000)
Forecast pass-through costs			
Levies and Rates			
Commerce Commission levies	Historical charges with CPI adjustment	3.1.2(2)(b)	133
Electricity Authority levies	Historical charges with CPI adjustment	3.1.2(2)(b)	160
Utilities Disputes levies	Historical charges with CPI adjustment	3.1.2(2)(b)	16
Council rates	Historical charges with CPI adjustment	3.1.2(2)(a)	308
Transpower charges			
Connection	Notified by supplier	3.1.2(2)(c)	385
Residual	Notified by supplier	3.1.2(2)(c)	12,894
Benefit	Notified by supplier	3.1.2(2)(c)	1,876
Transitional cap	Notified by supplier	3.1.2(2)(c)	8
New investment	Notified by supplier	3.1.2(2)(d)	57
Total forecast pass-through costs			15,837
Forecast recoverable costs			
Incentives			
IRIS incentive adjustment	Commerce Commission spreadsheet	3.1.3(1)(a)	(463)
Quality incentives	Calculated in accordance with the Determination schedule 4. Refer to EA Networks annual compliance statement for the year ended 31 March 2025 for further details (Reliable external information).	3.1.3(1)(k)	(55)
Other recoverable cost			
Wash-up drawdown amount	Calculated in accordance with IM reference 3.1.4(5) (reliable external information).	3.1.3(1)(n)	6,046
Fire and Emergency New Zealand levy	Historical charges with CPI adjustment	3.1.3(1)(o)	56
Total forecast recoverable costs			5,584
Forecast pass-through and recoverable costs			21,421

Our forecasting approaches

We use the following three approaches to forecast recoverable and pass-through costs:

- Notified by supplier
- External information
- Historical costs with CPI adjustments

Notified by supplier

When the supplier has advised us of its cost for the year, we use that amount as the forecast plus any additional amounts reasonably expected. The specific calculation for new solar farms uses transmission charges on existing solar farms, adjusted pro-rata based on connection size and timing of connection.

External information

When the pass-through cost is an incentive or wash-up item and the associated cost has not been formally notified to us, we have based our forecast on the output of an external supplier (Commission) excel workbook.

Historical charges with CPI adjustments

When the above two methods do not result in a demonstrably reasonable forecast, we use historical costs available as of 30 November 2025 adjusted by CPI.

Our internal budgeting process uses CPI forecast as a predictor of likely future costs in the absence of better information. This means our approach to determining the likely pass-through costs is consistent with our financial modelling on which we base business decisions.

We have based our CPI adjustment on the November 2025 RBNZ Monetary Policy Statement.

The forecasting approach is consistent with the prior periods approach to estimating pass-through and recoverable costs.

5.3 Wash-up drawdown amounts

The calculation of the wash-up drawdown amount is outlined in Schedule 1.6 and 1.7 of the determination and Section 3.1.4(5) of the input methodology. For the second assessment period the maximum wash-up drawdown allowed will be drawn down.

$$(\text{wash-up account balance for the disclosure year two years prior} \times (1 + \text{the cost of capital estimate}) \times (1 + \text{the cost of capital estimate}) - \text{wash-up drawdown amount for the disclosure year one-year prior} \times (1 + \text{midpoint estimate of post-tax WACC}))$$

The wash-up account balance for the disclosure year two years prior is based off the wash-up amounts within Electricity Ashburton Limited's annual compliance statements for the year ended 31 March 2025 (\$5,416k) + year ended 31 March 2024 (\$6,485k adjusted by the 67th percentile estimate of post-tax WACC).

The 67th percentile estimate of post-tax WACC under the previous regulatory period was set by the Commerce Commission at 4.23%.

The cost of capital estimate is calculated in accordance with 3.1.4(12)(b) of the input methodology (wash-up amounts) amendment determination 2024. For the first assessment period this is calculated as (67th percentile estimate of post-tax WACC x 0.41 weighting) + (mid-point estimate of post-tax WACC set by the Commerce Commission of 6.02% x 0.59 weighting) resulting in 5.29%. For the second to fifth assessment period the cost of capital estimate is the midpoint estimate of WACC of 6.02%.

The wash-up drawdown amount for the disclosure year one year prior is calculated as the wash-up amount calculated in the annual compliance statement for the year ended 31 March 2024 x (1 + 67th percentile estimate of post-tax WACC)².

Applying the above information to the required formula gives a wash-up drawdown amount of
$$(\$12,175\text{k} \times (1 + 5.29\%) \times (1 + 6.02\%) - \$7,116\text{k} \times (1 + 6.02\%)) = \$6,046\text{k}$$

6. Calculating forecast revenue from prices

EA Networks' forecast revenue from prices is equal to prices for the assessment period multiplied by the forecast quantities they apply to. The Determination requires that these forecast quantities are demonstrably reasonable.

Our forecasting approach is driven by trends in observed chargeable quantities from prior years. As the current year is not complete, we extract the actual quantities for the first part of the year, prepare an updated estimate for the remaining months and use this to inform our forecasts for the following year.

We consider the appropriate trend for each chargeable quantity individually. Our default approach is to apply a 4-year linear trend (using actual quantities for FY23 to FY25 together with an updated estimate for FY26 to forecast a quantity for FY27). We have used an alternative approach for specific quantities where we have information that supports an alternative approach, and the basis of these alternatives is noted in Appendix A.

This year we are applying significant structural changes to our prices that introduce new chargeable quantities. Forecasts for these quantities are based on prior chargeable quantities that are split or combined based on an assessment of how we intend to migrate supplies to the new basis, and how we expect customers might react to the new basis. The forecasts also consider minor structural changes that we applied in prior years.

Structural changes result in step changes in the progression of chargeable quantities, and this 'external' influence is indicated in our charts with directional arrows.

In some situations, structural changes mean that we have a shorter history of values. In these circumstances we use the most recent results to inform our forecast.

Appendix A shows each forecast together with prior year results and the method used for each forecast.

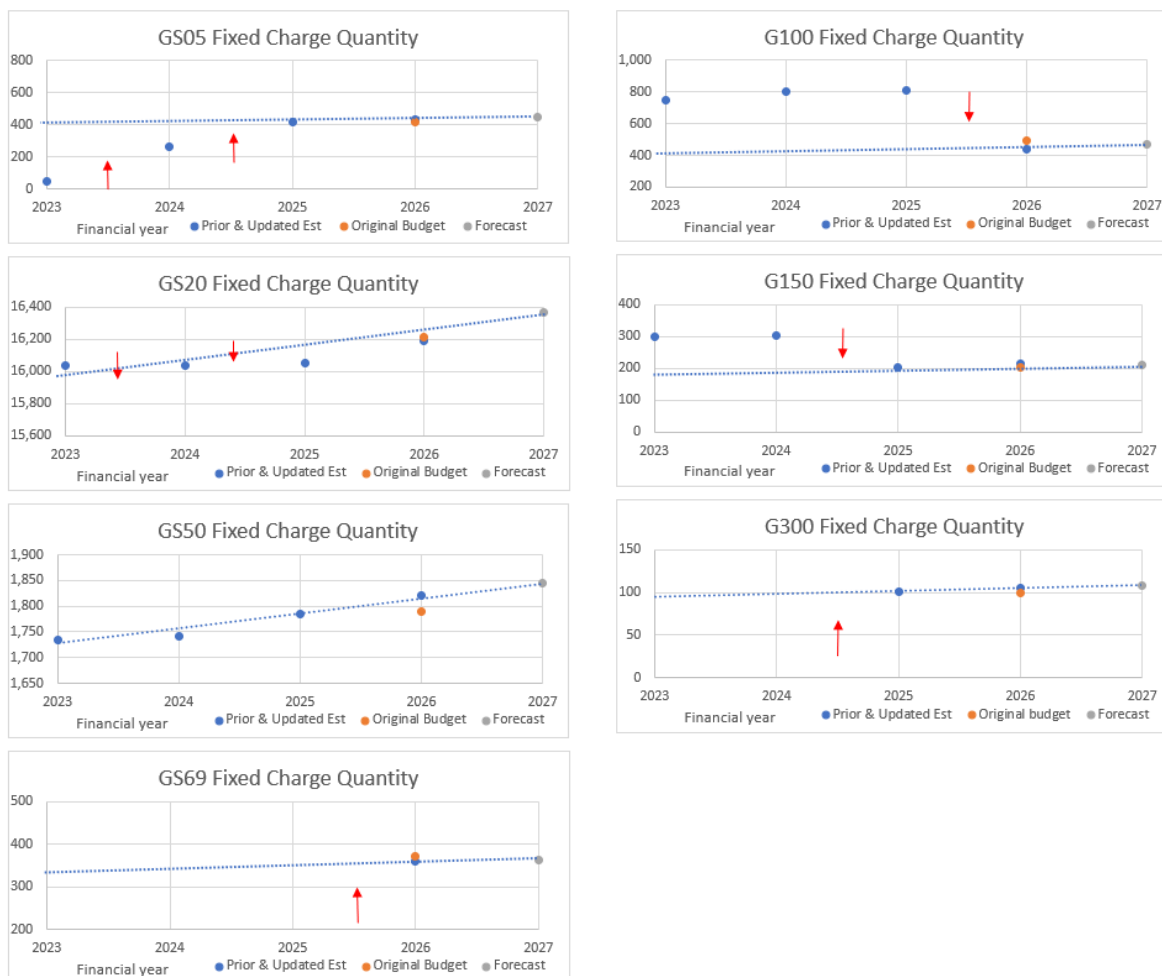
Commentary on the categories that represent the main revenue contributors follows.

General supply fixed charges

We observe a largely consistent (linear) growth in our connections, by number. The exceptions are:

- In FY24 we opened our 8kVA category to metered connections (previously it was restricted to unmetered) and this has seen a shift of several hundred customers from the 20 kVA category over several years. With rising fixed charges, we expect more customers to 'right-size' their supplies including shifting to this category. For the current year, we have observed an above-forecast result. To take account of our new settings, the forecast is based on a 2-year linear trend.
- For the 20kVA category we have added back the ICPs that shifted to the 8 kVA category for the purpose of establishing our 4-year linear trend, and have then deducted off the number that we forecast to be in the 8 kVA category.
- In FY26 we are splitting the 100 kVA category into two – a 100 kVA category and a smaller 69 kVA category. For the 100 kVA category we prepared our linear trend on the total for the two categories, but then deducted off the number categorised to the 69 kVA category.
- For the 69 kVA category we only have a single observation (an updated estimate for FY26). We have forecast this will move in proportion to our 20 kVA category, as an indicator of underlying growth in customer numbers.
- In FY25 we split the 150 kVA category into two – a 150 kVA category and a larger 300 kVA category. For the 150 kVA category we prepared our linear trend on the total for the two categories, but then deducted off the number categorised to the 300 kVA category.
- For the 300 kVA category, current results are above-forecast. With a limited history, we have moved to using a 2-year linear trend to capture the upward trajectory (rather than assuming a static quantity).

These changes affect the history of connection count, and the external impacts are shown with arrows in the charts below.



General supply volume charges

Volumes are forecast for each general connection subcategory separately. As prices are the same, the charts below show the total across all subcategories to which they apply.

Volume components are significantly affected by weather conditions. In particular, residential heating is greater during cold winters, and the smaller irrigation connections in this category contribute a lot more during dry summers.

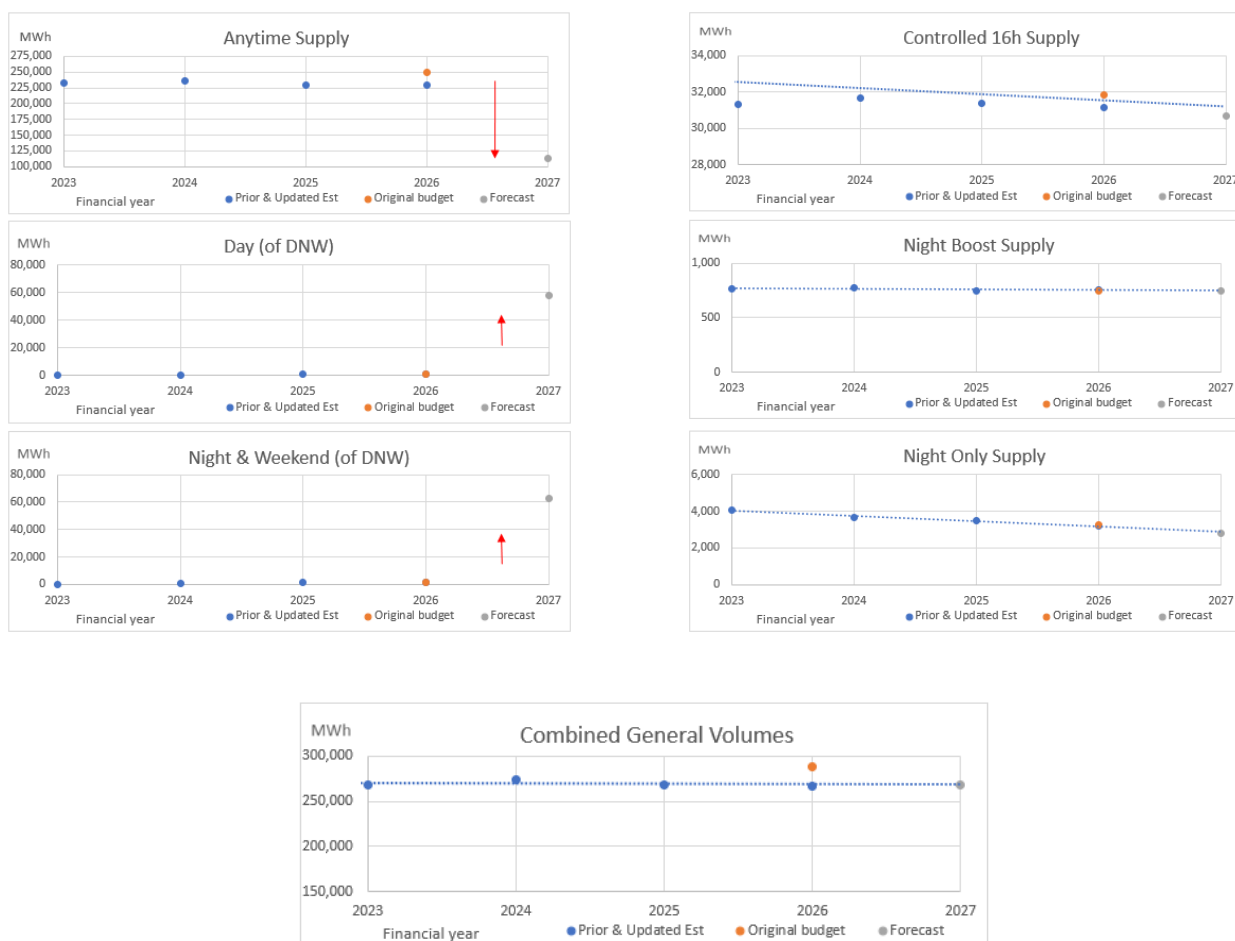
For FY27, we are required to price the majority of our previous “anytime” metered volumes on a time-varying basis. For us this means using our day, night & weekend pricing approach. For the affected categories, we have estimated the quantum of volume that will shift across based on an assessment of supplies with qualifying meters, and we have further assessed the split between the day volume and the night & weekend volume based on the residual profile from the energy market reconciliation for the Ashburton area.

We are also required to include credits for export during times where, on average and in the long term, the export addresses peak demand that would otherwise contribute to the need for capacity reinforcement. We have projected that the increasing trend of total export will continue, then we have used a representative solar customer output to profile that export between the defined peak periods and off peak periods.

For our controlled supplies, we have adopted the standard 4-year trend approach, with some options increasing and others reducing.

This year we have observed that our Anytime volume results are falling around 7% below our forecasts for the year-to-date. This is captured in our updated estimate, and has informed our FY27 projection. We are undertaking further analysis of the cause of this outcome, but there is no indication that the trend will reverse, and we are now projecting a gradual decline in chargeable volumes.

Note that red arrows show the impact of categorisation changes. Given the impact of structural changes, the final chart below shows the combined movement of all chargeable volume components combined.

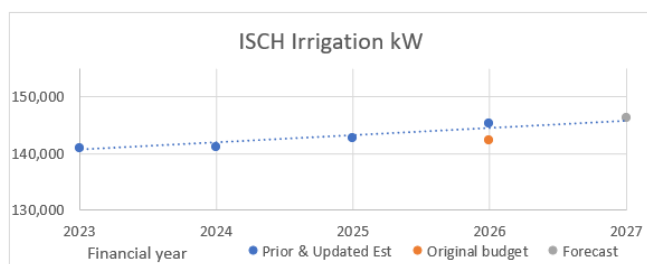


Irrigation chargeable kW

Irrigation is significantly constrained by Environment Canterbury resource consenting restrictions, and we expect any growth to be offset by the relinquishing of irrigation plant that is currently being maintained as a back-up for the piped irrigation schemes that have been developed over the last few years.

The capacity charge is based on installed equipment, and recent increases are a reflection of our new and now ongoing validation against metered peak loading levels enabled through smart metering data provided by retailers. This picks up situations where equipment may have been recorded incorrectly or changed and we take corrective action to update our basis for charging.

Picking up both of these aspects, for FY27 we have forecast the chargeable kW using a 4-year linear trend.



In FY26 we introduced a separate irrigation recovery charge category. This carries a higher price and will apply to customers that choose to seasonally disconnect. We have assessed the quantities that will apply based on the observed rate of seasonal disconnection in FY24.

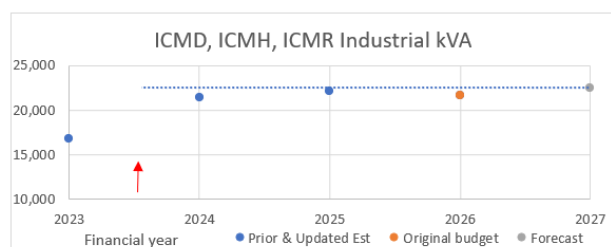
Industrial category

In FY24 we moved to a booked capacity charging approach, where we charge based on the physical capacity available for each connection. The previous approach was to charge based on the peak demand reached each month.

With this change we only have a limited period of quantities to base our projection on. Over this initial period we are seeing a number of adjustments as customers respond to the new charging approach and “right size” their capacity. Our best estimate is that the current levels reached will remain in place.

We also recently introduced a separate component within the industrial category to cater for high voltage supplies where we do not provide the final transformer (ICMH). These are unusual and we do not expect a high uptake – we have set the forecast chargeable quantity to match the chargeable quantity for the two connections in this situation.

Finally, we have introduced an industrial recovery charge category (ICMR - along the lines used for irrigation). This carries a higher price to recover the annual revenue amount, and will apply to customers that choose to seasonally disconnect. We expect this charge to deter this “arbitrage” incentive, and therefore we expect the chargeable quantities to remain at nil.



Other categories

The remaining categories are connection specific where chargeable quantities tend to remain static. These have been forecast to be in-line with current quantities, as no significant changes are anticipated.

Appendix A Schedule of forecast chargeable quantities

Category / Charge component			FY2022	FY2023	FY2024	FY2025	FY2026		FY2027	Units	Forecast method
	Code	Note	(actual)	(actual)	(actual)	(actual)	update estimate	(original budget)	(forecast)		
General 8kVA											
Fixed	GS05	Opened to metered supplies in FY24	49.1	48.8	261.2	415.9	430.6	416.0	445.3	Connections	2 year linear trend using updated estimate for FY26 (limited history)
Anytime supply	GDEF	Renamed GUEN to GDEF FY27	9.5	50.9	506.0	892.3	886.6	1,091.5	176.6	MWh	2 year linear trend less assessed reassignment to day/night & weekend
Controlled 16h supply	GCOP		-	-	131.6	217.6	207.2	232.1	196.9	MWh	2 year linear trend using updated estimate for FY26 (limited history)
Night boost supply	G10N		-	-	2.1	2.7	0.01	4.90	0.01	MWh	Set to updated estimate for FY26 - only 2 ICPs left consuming on this option
Night only supply	GNEN		-	-	6.5	10.8	13.0	13.8	15.3	MWh	2 year linear trend using updated estimate for FY26 (limited history)
Day (of DNW)	GDAY	New in FY24			10.0	24.2	19.6	30.1	1,219.0	MWh	2 year linear trend, plus assessed reassignment of anytime volumes
Night & Weekend (of DNW)	GNWE	New in FY24			11.5	30.5	20.3	38.3	376.2	MWh	2 year linear trend, plus assessed reassignment of anytime volumes
Anytime injection	GEDG		-	-	7.0	7.9	6.3	4.8	-	MWh	Ended FY26 (changed to GINO, GIOR, GIPR, GIPU)
Anytime injection	GINO	New in FY27							2.4	MWh	Prior export divided up based on installed generation capacity and observed solar export profile
Off-peak injection (ExportRL)	GIOR	New in FY27							2.7	MWh	
Peak injection (ExportRL)	GIPR	New in FY27							0.3	MWh	
Off-peak injection (ExportUA)	GIOW	New in FY27							1.0	MWh	
Peak injection (ExportUA)	GIPU	New in FY27							0.0	MWh	
General 20kVA											
Fixed	GS20		15,813.9	16,034.0	16,034.3	16,051.4	16,189.7	16,211.2	16,367.3	Connections	4 year linear trend using updated estimate for FY26 (adjusted for recategorisation to GS05)
Anytime supply	GDEF	Renamed GUEN to GDEF FY27	94,010.8	95,753.4	95,597.7	94,444.8	92,925.7	99,429.5	3,468.7	MWh	4 year linear trend, adjusted for recategorisation to GS05, and less assessed reassignment to day/night & weekend
Controlled 16h supply	GCOP		29,027.4	28,629.8	28,905.2	28,788.0	28,626.1	29,337.3	28,824.4	MWh	4 year linear trend, adjusted for recategorisation to GS05
Night boost supply	G10N		690.0	665.1	674.1	655.8	618.0	645.7	614.7	MWh	4 year linear trend, adjusted for recategorisation to GS05
Night only supply	GNEN		3,821.7	3,548.4	3,197.6	3,017.5	2,753.0	2,786.3	2,490.6	MWh	4 year linear trend, adjusted for recategorisation to GS05
Day (of DNW)	GDAY	New in FY24			351.8	881.4	1,093.0	1,027.7	44,481.1	MWh	2 year linear trend, plus assessed reassignment of anytime volumes
Night & Weekend (of DNW)	GNWE	New in FY24			421.8	1,269.7	1,632.3	1,488.8	48,751.7	MWh	2 year linear trend, plus assessed reassignment of anytime volumes
Anytime injection	GEDG		527.1	890.0	1,103.8	1,547.6	2,289.7	1,836.6	-	MWh	Ended FY26 (changed to GINO, GIOR, GIPR, GIPU)
Anytime injection	GINO	New in FY27							53.7	MWh	Prior export divided up based on installed generation capacity and observed solar export profile
Off-peak injection (ExportRL)	GIOR	New in FY27							1,024.5	MWh	
Peak injection (ExportRL)	GIPR	New in FY27							106.3	MWh	
Off-peak injection (ExportUA)	GIOW	New in FY27							1,419.7	MWh	
Peak injection (ExportUA)	GIPU	New in FY27							14.3	MWh	
Unmetered streetlighting	MCSL	Closed (no additions)	-	9.0	9.0	9.0	9.0	9.0	9.0	Fixtures	Forecast to remain at current level
Unmetered floodlighting	MCRF	Closed (no additions)	2.0	2.0	2.0	2.0	2.0	2.0	2.0	Fixtures	Forecast to remain at current level
Unmetered verandah lighting	MCRU	Closed (no additions)	10.7	10.9	10.0	10.0	10.0	10.2	10.0	Fixtures	Forecast to remain at current level
General 50kVA											
Fixed	GS50		1,700.6	1,735.4	1,741.5	1,785.3	1,820.7	1,789.3	1,845.7	Connections	4 year linear trend. Increase driven by recategorisation work expected to continue
Anytime supply	GDEF	Renamed GUEN to GDEF FY27	30,632.0	29,175.6	27,621.0	26,868.7	27,730.9	26,666.6	1,600.7	MWh	4 year linear trend, less assessed reassignment to day/night & weekend
Controlled 16h supply	GCOP		1,994.9	1,995.7	1,894.7	1,800.7	1,768.8	1,733.8	1,671.3	MWh	4 year linear trend using updated estimate for FY26
Night boost supply	G10N		94.5	97.7	95.0	87.6	137.7	94.1	132.7	MWh	4 year linear trend using updated estimate for FY26
Night only supply	GNEN		404.6	379.0	310.5	340.1	299.7	329.3	280.3	MWh	4 year linear trend using updated estimate for FY26
Day (of DNW)	GDAY	New in FY24			173.4	210.4	231.4	174.4	12,243.6	MWh	2 year linear trend, plus assessed reassignment of anytime volumes
Night & Weekend (of DNW)	GNWE	New in FY24			80.7	141.6	173.9	146.9	13,191.9	MWh	2 year linear trend, plus assessed reassignment of anytime volumes
Anytime injection	GEDG		132.3	211.0	318.3	424.0	539.1	572.8	-	MWh	Ended FY26 (changed to GINO, GIOR, GIPR, GIPU)
Anytime injection	GINO	New in FY27							122.1	MWh	Prior export divided up based on installed generation capacity and observed solar export profile
Off-peak injection (ExportRL)	GIOR	New in FY27							339.6	MWh	
Peak injection (ExportRL)	GIPR	New in FY27							35.2	MWh	
Off-peak injection (ExportUA)	GIOW	New in FY27							147.1	MWh	
Peak injection (ExportUA)	GIPU	New in FY27							1.5	MWh	
Unmetered streetlighting	MCSL	Closed (no additions)	-	-	-	-	-	-	-	Fixtures	Forecast to remain at current level
Unmetered floodlighting	MCRF	Closed (no additions)	-	-	-	-	-	-	-	Fixtures	Forecast to remain at current level
Unmetered verandah lighting	MCRU	Closed (no additions)	1.0	1.0	1.0	1.0	1.0	1.0	1.0	Fixtures	Forecast to remain at current level

Category / Charge component		Note	FY2022 (actual)	FY2023 (actual)	FY2024 (actual)	FY2025 (actual)	FY2026 update estimate(original budget)	FY2027 (forecast)	Units	Forecast method	
		Code									
General 69kVA											
Fixed	GS69	New in FY26				-	359.8	371.0	363.8	Connections	Adjusted with GS20 growth (no history or other basis for assessment)
Anytime supply	GUEN					-	19,074.9	19,128.8	20,090.2	MWh	4 year trend (GS69 and G100 combined), factored for GS69 based on FY26 estimate
Controlled 16h supply	GCOP	Discontinued 31/3/2026				-	198.7	218.0	-	MWh	Discontinued 31/3/2026
Night boost supply	G10N	Discontinued 31/3/2026				-	3.4	-	-	MWh	Discontinued 31/3/2026
Night only supply	GNEN	Discontinued 31/3/2026				-	70.1	108.1	-	MWh	Discontinued 31/3/2026
Anytime injection	GEDG					-	170.4	68.3	208.5	MWh	4 year trend (GS69 and G100 combined), factored for GS69 based on FY26 estimate
Unmetered streetlighting	MCSL	Closed (no additions)				-	-	-	-	Fixtures	Forecast to remain at current level
Unmetered floodlighting	MCRF	Closed (no additions)				-	-	-	-	Fixtures	Forecast to remain at current level
Unmetered verandah lighting	MCRU	Closed (no additions)				-	1.0	-	-	Fixtures	Forecast to remain at current level
General 100kVA											
Fixed	G100		713.4	745.5	798.6	813.3	438.7	490.4	468.6	Connections	4 year linear trend less recategorisation to GS69
Anytime supply	GUEN		57,031.3	60,573.4	65,823.8	65,622.1	45,077.8	53,948.0	47,124.9	MWh	4 year trend (GS69 and G100 combined), factored for G100 based on FY26 estimate
Controlled 16h supply	GCOP	Discontinued 31/3/2026	571.2	556.3	593.0	482.7	259.6	305.3	-	MWh	Discontinued 31/3/2026
Night boost supply	G10N	Discontinued 31/3/2026	1.2	4.7	2.9	1.0	-	1.6	-	MWh	Discontinued 31/3/2026
Night only supply	GNEN	Discontinued 31/3/2026	158.7	108.8	126.6	109.8	44.3	-	-	MWh	Discontinued 31/3/2026
Anytime injection	GEDG		46.6	63.5	226.3	395.9	574.0	398.1	702.2	MWh	4 year trend (GS69 and G100 combined), factored for G100 based on FY26 estimate
Unmetered streetlighting	MCSL	Closed (no additions)	-	12.0	12.0	12.0	12.0	12.0	12.0	Fixtures	Forecast to remain at current level
Unmetered floodlighting	MCRF	Closed (no additions)	3.0	3.0	3.0	3.0	1.5	3.0	1.0	Fixtures	Forecast to remain at current level
Unmetered verandah lighting	MCRU	Closed (no additions)	1.0	1.0	1.0	1.0	-	-	-	Fixtures	Forecast to remain at current level
General 150kVA											
Fixed	G150		294.5	299.4	300.1	202.3	212.1	201.3	211.0	Connections	4 year linear trend, less those recategorised as G300
Anytime supply	GUEN		46,269.2	46,775.4	47,159.9	25,536.4	26,699.7	27,909.4	25,285.1	MWh	4 year linear trend G150 & G300 combined, then factored for G150 based on FY26 estimate
Controlled 16h supply	GCOP	Discontinued 31/3/2026	200.2	133.1	132.1	59.6	69.0	21.6	-	MWh	Discontinued 31/3/2026
Night boost supply	G10N	Discontinued 31/3/2026	-	-	-	-	-	-	-	MWh	Discontinued 31/3/2026
Night only supply	GNEN	Discontinued 31/3/2026	48.4	12.4	15.0	0.1	0.1	-	-	MWh	Discontinued 31/3/2026
Anytime injection	GEDG		40.6	62.7	600.8	372.4	678.6	725.0	916.7	MWh	4 year trend (G150 and G300 combined), factored for G150 based on FY26 estimate
General 300kVA											
Fixed	G300	New in FY25				101.4	104.7	99.0	108.0	Connections	2 year linear trend using updated estimate for FY26
Anytime supply	GUEN					16,548.2	16,149.6	20,961.0	15,290.5	MWh	4 year linear trend G150 & G300 combined, then factored for G300 based on FY26 estimate
Controlled 16h supply	GCOP	Discontinued 31/3/2026				14.9	38.1	14.8	-	MWh	Discontinued 31/3/2026
Night boost supply	G10N	Discontinued 31/3/2026				-	-	-	-	MWh	Discontinued 31/3/2026
Night only supply	GNEN	Discontinued 31/3/2026				-	-	-	-	MWh	Discontinued 31/3/2026
Anytime injection	GEDG					724.5	795.0	436.2	1,074.0	MWh	4 year trend (G150 and G300 combined), factored for G300 based on FY26 estimate
Irrigation											
Fixed charge	ISCH		1,605.1	1,608.5	1,608.7	1,607.1	1,619.3	1,613.6	1,618.6	Connections	4 year linear trend using updated estimate for FY26
Irrigation capacity	ISCH		140,007.5	140,875.4	141,204.5	142,758.1	145,253.1	142,317.3	146,194.5	kW	4 year linear trend using updated estimate for FY26
Average demand charge	ISAD	New in FY27							21,813.8	kW	Average demand charge - equivalent to total volume (kWh) divided by duration (h)
Anytime supply	IUEN		177,953.5	179,085.5	234,817.6	172,497.9	209,389.2	209,389.2	191,088.6	MWh	4 year average (excluding FY26 as we have no indication of summer volumes at time of forecast)
Anytime injection	IUDG		-	-	17.5	269.0	356.8	217.5	491.3	MWh	4 year linear trend using updated estimate for FY26
Fixed charge	ISCF		9.0	8.2	8.0	8.0	8.0	8.0	8.0	Connections	Set to current number of connections
Irrigation without harmonic mitigation	ISCF		874.0	830.6	829.0	829.0	829.0	829.0	829.0	kW	Set to current chargeable capacity (no changes anticipated)
Average demand charge	ISAD	New in FY27							134.7	kW	Average demand charge - equivalent to total volume (kWh) divided by duration (h)
Anytime supply	IUEN		991.2	1,045.0	1,418.2	891.4	1,231.6	1,231.6	1,180.4	MWh	3 year average to align with current customers (excluding FY26 as we have no indication of summer volumes at time of forecast)
Anytime injection	IUDG		-	-	-	-	-	-	-	MWh	Set to current year updated estimate
Fixed charge	ISCR	New in FY26				-	0.7	0.7	0.7	Connections	Set to quantities that would have been applied based on observed seasonal disconnection in FY24
Irrigation recovery	ISCR					-	54.5	54.5	54.5	kW	Set to quantities that would have been applied based on observed seasonal disconnection in FY24
Average demand charge	ISAD	New in FY27							8.1	kW	Average demand charge - equivalent to total volume (kWh) divided by duration (h)
Anytime supply	IUEN					-	80.2	80.2	71.2	MWh	Set to average consumption by kW
Anytime injection	IUDG					-	-	-	-	MWh	None expected

Category / Charge component			FY2022	FY2023	FY2024	FY2025	FY2026		FY2027	Units	Forecast method
	Code	Note	(actual)	(actual)	(actual)	(actual)	update estimate	(original budget)	(forecast)		
Industrial											
Fixed	IFIX	New in FY24	43.5	43.4	42.5	49.5	50.8	49.0	52.0	Connections	Set to latest actual total (17 Dec 2025))
Booked capacity	IBOK	New in FY24			16,685.4	21,133.5	21,754.7	20,803.0	22,320.0	kVA	Set to latest actual total (17 Dec 2025))
Average demand charge	ICAD	New in FY27							5,295.0	kW	Average demand charge - equivalent to total volume (kWh) divided by duration (h)
Anytime supply	ICEN		33,066.5	34,188.5	59,356.3	40,337.3	43,360.9	45,119.2	46,384.5	MWh	2 year linear trend using updated estimate for FY25 (limited history with current configuration)
Anytime injection	ICDG	New in FY24			0.2	108.0	56.0	23.8	56.0	MWh	Same as last year (very limited history of export)
Fixed	IFIX	New in FY25 (part year)			0.3	1.0	1.3	2.0	2.0	Connections	Set to latest actual total (17 Dec 2025))
Booked capacity HV	IBOH	New in FY25 (part year)			56.5	200.0	362.6	810.0	750.0	kVA	Set to latest actual total (17 Dec 2025))
Average demand charge	ICAD	New in FY27							19.6	kW	Average demand charge - equivalent to total volume (kWh) divided by duration (h)
Anytime supply	ICEN	New in FY25 (part year)			23.9	84.2	82.9	335.1	171.4	MWh	Set to updated estimate for FY25, factored by change in chargeable booked capacity
Anytime injection	ICDG	Nil prior to FY27							-	MWh	None expected
Fixed	IFIX	New in FY27							-	Connections	None expected - price category acts as deterrent to seasonal disconnection
Booked capacity Recovery	IBOR	New in FY27							-	kVA	
Average demand charge	ICAD	New in FY27							-	kW	Average demand charge - equivalent to total volume (kWh) divided by duration (h)
Anytime supply	ICEN	New in FY27							-	MWh	
Anytime injection	ICDG	New in FY27							-	MWh	
ANZCO Seafield											
Fixed charge	LUCM		1.0	1.0	1.0	1.0	2.4	1.0	2.0	Connections	Now has 3 connections (extra two connected 11/7/2025). Backup supply not separately charged, so 2 chargeable.
Booked capacity	LCCM	New in FY24			8,500.0	8,500.0	8,500.0	8,500.0	8,500.0	kVA	Fixed booked capacity
Anytime supply	LUEN		35,272.0	37,973.7	38,297.3	36,611.7	39,495.1	39,495.1	38,814.1	MWh	Updated estimate left as budget - longer than usual winter shutdown. 4 year linear trend using updated estimate for FY26
Talley's Fairfield 11kV											
Fixed charge	LUPP		1.0	1.0	1.0	1.0	1.0	1.0	1.0	Connections	Has a single connection
Booked capacity	LCPP	New in FY24			1,000.0	1,000.0	1,000.0	1,000.0	1,000.0	kVA	Fixed booked capacity
Anytime supply	LUEN		2,464.8	1,495.7	1,783.4	1,904.5	1,807.1	1,640.9	1,747.7	MWh	4 year average - no change in plant, so just normal variation
Talley's Ashburton											
Fixed charge	LUP2	New in FY24			1.0	1.0	1.0	1.0	1.0	Connections	Has a single connection
Booked capacity	LCP2	New in FY24			5,860.0	5,860.0	5,860.0	5,860.0	5,860.0	kVA	Fixed booked capacity
Anytime supply	LUEN	Split from ICMD	28,659.1	28,181.7	29,203.9	32,647.0	29,474.9	33,284.8	31,707.6	MWh	4 year linear trend using updated estimate for FY26
Talley's Fairfield 22kV											
Fixed charge	LUP3	New in FY24			1.0	1.0	1.0	1.0	1.0	Connections	Has a single connection
Booked capacity	LCP3	New in FY24			4,000.0	4,000.0	4,000.0	4,000.0	4,000.0	kVA	Fixed booked capacity
Anytime supply	LUEN				935.5	791.5	1,270.5	1,022.2	1,334.2	MWh	4 year linear trend using updated estimate for FY26
Mt Hutt Ski Field											
Fixed charge	LUMH		1.0	1.0	1.0	1.0	1.0	1.0	1.0	Connections	Has a single connection
Booked capacity	LCMH	New in FY24			3,000.0	3,000.0	3,000.0	3,000.0	3,000.0	kVA	Fixed booked capacity, Maintained at 3000 physical asset limit (some excess loading levels observed in FY25).
Anytime supply	LUEN		2,022.8	2,272.7	2,525.7	2,539.1	2,709.2	2,745.2	2,842.4	MWh	4 year linear trend using updated estimate for FY26
Highbank Pumps											
Fixed charge	LCHP	New in FY24			1.0	1.0	1.0	1.0	1.0	Connections	Has a single connection
Booked capacity	LUHP		9,600.0	9,600.0	9,600.0	9,600.0	9,600.0	9,600.0	9,600.0	kVA	Fixed booked capacity
Anytime supply	LUEN		1,447.6	1,992.7	8,375.8	4,431.6	2,289.3	4,206.7	4,061.9	MWh	4 year average excluding FY26 as we have no indication of summer volumes at time of forecast
Marley											
Fixed charge	LURX	New in FY24			2.0	2.0	2.0	2.0	2.0	Connections	Has two connections
Booked capacity	LCRX	New in FY24			4,000.0	4,000.0	4,000.0	4,000.0	4,000.0	kVA	Fixed booked capacity
Anytime supply	LUEN	Split from ICMD	5,914.0	5,915.0	4,026.3	4,418.3	5,336.0	5,058.8	4,923.9	MWh	Use 4 year average (consistent with last year), variability more significant than any trend.

Category / Charge component			FY2022	FY2023	FY2024	FY2025	FY2026		FY2027	Units	Forecast method
	Code	Note	(actual)	(actual)	(actual)	(actual)	update estimate	(original budget)	(forecast)		
Highbank Hydro											
Fixed charge	LUHB		1.0	1.0	1.0	1.0	1.0	1.0	1.0	Connections	Has a single connection
Anytime injection	LGDG		116,022.4	129,549.7	107,003.7	86,746.9	-	123,863.2	126,565.7	MWh	Out for service & upgrade in FY25/FY26. 2MW extra expected - factor prior average up by increase.
Montalto Hydro											
Fixed charge	LUMO		1.0	1.0	1.0	1.0	1.0	1.0	1.0	Connections	Has a single connection
Anytime injection	LGDG		9,651.4	9,120.2	8,946.3	8,137.9	8,509.9	8,509.9	8,964.0	MWh	Fixed equipment - use 4 year average
Cleardale Hydro											
Fixed charge	LUCD		1.0	1.0	1.0	1.0	1.0	1.0	1.0	Connections	Has a single connection
Anytime injection	LGDG		3,860.5	2,481.0	2,480.1	2,734.7	1,571.2	3,361.8	2,889.1	MWh	Fixed equipment - use 4 year average
Lavington Hydro											
Fixed charge	LULN		1.0	1.0	1.0	1.0	1.0	1.0	1.0	Connections	Has a single connection
Anytime injection	LGDG		3,134.3	2,772.8	2,858.7	1,816.5	2,871.1	2,871.1	2,645.6	MWh	Fixed equipment - use 4 year average
Lauriston Solar Farm											
Fixed charge	LURD	New in FY25				0.42	1.0	1.0	1.0	Connections	Has a single connection
Anytime injection	LGDG	New in FY25				27,131.7	88,070.0	88,070.0	88,070.0	MWh	Continue with output estimate provided by customer - full year operation not observed yet
Gartartan Solar Farm #1 (1MW)											
Fixed charge	LUGL	New in FY27 (split from LUGT)				0.3	1.0	1.0	1.00	Connections	Has a single connection (second connection now split off)
Anytime injection	LGDG	New in FY27 (split from LUGT)				-	-	-	1,732.6	MWh	Continue with prior estimate - full year operation not observed yet (split)
Gartartan Solar Farm #2 (6MW)											
Fixed charge	LUGT	New in FY26 (and split in two)				0.3	1.0	1.0	1.00	Connections	Has a single connection
Anytime injection	LGDG	New in FY26 (and split in two)					12,128.3	12,128.3	10,395.7	MWh	Continue with prior estimate - full year operation not observed yet (split)
Mt Somers Solar Farm											
Fixed charge	LUMS	Now not expected until FY28				-	-	0.4	-	Connections	Now not expected until FY2028
Anytime injection	LGDG	Now not expected until FY28				-		10,480.7	-	MWh	Now not expected until FY2028
Fairton Solar Farm											
Fixed charge	LUNF	New in FY26						-	1.0	Connections	Not expected and not budgetted for FY26. Has one connection
Anytime injection	LGDG	New in FY26						-	8,023.3	MWh	Not expected and not budgetted for FY26. Lauriston factored by size (Lauriston is 47.2MW, Fairton is 4.3MW)
Somerton Solar Farm											
Fixed charge	LUSO	Expected in FY27 (1 Dec 2026)							0.33	Connections	Has a single connection for a part year
Anytime injection	LGDG	Expected in FY27 (1 Dec 2026)							18,285.7	MWh	Lauriston output factored by size and expected part year of operation
Fords Road Solar Farm #1											
Fixed charge	LUFR	Expected in FY27 (1 Feb 2027)							0.16	Connections	Has a single connection for a part year
Anytime injection	LGDG	Expected in FY27 (1 Feb 2027)							1,554.9	MWh	Lauriston output factored by size and expected part year of operation
Streetlighting											
Unmetered street lighting	MCSL		3,672.4	3,755.8	3,844.6	3,947.9	4,029.7	4,003.4	4,125.7	Fixtures	4 year linear trend using updated estimate for FY26
Anytime supply	MESL		1,029.2	1,054.3	1,064.4	1,075.1	1,090.5	1,092.7	1,100.9	MWh	4 year linear trend using updated estimate for FY26

Appendix B Calculation of forecast revenue from prices

Connection category	Price category code	Price category	Price component	FY2027 Delivery Prices	FY2027 Forecast Quantities	Days applicable	Price x Quantity (\$000)
General supply	GS05, GS05-RL, GS05-UA	General Supply - 8 kVA	Capacity charge	0.4000 \$/con/day	445.3 cons	365 days	65.0
	GS20, GS20-RL, GS20-UA	General Supply - 20 kVA	Capacity charge	0.9000 \$/con/day	16,367.3 cons	365 days	5,376.7
	GS50, GS50-RL, GS50-UA	General Supply - 50 kVA	Capacity charge	2.2747 \$/con/day	1,845.7 cons	365 days	1,532.4
		+ Volume charges	Day of DNW	0.1080 \$/kWh	57,943.7 MWh		6,257.9
			Night & Weekend of DNW	0.0452 \$/kWh	62,319.7 MWh		2,816.9
			Controlled 16h supply	0.0514 \$/kWh	30,692.6 MWh		1,577.6
			Night boost supply	0.0474 \$/kWh	747.4 MWh		35.4
			Night only supply	0.0372 \$/kWh	2,786.2 MWh		103.6
			Anytime supply	0.1080 \$/kWh	5,246.0 MWh		566.6
		+ Export credits	Anytime injection	0.0000 \$/kWh	178.2 MWh		0.0
			Off-peak injection	0.0000 \$/kWh	1,567.7 MWh		0.0
			Peak injection (RL categories only)	(0.0692) \$/kWh	141.8 MWh		(9.8)
			Peak injection (UA categories only)	(0.2310) \$/kWh	15.8 MWh		(3.7)
	GS69	General Supply - 69 kVA	Capacity charge	7.9126 \$/con/day	363.8 cons	365 days	1,050.7
	G100	General Supply - 100 kVA	Capacity charge	12.9371 \$/con/day	468.6 cons	365 days	2,212.8
	G150	General Supply - 150 kVA	Capacity charge	16.9968 \$/con/day	211.0 cons	365 days	1,309.0
	G300	General Supply - 300 kVA	Capacity charge	23.3653 \$/con/day	108.0 cons	365 days	921.1
		+ Volume charges	Anytime supply	0.0616 \$/kWh	107,790.7 MWh		6,639.9
		+ Export credits	Anytime injection	0.0000 \$/kWh	2,901.4 MWh		0.0
		+ Other charges	Unmetered street lighting	0.2023 \$/fixture/day	21.0 fixtures	365 days	1.6
			Unmetered floodlighting	0.3888 \$/fixture/day	3.0 fixtures	365 days	0.4
			Unmetered verandah lighting	0.3423 \$/fixture/day	11.0 fixtures	365 days	1.4
Irrigation	ISCH	Irrigation	Capacity charge	0.4856 \$/kW/day	146,194.5 kW	365 days	25,912.1
			Average demand charge	0.2880 \$/kW/day	21,947.9 kW	365 days	2,307.2
	ISCF	Irrigation unfiltered	Capacity charge	0.6009 \$/kW/day	829.0 kW	365 days	181.8
			Average demand charge	0.2880 \$/kW/day	8.0 kW	365 days	0.8
	ISCR	Irrigation recovery	Capacity charge	0.9710 \$/kW/day	54.5 kW	365 days	19.3
			Average demand charge	0.2880 \$/kW/day	0.7 kW	365 days	0.1
Industrial	ICMD	Industrial	Fixed charge	16.0000 \$/con/day	52.0 cons	365 days	303.7
			Booked capacity charge	0.2489 \$/kVA/day	22,320.0 kVA	365 days	2,027.7
			Average demand charge	0.2880 \$/kW/day	5,295.0 kW	365 days	556.6
	ICMH	Industrial high voltage	Fixed charge	16.0000 \$/con/day	2.0 cons	365 days	11.7
			Booked capacity charge	0.2212 \$/kVA/day	750.0 kVA	365 days	60.6
			Average demand charge	0.2880 \$/kW/day	19.6 kW	365 days	2.1
	ICMR	Industrial recovery	Fixed charge	32.0000 \$/con/day	0.0 cons	365 days	0.0
			Booked capacity charge	0.4979 \$/kVA/day	0.0 kVA	365 days	0.0
			Average demand charge	0.2880 \$/kW/day	0.0 kW	365 days	0.0
Large Users	LUCM	ANZCO Seafield	Fixed charge	20.0000 \$/con/day	2.0 cons	365 days	14.6
			Booked capacity charge	0.4437 \$/kVA/day	8,500.0 kVA	365 days	1,376.6
	LUPP	Talley's Fairfield 11kV	Fixed charge	20.0000 \$/con/day	1.0 cons	365 days	7.3
			Booked capacity charge	0.1408 \$/kVA/day	1,000.0 kVA	365 days	51.4
	LUP2	Talley's Ashburton	Fixed charge	20.0000 \$/con/day	1.0 cons	365 days	7.3
			Booked capacity charge	0.5396 \$/kVA/day	5,860.0 kVA	365 days	1,154.2
	LUP3	Talley's Fairfield 22kV	Fixed charge	20.0000 \$/con/day	1.0 cons	365 days	7.3
			Booked capacity charge	0.0519 \$/kVA/day	4,000.0 kVA	365 days	75.8
	LUMH	Mt Hutt Ski Area	Fixed charge	20.0000 \$/con/day	1.0 cons	365 days	7.3
			Booked capacity charge	0.3449 \$/kVA/day	3,000.0 kVA	365 days	377.7
	LUHP	Highbank Pumps	Fixed charge	20.0000 \$/con/day	1.0 cons	365 days	7.3
			Booked capacity charge	0.1501 \$/kVA/day	9,600.0 kVA	365 days	526.0
Generation	LURX	Marley	Fixed charge	20.0000 \$/con/day	2.0 cons	365 days	14.6
			Booked capacity charge	0.2136 \$/kVA/day	4,000.0 kVA	365 days	311.9
	LUHB	Highbank hydro	Fixed charge	1,618.4859 \$/con/day	1.0 cons	365 days	590.7
	LUMO	Montalto hydro	Fixed charge	60.2740 \$/con/day	1.0 cons	365 days	22.0
	LUCD	Cleardale hydro	Fixed charge	107.5069 \$/con/day	1.0 cons	365 days	39.2
	LULN	Lavington hydro	Fixed charge	25.3484 \$/con/day	1.0 cons	365 days	9.3
	LURD	Lauriston solar farm	Fixed charge	1,218.7906 \$/con/day	1.0 cons	365 days	444.9
	LUGL	Gartartan solar farm #1	Fixed charge	3.4845 \$/con/day	1.0 cons	365 days	1.3
	LUGT	Gartartan solar farm #2	Fixed charge	12.6286 \$/con/day	1.0 cons	365 days	4.6
	LUNF	Fairton solar farm	Fixed charge	21.4776 \$/con/day	1.0 cons	365 days	7.8
	LUSO	Somerton solar farm	Fixed charge	393.8853 \$/con/day	1.0 cons	121 days	47.7
	LUFR	Fords Road solar farm #1	Fixed charge	183.9442 \$/con/day	1.0 cons	59 days	10.9
Street lighting	MCSL	Street Lighting	Unmetered street lighting	0.2023 \$/fixture/day	4,125.7 fixtures	365 days	304.6
			Anytime supply	0.0152 \$/kWh	1,100.9 MWh		16.7
Miscellaneous	NOCH	No charge, or charged elsewhere		0.0000 \$/con/day	4.0 cons	365 days	0.0
Other regulated revenue		Connection application fees					112.0
		Network damage recoveries					200.0
		DG application fees					102.0
		Gain (loss) on disposal					(300.0)
Total Forecast Revenue from Prices (FRFP)							67,391.8