2024-25 price list for the Western Power network

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1. Introduction

1.1 Overview

This document details Western Power's proposed price list for the pricing year commencing on 1 July 2024 and ending on 30 June 2025, which represents the third pricing year of Western Power's fifth access arrangement (AA5) period. We submit it for review and approval by the ERA as required by clause 8.1(b) of Chapter 8 of the *Electricity Networks Access Code 2004* (Access Code).

The prices within this price list will apply to all consumption during the pricing year.[1] Where consumption is metered with an accumulation meter and the meter reading interval causes some of the metered consumption to lie within the period covered by this price list and the remainder within a previous or subsequent period not covered by this price list, the consumption covered by this price list will be determined by prorating the metered consumption uniformly on a daily basis.

1.2 Key reforms

This document should be read in conjunction with Western Power's Reference Tariff Change Forecast and Tariff Structure Statement, as approved by the ERA as part of the approved AA5 access arrangement[2]; and published on Western Power's website in accordance with section 8.15 of the Access Code on 11 April 2023.[3]

The key pricing reforms adopted for the 2023-27 access arrangement period are:

- Introduction of new super off-peak time of use energy and demand reference tariffs for residential (RT35 and RT37) and small business customers (RT34 and RT36) to encourage customers to shift their consumption to the middle of the day when PV generation is plentiful.
- Introduction of new reference tariffs for grid-connected distribution (RT38 and RT39) and transmission voltage level connected storage (TRT3).
- Introduction of new reference tariffs for public Electric Vehicle charging stations (RT40 and RT41).
- Closure of the non-cost reflective time of use tariffs (introduced during AA4) to new customers.

1.3 Structure of this document

Section 2 lists the reference tariffs for the reference services provided by Western Power as stated in the access arrangement.

Section 3 outlines how Western Power applies reference tariffs to non-reference services.

Section 4 provides an overview of how Western Power applies bundled prices to reference tariffs and the application of reference tariffs to exit and bidirectional connection points.

Sections 5, and 6 detail the reference tariffs for users connected to our Distribution and Transmission networks, which are based on a number of components. The total charge payable by users under each

1 The prices in this Price List represent the network component of electricity tariffs only and are passed through to retailers before ultimately being passed on to end-use customers.

2 The AA5 final decision was published on the ERA's website on 31 March 2023 and can be found here: https://www.erawa.com.au/AA5.

3 The TSS documents can be found at, https://www.westernpower.com.au/about/regulation/network-access-prices/.

reference tariff represents the sum of the amounts payable for each component within the relevant reference tariff.

Section 7 sets out Western Power's other network tariffs, which include services ancillary to a covered service and several extended metering services.

Section 8 details the prices that are required to calculate the charges.

Section 9 details various fees that apply under the Applications and Queuing Policy.

Appendix A sets out Western Power's compliance with Chapter's 7 and 8 of the Access Code, including ensuring Western Power's reference tariffs comply with the revenue and pricing principles.

1.4 Revenue outcomes in 2024-25

1.4.1 Revenue targets for 2024-25

The following section details the calculation of the maximum total network revenue target (TNR_t) for Western Power's Transmission and Distribution networks.

TNR_t is determined as follows:

$$TNR_t = NR_t + TEC_t + DTEC_t$$

where:

TNR_t is the maximum total network revenue target services revenue for each financial year, t, of this access arrangement period

NR_t is the annual revenue target services revenue in financial year t

TEC_t is any cost incurred for the financial year t as a result of the tariff equalisation contribution in accordance with section 6.37A of the Code.

$DTEC_t$ is an adjustment for any shortfall or over recovery of actual distribution system revenue compared to TEC_t in preceding years and is calculated in accordance with section 5.7.4 of the access arrangement contract.

$DTEC_t$ is determined as follows:

$$DTEC_t = (FTEC_{t-2} - ATEC_{t-2}) * (1 + WACC_t) * (1 + WACC_{t-1}) + (TEC_{t-1} - FTEC_{t-1}) * (1 + WACC_t)$$

where:

$ATEC_t$ is the actual tariff equalisation contribution revenue received in financial year t.

$FTEC_t$ is the forecast of tariff equalisation contribution revenue to be received in financial year t.

TEC_t is the amount of tariff equalisation contribution to be recovered in a financial year t as gazetted.

$WACC_t$ is the weighted average cost of capital in year t for the Western Power Network as detailed in section 5.4 of the access arrangement contact, on a post-tax real basis.

Table 1.1 – Maximum total network revenue target for 2024-25 ($M nominal)

Maximum total target revenue	2023-24	2024-25
NR_t	1,638	1,754
TEC_t	173	199
$DTEC_t$	-4	+7
TNR_t	1,807	1,960

The total bundled system cost of supply cost pools and tariffs require the reference service revenue as an input in nominal terms. The following table details the bundled reference service revenue in nominal terms (please see section 1.4.2 for details of the inflation factor used).

Table 1.2 – Total target revenue for 2024-25 ($M)

Target Revenue	Revenue (Real)	Revenue (Nominal)
Target Revenue ($NR_{2024-25}$)	1,688	1,960

1.4.2 Derivation of Inflation Factor

In sections 1.4.1 and Table 1.2 Western Power has inflated the reference service revenue from real terms to nominal terms by using inflation in accordance with section 5.7.4 of the *access arrangement contract*.

Table 1.3 – Derivation of 2024-25 Inflation Factor

December 2020 – December 2021 – Actual	3.50%
December 2021 – December 2022 – Actual	7.80%
December 2022 – December 2023 – Actual	4.10%
Derived Inflation Factor	1.161

1.5 Proposed pricing strategy for 2024-25 price list

1.5.1 Overview of changes compared with the 2023-24 price list

Western Power has modified its approach to the pricing of some of its reference tariffs for the 2024-25 price list. This section sets out and describes the nature and extent of these changes from the previous pricing year and demonstrates that the changes comply with this Code and the TSS.

- General:
  - Western Power is proposing to continue prudently moving the transitional reference tariffs grandfathered at the beginning of AA5 towards cost reflectivity to encourage end-customers and retailers to churn these connection points to cheaper network tariffs that better signal the efficient use of our network.
  - To improve the overall consistency of the time of use pricing bands among our network tariffs, we are also proposing to alter the approach to setting the relative differences between the pricing of

the time of use bands of the transitional tariffs to align with those new tariffs introduced as part of AA5. That is, four pricing bands aligning to a super off-peak rate and/or overnight rate, off-peak rate, shoulder rate, and an on-peak rate, with a gradual rebalancing of the relativities between each rate to be broadly similar to each other across all of our time of use reference tariffs.

- Residential:
  - Multi part time of use energy residential (RT21): in previous price lists, Western Power sought to maintain the off-peak and overnight pricing bands at the same rate; however, as noted above as part of the proposed rebalancing for this price list, Western Power intends for these two rates to decouple over time with the relativity between the rates remaining consistent with that of other time of use tariffs. This proposed amendment would better embed the efficient signals included in the new AA5 time of use tariffs and encourage more efficient use of our network.
- Small business:
  - Multi part time of use energy business (RT22): as noted above, to improve the overall consistency of the time of use pricing bands among our network tariffs, Western Power is proposing to maintain the overnight and super off-peak pricing bands at the same rate but allow the off-peak rate to move overtime to a rate that is commensurate with the pricing relativities of other time of use business tariffs. This change is expected to affect approximately 250 customers.
  - Three-part, time of use energy business (RT18): we are proposing to charge a slightly higher fixed charge for this reference tariff compared with similar business tariffs. This is primarily because the total charges for RT18 customers are on average lower than that of customers on other business tariffs, and there is insufficient incentive for users to move these customers onto the more efficiently structured time of use tariffs introduced in AA5. To achieve the required rebalancing by changing the variable components alone would require increases of more than 50 per cent, which would make the variable components appear higher when compared with the other tariffs. Therefore, Western Power proposes to vary the fixed rate (which equates to an increase of $32 per customer per year compared with similar time of use tariffs).
- Streetlight tariffs:
  - As requested by the ERA in the 2023-24 Price List determination, a review has been undertaken of the costs allocated to the streetlight service asset charge and a transitional price path has been developed to achieve a cost reflective tariff.[4] The review resulted in a proposed reduction in the costs allocated to streetlight fixed asset charges. Taking account of the results of that review, the proposed price list includes an increase of 5.5 per cent to streetlight asset charges. Similar increases are forecast for the 2025/26 and 2026/27 price lists.

1.5.2 Comparison of weighted average price changes with reference tariff change forecast

The following sets out Western Power’s requirement to demonstrate compliance with the obligation for the weighted average price changes for each reference tariff to be consistent with the reference tariff change forecast compared with the previous pricing year.

Table 1.4 – Comparison of 2024-25 weighted average price changes with forecast weighted average price changes from the 2023-24 price list

[4] Economic Regulation Authority, *Determination on the proposed 2023-24 price list for the Western Power network – submitted by Western Power*, 17 May 2023, p.8.

Reference tariff	WAPC FY24 Price List - FY25 Pricing Year	WAPC FY25 Price List - FY25 Pricing Year	Variance
RT1 – Anytime Energy (Residential)	2.23%	9.53%	7.29%
RT2 – Anytime Energy (Business)	2.23%	9.20%	6.97%
RT3 – Time of Use Energy (Residential)^	9.02%	10.71%	1.69%
RT4 – Time of Use Energy (Business)^	11.06%	10.53%	-0.53%
RT5 – High Voltage Metered Demand	0.00%	9.33%	9.32%
RT6 – Low Voltage Metered Demand	0.23%	9.11%	8.88%
RT7 – High Voltage Contract Maximum Demand	0.86%	8.43%	7.57%
RT8 – Low Voltage Contract Maximum Demand	2.06%	6.93%	4.87%
RT9 – Streetlighting	- *	5.78%	
RT10 – Unmetered Supplies	2.00%	6.29%	4.29%
RT11 – Distribution Entry	2.33%	7.01%	4.68%
RT13 – Anytime Energy (Residential) Bi-directional	2.12%	9.47%	7.36%
RT14 – Anytime Energy (Business) Bi-directional	0.89%	8.74%	7.85%
RT15 – Time of Use (Residential) Bi-directional^	8.25%	10.99%	2.74%
RT16 – Time of Use (Business) Bi-directional^	10.94%	10.36%	-0.58%
RT17 – Time of Use Energy (Residential)*	9.09%	10.12%	1.04%
RT18 – Time of Use Energy (Business)*	14.87%	11.96%	-2.91%
RT19 – Time of Use Demand (Residential)*	3.98%	8.09%	4.11%
RT20 – Time of Use Demand (Business)*	10.02%	9.65%	-0.37%
RT21 – Multi Part Time of Use Energy (Residential)*	8.66%	11.81%	3.15%
RT22 – Multi Part Time of Use Energy (Business)*	14.12%	8.40%	-5.72%
RT34 – Super Off-peak Time of Use Energy (Business)**	2.78%	9.57%	6.79%
RT35 – Super Off-peal Time of Use Energy (Residential)**	3.16%	9.25%	6.09%
RT36 – Super Off-peak Time of Use Demand (Business)**	1.11%	7.75%	6.64%
RT37 – Super Off-peak Time of Use Demand (Residential)**	2.66%	9.50%	6.84%
RT38 – Low Voltage Distribution Storage**	5.50%	9.01%	3.51%
RT39 – High Voltage Distribution Storage**	6.00%	9.01%	3.01%
RT40 – Low Voltage Electric Vehicle Charging**	1.11%	9.35%	8.24%
RT41 – High Voltage Electric Vehicle Charging**	1.11%	9.32%	8.20%
Total Bundled Target Revenue from distribution customers	**6.13%**	**9.68%**	**3.55%**
TRT1 - Transmission exit	7.49%	6.95%	-0.53%

Reference tariff	WAPC FY24 Price List - FY25 Pricing Year	WAPC FY25 Price List - FY25 Pricing Year	Variance
TRT2 - Transmission entry	7.48%	6.62%	-0.86%
TRT3 - Transmission storage**	7.80%	6.01%	-1.79%
Total Bundled Target Revenue from transmission customers	**7.49%**	**6.77%**	**-0.72%**
Total Bundled Target Revenue	**6.21%**	**9.49%**	**3.28%**

Notes: * There was no forecast weighted average price increase included in the 2023-24 price list for RT9 by virtue of the ERA's signal to work with Western Power and streetlight customers to review and establish the costs of streetlight services and develop a transitional price path to achieve a cost reflective tariff as outlined in section 1.5.1 above.

There are a number of general factors that have contributed to the difference in the weighted average price change calculated in accordance with the 2024-25 price list compared with that forecast for the 2023-24 price list. The main drivers of the change are an increase in the:

- target revenue compared with that forecast last year;
- amount of TEC Western Power must pay to the State Government; and
- consumer price index compared with the expected regulatory consumer price index included in the tariff forecasts.

Table 1.4 shows the variance in the weighted average price change for the transitional reference tariffs (RT3-4, and RT15-22) is broadly consistent with that forecast in accordance with the 2023-24 price list. With these transitional tariffs essentially capped at their ceiling, the higher target revenue and TEC has required Western Power to increase its other distribution level tariffs beyond that forecast to enable it to recover total allowed revenue. As a result, tariffs that Western Power had intended to keep flat over AA5, including flat energy tariffs (RT1-2, and RT13-14), industrial customers (RT5-8), and the new time of use, storage, and EV tariffs (RT34-41) have needed to be increased more than forecast.

Western Power notes the reference tariff change forecast was amended on 15 August 2023 to correct the RT11 forecast for 2023-24 from 7.16% to 11.75%.[5] This amendment did not however change the weighted average price increases in RT11 for the 2024-25 pricing year and beyond. As a result, the variance outlined in Table 1.4 is not likely to reflect the actual price change.

1.6 Forecast revenue recovery

The following table sets out the reference service revenue, by network tariff, which is forecast to be collected when applying the 2024-25 Price List and the 2021 demand, customer and energy forecasts as required for compliance with Table 47 of the *access arrangement contract*.

[5] Western Power, *Reference tariff change forecast – revised table based on 2023-24 price list approved by the ERA*, 15 August 2023, p.1.

Table 1.5 – Bundled reference service revenue recovered from distribution and transmission connection points for 2024-25 ($M nominal)

Reference tariff	MWh	Customer numbers	Forecast bundled revenue recovered	Average price change
RT1 – Anytime Energy (Residential)	1,801,013	407,450	348.46	9.53%
RT2 – Anytime Energy (Business)	390,676	37,444	80.07	9.20%
RT3 – Time of Use Energy (Residential)^	17,556	2,955	3.23	10.71%
RT4 – Time of Use Energy (Business)^	146,278	1,848	19.65	10.53%
RT5 – High Voltage Metered Demand	675,052	324	45.36	9.33%
RT6 – Low Voltage Metered Demand	1,663,959	3,721	136.30	9.11%
RT7 – High Voltage Contract Maximum Demand	3,346,400	387	206.57	8.43%
RT8 – Low Voltage Contract Maximum Demand	268,833	53	14.54	6.93%
RT9 – Streetlighting	140,037	297,685	50.55	5.78%
RT10 – Unmetered Supplies	47,720	20,162	7.19	6.29%
RT11 – Distribution Entry	197	27	5.21	7.01%
RT13 – Anytime Energy (Residential) Bi-directional	866,314	189,557	164.88	9.47%
RT14 – Anytime Energy (Business) Bi-directional	17,218	1,200	3.17	8.74%
RT15 – Time of Use (Residential) Bi-directional^	26,111	5,116	5.05	10.99%
RT16 – Time of Use (Business) Bi-directional^	35,220	247	4.54	10.36%
RT17 – Time of Use Energy (Residential)*	553,875	88,838	89.49	10.12%
RT18 – Time of Use Energy (Business)*	345,079	16,496	60.76	11.96%
RT19 – Time of Use Demand (Residential)*	9,716	133	0.88	8.09%
RT20 – Time of Use Demand (Business)*	38,781	247	6.64	9.65%
RT21 – Multi Part Time of Use Energy (Residential)*	1,600,835	372,518	318.51	11.81%
RT22 – Multi Part Time of Use Energy (Business)*	13,688	247	2.05	8.40%
RT34 – Super Off-peak Time of Use Energy (Business)**	1,006,180	48,100	148.88	9.57%
RT35 – Super Off-peal Time of Use Energy (Residential)**	39,716	9,242	7.74	9.25%
RT36 – Super Off-peak Time of Use Demand (Business)**	213,217	1,358	34.33	7.75%
RT37 – Super Off-peak Time of Use Demand (Residential)**	157,648	36,685	73.09	9.50%
RT38 – Low Voltage Distribution Storage**	0	5	1.15	9.01%
RT39 – High Voltage Distribution Storage**	0	5	1.15	9.01%
RT40 – Low Voltage Electric Vehicle Charging**	332	20	0.19	9.35%
RT41 – High Voltage Electric Vehicle Charging**	66	4	0.12	9.32%

Reference tariff	MWh	Customer numbers	Forecast bundled revenue recovered	Average price change
Total Bundled Target Revenue from distribution customers	**13,421,716**	**1,542,073**	**1,839.76**	**9.68%**
TRT1 - Transmission exit	743	42	56.66	6.95%
TRT2 - Transmission entry	5,435	38	62.64	6.62%
TRT3 - Transmission storage**	0	2	1.32	6.01%
Total Bundled Target Revenue from transmission customers	**6,178**	**82**	**120.62**	**6.77%**
Total Bundled Target Revenue	**13,427,894**	**1,542,155**	**1,960.37**	**9.49%**

Note: ^ denotes reference tariffs that were closed to new customer nominations on 1 July 2019.
* denotes reference tariffs that will be closed to new customer nominations from 1 July 2023.
** denotes reference tariffs introduced in AA5 and available from 1 July 2023.

2. References services

The following table details which reference tariff is applicable to each of the reference services.

Table 2.1: Reference services and applicable tariffs and billing codes

Reference service	Reference tariff	MBS Code
A1 – Anytime Energy (Residential) Exit Service	RT1	AER
A2 – Anytime Energy (Business) Exit Service	RT2	AEB
A3 – Time of Use Energy (Residential) Exit Service	RT3	TOUS
A4 – Time of Use Energy (Business) Exit Service	RT4	TOUL
A5 – High Voltage Metered Demand Exit Service C5 – High Voltage Metered Demand Bi-directional Service	RT5	HVMD
A6 – Low Voltage Metered Demand Exit Service C6 – Low Voltage Metered Demand Bi-directional Service	RT6	LVMD
A7 – High Voltage Contract Maximum Demand Exit Service C7 – High Voltage Contract Maximum Demand Bi-directional Service	RT7	HVCMD
A8 – Low Voltage Contract Maximum Demand Exit Service C8 – Low Voltage Contract Maximum Demand Bi-directional Service	RT8	LVCMD
A9 – Streetlighting Exit Service	RT9	SLS
A10 – Unmetered Supplies Exit Service	RT10	UMS
A11 – Transmission Exit Service	TRT1	TREX
B1 – Distribution Entry Service	RT11	DEN
B2 – Transmission Entry Service	TRT2	TREN
C1 – Anytime Energy (Residential) Bi-directional Service	RT13	BAER
C2 – Anytime Energy (Business) Bi-directional Service	RT14	BAEB
C3 – Time of Use (Residential) Bi-directional Service	RT15	BTOUS
C4 – Time of Use (Business) Bi-directional Service	RT16	BTOUL
A12 – 3 Part Time of Use Energy (Residential) Exit Service C9 – 3 Part Time of Use Energy (Residential) Bi-directional Service	RT17	TTOUS
A13 – 3 Part Time of Use Energy (Business) Exit Service C10 – 3 Part Time of Use Energy (Business) Bi-directional Service	RT18	TTOUL
A14 – 3 Part Time of Use Demand (Residential) Exit Service C11 – 3 Part Time of Use Demand (Residential) Bi-directional Service	RT19	DTOUS

Reference service	Reference tariff	MBS Code
A15 – 3 Part Time of Use Demand (Business) Exit Service C12 – 3 Part Time of Use Demand (Business) Bi-directional Service	RT20	DTOUL
A16 – Multi Part Time of Use Energy (Residential) Exit Service C13 – Multi Part Time of Use Energy (Residential) Bi-directional Service	RT21	MTOUS
A17 – Multi Part Time of Use Energy (Business) Exit Service C14 – Multi Part Time of Use Energy (Business) Bi-directional Service	RT22	MTOUL
B3 – Entry Service Facilitating a Distributed Generation or Other Non-Network Solution	RT23	
C15 – Bi-directional Service Facilitating a Distributed Generation or Other Non-Network Solution	RT24	
D1 – Supply Abolishment Service	RT25	
D2 – Capacity Allocation Service	NA6	
D6 – Remote Load / Inverter Control Service	RT26	
D8 – Remote De-energise Service	RT28	
D9 – Remote Re-energise Service	RT29	
D10 – Streetlight LED Replacement Service	RT30	
D11 – Site Visit to Support Remote Re-energise Service	RT31	
D12 – Manual De-energise Service	RT32	
D13 – Manual Re-energise Service	RT33	
A19 – Super Off-peak Energy (Business) Exit Service C17 – Super Off-peak Energy (Business) Bi-directional Service	RT34	STOUL
A18 – Super Off-peak Energy (Residential) Exit Service C16 – Super Off-peak Energy (Residential) Exit Service	RT35	STOUS
A21 – Super Off-peak Demand (Business) Exit Service C19 – Super Off-peak Demand (Business) Bi-directional Service	RT36	DSTOUL
A20 – Super Off-peak Demand (Residential) Exit Service C18 – Super Off-peak Demand (Residential) Bi-directional Service	RT37	DSTOUS
C22 – Transmission Storage Service	TRT3	TRST
C23 – Low Voltage Distribution Storage Service	RT38	LVST
C24 – High Voltage Distribution Storage Service	RT39	HVST
A22 – Low Voltage Electric Vehicle Charging Exit Service C20 – Low Voltage Electric Vehicle Charging Bidirectional Service	RT40	LVEV

[6] Applicable Reference Tariff: Any applicable lodgement fees payable in accordance with the Applications and Queuing Policy.

Reference service	Reference tariff	MBS Code
A23 – High Voltage Electric Vehicle Charging Exit Service C21 – High Voltage Electric Vehicle Charging Bidirectional Service	RT41	HVEV

3. Non-reference services

Where Western Power is providing a user a non-reference service at a connection point, the tariff applicable to that non-reference service is the tariff agreed between the user and Western Power.

4. Application of tariffs

4.1 Bundled charges for reference tariffs

Within this price list the transmission and distribution components of the bundled charges are published, where applicable. The bundled charge is applicable when calculating the charge for the reference tariff, unless otherwise indicated. The bundled charge is the sum of the distribution and transmission components of the charge.

At Western Power's discretion, the charges detailed below may be discounted where there are multiple exit points on the same premises that are configured in a non-standard way. These discounts include, but are not limited to, only charging one administration charge per site.

4.2 Application of reference tariffs to exit and bi-directional points

Reference tariffs RT5 to RT8, RT17 to RT22, and RT34 to RT41 are applicable to reference services at connection points that may be exit points or bi-directional points.

With the exception of the low voltage and high voltage storage tariffs (please add the relevant RTs) that measure the net consumption of energy transferred into and out of the Western Power network at the connection point, the energy or demand charges are calculated based on energy being transferred out of the network only.

5. Distribution Tariffs

5.1 Anytime energy (RT1 and RT2)

RT1 and RT2 consist of:

a. a fixed use of system charge (detailed in Table 8.1) which is payable each day;

b. a variable use of system charge calculated by multiplying the energy price (detailed in Table 8.1) by the quantity of electricity consumed at an exit point (expressed in kWh); and

c. a fixed metering charge per revenue meter calculated in accordance with section 8.2.3 (detailed in Table 8.14 and Table 8.15) which is payable each day.

5.2 Time of use energy (RT3 and RT4)

RT3 and RT4 consist of:

d. a fixed use of system charge (detailed in Table 8.1) which is payable each day;

e. an on-peak use of system variable charge calculated by multiplying the on-peak energy price (detailed in Table 8.1) by the quantity of on-peak electricity consumed at an exit point (expressed in kWh);

f. an off-peak use of system variable charge calculated by multiplying the off-peak energy price (detailed in Table 8.1) by the quantity of off-peak electricity consumed at an exit point (expressed in kWh); and

g. a fixed metering charge per revenue meter calculated in accordance with section 8.2.3 (detailed in Table 8.14 and Table 8.15) which is payable each day.

Notes:

1. The on and off-peak periods for these tariffs are defined in the following table (all times are Western Standard Time (WST)):

Table 5.1: RT3 and RT4

	Monday – Friday (includes public holidays)			Saturday – Sunday (excludes public holidays)
	Off-peak	**On-Peak**	**Off-Peak**	**Off-Peak**
RT3	12:00am – 7:00am	7:00am – 9:00pm	9:00pm – 12:00am	All times
RT4	12:00am – 8:00am	8:00am – 10:00pm	10:00pm – 12:00am	All times

5.3 High voltage metered demand (RT5)

5.3.1 Tariff calculation

RT5 consists of:

a. a fixed metered demand charge (detailed in Table 8.9) which is payable each day based on the rolling 12-month maximum half-hourly demand at a connection point (expressed in kVA) multiplied by (1-Discount);

b. a variable metered demand charge calculated by multiplying the demand price (in excess of the lower threshold and detailed in Table 8.9) by the rolling 12-month maximum half-hourly demand at a connection point (expressed in kVA) minus the lower threshold with the result multiplied by (1-Discount);

c. if the metered demand is greater than 1,000 kVA a variable demand length charge calculated by multiplying the demand length price (detailed in Table 8.12) by the electrical distance to the zone substation by the rolling 12-month maximum half-hourly demand (expressed in kVA) minus 1,000 kVA (Note: a different rate applies after 10 km); and

d. a fixed metering charge per revenue meter calculated in accordance with section 8.2.3 (detailed in Table 8.14 and Table 8.15) which is payable each day.

Notes:

1. If a user reduces its rolling 12-month maximum half-hourly demand at a connection point as set out in the process in section 5.3.3 below, then for the purposes of calculating parts a, b and c of the RT5 tariff the 'rolling 12-month maximum half-hourly demand' shall be the reduced amount from the date approved by Western Power.
2. The on and off-peak periods for this tariff are defined in the following table (all times are WST):

Table 5.2: On and off-peak for RT5

Monday – Friday (excludes public holidays)			Saturday – Sunday (includes public holidays)
Off-peak	**On-Peak**	**Off-Peak**	**Off-Peak**
12:00am – 3:00pm	3:00pm – 9:00pm	9:00pm – 12:00am	All times

5.3.2 Discount

A discount, based on the percentage of off-peak energy consumption (as a proportion of the total energy consumption), applies to this tariff.

The Discount is defined as:

For MD < 1,000 kVA $(E_{Off\text{-}peak}/E_{Total}) * DF$

For 1,000 <= MD <1,500 kVA $((1500 - MD)/500) * (E_{Off\text{-}peak}/E_{Total}) * DF$

For MD => 1,500 kVA 0

Where:

MD is the rolling 12-month maximum half-hourly demand at a connection point (expressed in kVA);

DF is the discount factor, which is set at 30%;

$E_{Off\text{-}peak}$ is the total off-peak energy for the billing period (expressed in kWh); and

E_{Total} is the total energy (both on and off-peak) for the billing period (expressed in kWh).

Notes:

1. This discount does not apply to the demand-length portion of the charge.

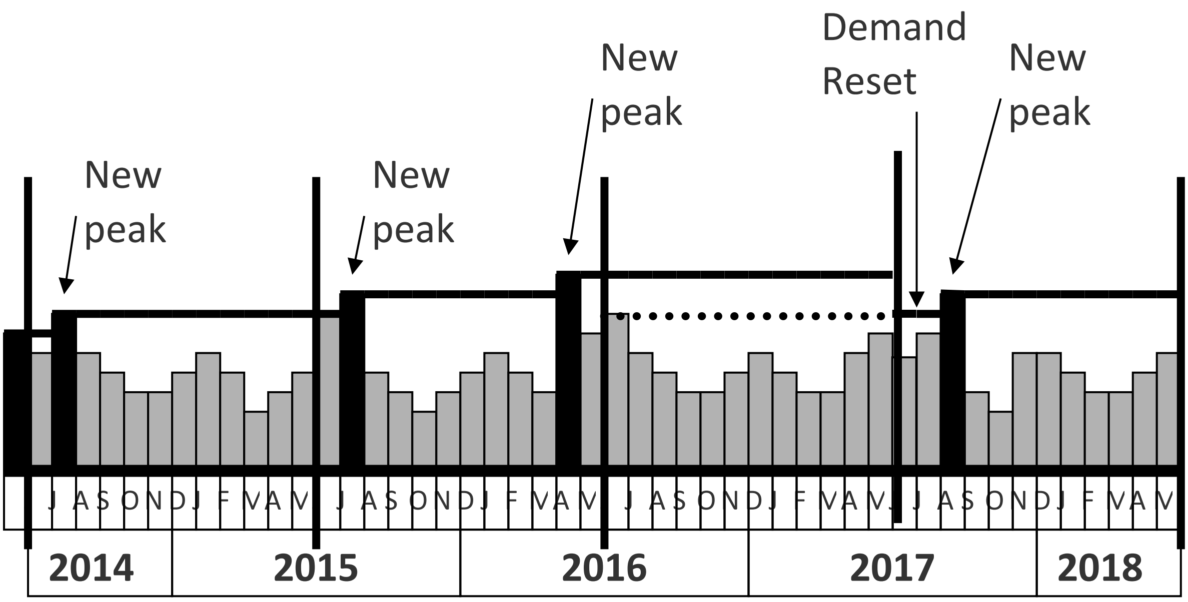
5.3.3 Derivation of rolling 12-month peak

The metered demand tariff is based on a metered annual any time maximum demand with a discount to give credit for off-peak energy usage as a proportion of total energy used.

The annual any time maximum demand is the rolling peak value over the previous 12 months. This rolling peak, rather than a monthly-metered peak, is chosen for compatibility with the CMD tariffs that are based on a contracted maximum demand set for a defined period. A tariff based on a metered monthly peak would need to be higher to recover the same revenue from these users due to the effect of seasonal variation in loads.

The principle of using this rolling peak is illustrated in Figure 5.1.

Figure 5.1: Rolling Peak Illustration



There is no excess network usage charge for this tariff. The incentive to control the peak demand is significant because any half-hourly excess peak would be retained in the charges for a full 12 months. However, this is not intended to be unreasonably punitive to users and the negative impact of an extraordinary event would be assessed on a case-by-case basis.

If a user, or its customer, has implemented initiatives to reduce the future maximum demand on a permanent basis including:

- the implementation of load control, energy efficiency equipment or solutions at the connection point; or
- a fundamental change in the nature of the business or operation conducted at the connection point; or
- a shutdown of the business or operation conducted at the connection point; or
- some other special circumstance or arrangement that reduces the maximum demand at the connection point,

then the user may apply to Western Power for the rolling 12-month period and maximum metered demand to be reset.

The application must include a forecast of maximum demand over the future 12-month period, details of why the user expects the demand will be lower, evidence to support the change and the date the user wishes the revised maximum metered demand to apply from. If Western Power considers, as a reasonable and prudent person and in accordance with good electricity industry practice, that the revised maximum metered demand is reasonable, Western Power must reset the rolling 12-month period and maximum demand in line with the application.

If the actual maximum metered demand exceeds the reset maximum metered demand within 12 months of the reset, an adjustment will be made to charges as though the actual maximum metered demand had applied from the date the reset was implemented.

The off-peak discount is applied monthly, based on the metered off-peak and total energy amounts. The discount is intended to create an incentive for users to use the network off-peak and is provided as a specific reduction in the monthly charge depending on the proportion of off-peak energy used.

The tariff also includes a 'demand-length' component for demands greater than 1,000 kVA, identical to that applying in the CMD tariffs, based on the rolling annual peak.

The demand price is in rate block format. The transition points are set at 300 kVA and 1,000 kVA and the discount phases out at 1,500 kVA. At 1,500 kVA the tariff is set to be less attractive than the CMD tariffs for most users.

A discount mechanism applies to this tariff as defined in section 5.3.2 above.

5.4 Low voltage metered demand (RT6)

5.4.1 Tariff calculation

RT6 consists of:

a. a fixed metered demand charge (detailed in Table 8.10) which is payable each day based on the rolling 12-month maximum half-hourly demand at a connection point (expressed in kVA) multiplied by (1-Discount);

b. a variable metered demand charge (detailed in Table 8.10) calculated by multiplying the demand price (in excess of lower threshold) by the rolling 12-month maximum half-hourly demand at a connection point (expressed in kVA) minus the lower threshold with the result multiplied by (1-Discount);

c. if the metered demand is greater than 1,000 kVA a variable demand length charge calculated by multiplying the demand length price (detailed in Table 8.12) by the electrical distance to the zone substation by the rolling 12-month maximum half-hourly demand (expressed in kVA) minus 1,000 kVA (Note: a different rate applies after 10 km); and

d. a fixed metering charge per revenue meter calculated in accordance with section 8.2.3 (detailed in Table 8.14 and Table 8.15) which is payable each day.

Notes:

1. This tariff is similar to RT5 in section 5.3 but for customers connected at low voltage. The higher tariff rates reflect the additional cost of using the low voltage network.
2. The on and off-peak periods for this tariff are defined in the following table (all times are WST):

Table 5.3: On and off-peak for RT6

Monday – Friday (excludes public holidays)			Saturday – Sunday (includes public holidays)
Off-peak	**On-Peak**	**Off-Peak**	**Off-Peak**
12:00am – 3:00pm	3:00pm – 9:00pm	9:00pm – 12:00am	All times

3. If a user reduces its rolling 12-month maximum half-hourly demand at a connection point as set out in the process in section 5.4.3 below, then for the purposes of calculating parts a, b and c of the RT6 tariff the 'rolling 12-month maximum half-hourly demand' shall be the reduced amount from the date approved by Western Power.

5.4.2 Discount

The same formula detailed in section 5.3.2 also applies for RT6.

5.4.3 Derivation of 12-month rolling peak

The same processes detailed in section 5.3.3 also applies for RT6.

5.5 High voltage contract maximum demand (RT7)

5.5.1 Tariff calculation

RT7 consists of:

a. If the contracted maximum demand (CMD) is less than 7,000 kVA:
    i. a fixed demand charge for the first 1,000 kVA (detailed in Table 8.11) which is payable each day; plus
    ii. a variable demand charge calculated by multiplying the applicable demand price (detailed in Table 8.11) by the CMD (expressed in kVA) minus 1,000 kVA; plus
    iii. a variable demand length charge calculated by multiplying the demand length price (detailed in Table 8.12) by the electrical distance to the zone substation by the CMD (expressed in kVA) minus 1,000 kVA (Note: a different rate applies after 10 km);
b. If the CMD is equal to or greater than 7,000 kVA:
    i. a variable demand charge calculated by multiplying the applicable demand price (detailed in Table 8.11) by the CMD (expressed in kVA); plus
    ii. a variable demand length charge calculated by multiplying the demand length price (detailed in Table 8.13) by the electrical distance to the zone substation by the CMD (expressed in kVA) (Note: a different rate applies after 10 km);
c. a fixed metering charge per revenue meter calculated in accordance with section 8.2.3 (detailed in Table 8.14 and Table 8.15) which is payable each day;
d. a fixed administration charge (detailed in Table 8.17) which is payable each day; and
e. excess network usage charges calculated in accordance with section 5.5.2 (if applicable).

Notes:

1. For connection points located at the zone substation the fixed and variable demand charge specified in sections 5.5.1(a)(i), (a)(ii) & (b)(i) is to be calculated using the transmission component only. In all other instances, the fixed and variable demand charge specified in sections 5.5.1 (a)(i), (a)(ii) & (b)(i) is to be calculated using the bundled charge.
2. If this tariff applies in relation to a connection point the subject of a capacity allocation arrangement pursuant to reference services D2 as set out in Appendix E of the Access Arrangement, then the charge to each user at this connection point for the duration of the capacity allocation arrangement is the sum of all tariff components a to d, multiplied by the percentage of the contracted capacity allocated to the user pursuant to the capacity allocation arrangement as compared to the total contracted capacity at the connection point.

5.5.2 Excess network usage charges

An additional charge applies to this tariff where the peak half-hourly demand exceeds the nominated CMD during the billing period of the load.

The excess network usage charge (ENUC) is calculated by applying a factor to the excess usage as follows:

$$ENUC = ENUC_{Transmission} + ENUC_{Distribution}$$

Where:

$ENUC_{Transmission}$	$= ENUM * (PD – CMD) * DC_{Transmission} / CMD$;
$ENUC_{Distribution}$	$= ENUM * (PD – CMD) * (DC_{Distribution} + DLC) / CMD$;
ENUM	is the Excess network usage multiplier factor, which is defined in Table 8.25;
PD	is the peak half-hourly demand during the billing period of the load (expressed in kVA);
CMD	is the nominated CMD for the billing period of the load (expressed in kVA);
$DC_{Transmission}$	are the applicable transmission components of the fixed and variable demand charges for the billing period for the nominated CMD;
$DC_{Distribution}$	are the applicable distribution components of the fixed and variable demand charges for the billing period for the nominated CMD; and
DLC	are the applicable variable demand length charges for the billing period for the nominated CMD.

Notes:

1. The ENUC does not include the metering or administration components of the tariff.
2. If the connection point is subject to the Capacity (Swap) Allocation (Business) Exit Service, for the purposes of the ENUC calculation above the CMD is the total contracted capacity allocated to the connection point from time to time pursuant to the capacity allocation arrangement.

5.6 Low voltage contract maximum demand (RT8)

5.6.1 Tariff calculation

RT8 consists of:

a. If the contracted maximum demand (CMD) is less than 7,000 kVA:

   i. a fixed demand charge for the first 1,000 kVA (detailed in Table 8.11) which is payable each day; plus

   ii. a variable demand charge calculated by multiplying the applicable demand price (detailed in Table 8.11) by the CMD (expressed in kVA) minus 1,000 kVA; plus

   iii. a variable demand length charge calculated by multiplying the demand length price (detailed in Table 8.12) by the electrical distance to the zone substation by the CMD (expressed in kVA) minus 1,000 kVA (Note: a different rate applies after 10 km);

b. If the CMD is equal to or greater than 7,000 kVA:

   i. a variable demand charge calculated by multiplying the applicable demand price (detailed in Table 8.11) by the CMD (expressed in kVA); plus

   ii. a variable demand length charge calculated by multiplying the demand length price (detailed in Table 8.13) by the electrical distance to the zone substation by the CMD (expressed in kVA) (Note: a different rate applies after 10 km);

c. a fixed low voltage charge (detailed in Table 8.18) which is payable each day;

d. a variable low voltage charge calculated by multiplying the low voltage demand price (detailed in Table 8.18) by the CMD (expressed in kVA);

e. a fixed metering charge per revenue meter calculated in accordance with section 8.2.3 (detailed in Table 8.14 and Table 8.15) which is payable each day;

f. a fixed administration charge (detailed in Table 8.17) which is payable each day; and

g. excess network usage charges calculated in accordance with section 5.6.2 (if applicable).

Notes:

1. This tariff is identical to RT7 in section 5.5, with an additional low voltage charge to cover the use of transformers and LV circuits.
2. If this tariff applies in relation to a connection point the subject of a capacity allocation arrangement pursuant to reference services D2 as set out in Appendix E of the Access Arrangement, then the charge to each user at this connection point for the duration of the capacity allocation arrangement is the sum of all tariff components a to d, multiplied by the percentage of the contracted capacity allocated to the user pursuant to the capacity allocation arrangement as compared to the total contracted capacity at the connection point.

5.6.2 Excess network usage charges

An additional charge applies to this tariff where the peak half-hourly demand exceeds the nominated CMD during the billing period of the load. The excess network usage charge (ENUC) is calculated by applying a factor to the excess usage as follows:

$ENUC = ENUC_{Transmission} + ENUC_{Distribution}$

Where

$ENUC_{Transmission}$	$= ENUM * (PD – CMD) * DC_{Transmission} / CMD$;
$ENUC_{Distribution}$	$= ENUM * (PD – CMD) * (DC_{Distribution} + DLC + LVC) / CMD$;
ENUM	is the Excess network usage multiplier factor, which is defined in Table 8.25;
PD	is the peak half-hourly demand during the billing period of the load (expressed in kVA);
CMD	is the nominated CMD for the billing period of the load (expressed in kVA);
$DC_{Transmission}$	are the applicable transmission components of the fixed and variable demand charges for the billing period for the nominated CMD;
$DC_{Distribution}$	are the applicable distribution components of the fixed and variable demand charges for the billing period for the nominated CMD;
DLC	are the applicable variable demand length charges for the billing period for the nominated CMD; and
LVC	are the applicable additional fixed and additional demand (low voltage) charges for the billing period for the nominated CMD.

Notes:

1. The ENUC does not include the metering or administration components of the tariff.
2. If the connection point is subject to the Capacity (Swap) Allocation (Business) Exit Service, for the purposes of the ENUC calculation above the CMD is the total contracted capacity allocated to the connection point from time to time pursuant to the capacity allocation arrangement.

5.7 Streetlighting (RT9)

RT9 consists of:

a. a fixed use of system charge (detailed in Table 8.1) which is payable each day;

b. a variable use of system charge calculated by multiplying the energy price (detailed in Table 8.1) by the estimated quantity of electricity consumed at an exit point (expressed in kWh and is based on the lamp wattage and illumination period); and

c. a fixed asset charge based on the type of streetlight asset supplied (detailed in Table 8.7 and Table 8.8)

5.8 Unmetered supply (RT10)

RT10 consists of:

a. a fixed use of system charge (detailed in Table 8.1) which is payable each day; and

b. a variable use of system charge calculated by multiplying the energy price (detailed in Table 8.1 by the estimated quantity of electricity consumed at an exit point (expressed in kWh and based on the nameplate rating of the connected equipment and the hours of operation).

Except for where the consumer's facilities and equipment is a streetlight, then Reference Tariff RT10 consists of:

a. the fixed use of system charge for RT9 (detailed in Table 8.1) which is payable each day; and
b. the variable use of system charge for RT9 calculated by multiplying the energy price (detailed in Table 8.1by the estimated quantity of electricity consumed at an exit point (expressed in kWh and based on the nameplate rating of the connected equipment and the hours of operation).

5.9 Distribution entry service (RT11)

5.9.1 Tariff calculation

RT11 consists of:

a. a variable connection charge calculated by multiplying the connection price (detailed in Table 8.19) by the loss-factor adjusted declared sent-out capacity (DSOC) at the entry point (expressed in kW);
b. a variable control system service charge calculated by multiplying the control system service price (detailed in Table 8.23) by the nameplate output of the generator at the entry point (expressed in kW);
c. a variable use of system charge calculated by multiplying the use of system price (based on the location of the electrically closest major generator and detailed in Table 8.21) by the loss-factor adjusted DSOC at the entry point (expressed in kW);
d. if the DSOC is less than 7,000 kVA:
    i. if the entry point is connected at 415 V or less and the DSOC is equal to or greater than 1,000 kVA a variable demand length charge calculated by multiplying the applicable demand length price (detailed in Table 8.12) by the electrical distance between the relevant HV network connection point and the electrically closest zone substation by the DSOC (expressed in kVA) minus 1,000 kVA (Note: a different rate applies after 10 km); or
    ii. if the entry point is connected at greater than 415 V and the DSOC is equal to or greater than 1,000 kVA a variable demand length charge calculated by multiplying the applicable demand length price (detailed in Table 8.12) by the electrical distance between the entry point and the electrically closest zone substation by the DSOC (expressed in kVA) minus 1,000 kVA (Note: a different rate applies after 10 km);
e. If the DSOC is equal to or greater than 7,000 kVA:
    i. if the entry point is connected at 415 V or less a variable demand length charge calculated by multiplying the applicable demand length price (detailed in Table 8.13) by the electrical distance between the relevant HV network connection point and the electrically closest zone substation by the DSOC (expressed in kVA) (Note: a different rate applies after 10 km); or
    ii. if the entry point is connected at greater than 415 V a variable demand length charge calculated by multiplying the applicable demand length price (detailed in Table 8.13) by the electrical distance between the entry point and the electrically closest zone substation by the DSOC (expressed in kVA) (Note: a different rate applies after 10 km);
f. a fixed metering charge per revenue meter calculated in accordance with section 8.2.3 (detailed in Table 8.14 and Table 8.15) which is payable each day; and
g. excess network usage charges calculated in accordance with section 5.9.2 (if applicable).

Notes:

1. The loss factor used to calculate the loss-factor adjusted DSOC is the relevant portion from the generator to the zone substation of the loss factor published by the AEMO for that generator.
2. For this reference tariff a unity power factor is assumed when converting between kW and kVA.

5.9.2 Excess network usage charges

An additional charge applies to this tariff where the peak half-hourly demand exceeds the nominated DSOC during the billing period except where Western Power deems the export of power in excess of DSOC was required for power system reliability and security purposes.

The excess network usage charge (ENUC) is calculated by applying a factor to the excess usage as follows:

$$ENUC = ENUC_{Transmission} + ENUC_{Distribution}$$

Where

$$ENUC_{Transmission} = ENUM * (PD_{kW} – DSOC_{kW}) * TEPC / DSOC_{kW};$$

$$ENUC_{Distribution} = ENUM * (PD_{kVA} – DSOC_{kVA}) * (DLC) / DSOC_{kVA};$$

ENUM	is the Excess network usage multiplier factor, which is defined in Table 8.25;
PD	is the peak half-hourly demand during the billing period (expressed in kVA and kW);
DSOC	is the nominated DSOC for the billing period (expressed in kVA and kW);
TEPC	is the sum of the variable connection charge, variable control system service charge and variable use of system charge for the billing period for the nominated DSOC; and
DLC	is the applicable variable demand length charge for the billing period for the nominated DSOC.

Notes:

1. The ENUC does not include the metering components of the tariff.

5.10 Anytime energy bi-directional (RT13 and RT14)

RT13 and RT14 consist of:

a. a fixed use of system charge (detailed in Table 8.1) which is payable each day;
b. a variable use of system charge calculated by multiplying the energy price (detailed in Table 8.1) by the quantity of electricity consumed (expressed in kWh); and
c. a fixed metering charge per revenue meter calculated in accordance with section 8.2.3 (detailed in Table 8.14 and Table 8.15) which is payable each day.

5.11 Time of use bi-directional (RT15 and RT16)

RT15 and RT16 consist of:

a. a fixed use of system charge (detailed in Table 8.1) which is payable each day;

b. an on-peak use of system variable charge calculated by multiplying the on-peak energy price (detailed in Table 8.1) by the quantity of on-peak electricity consumed (expressed in kWh);

c. an off-peak use of system variable charge calculated by multiplying the off-peak energy price (detailed in Table 8.1) by the quantity of off-peak electricity consumed (expressed in kWh); and

d. a fixed metering charge per revenue meter calculated in accordance with section 8.2.3 (detailed in Table 8.14 and Table 8.15) which is payable each day.

Notes:

1. The on and off-peak periods for these tariffs are defined in the following table (all times are WST):

Table 5.4: On and off-peak for RT15 and RT16

	Monday – Friday (includes public holidays)			Saturday – Sunday (excludes public holidays)
	Off-peak	**On-Peak**	**Off-Peak**	**Off-Peak**
RT15	12:00am – 7:00am	7:00am – 9:00pm	9:00pm – 12:00am	All times
RT16	12:00am – 8:00am	8:00am – 10:00pm	10:00pm – 12:00am	All times

5.12 Three part time of use energy (RT17 and RT18)

RT17 and RT18 consist of:

a. a fixed use of system charge (detailed in Table 8.1) which is payable each day;

b. an on-peak use of system variable charge calculated by multiplying the on-peak energy price (detailed in Table 8.1) by the quantity of on-peak electricity consumed at the connection point (expressed in kWh);

c. a shoulder use of system variable charge calculated by multiplying the shoulder energy price (detailed in Table 8.1) by the quantity of shoulder period electricity consumed at the connection point (expressed in kWh);

d. an off-peak use of system variable charge calculated by multiplying the off-peak energy price (detailed in Table 8.1) by the quantity of off-peak electricity consumed at the connection point (expressed in kWh); and

e. a fixed metering charge per revenue meter calculated in accordance with section 8.2.3 (detailed in Table 8.14 and Table 8.15) which is payable each day.

Notes:

1. The on-peak, shoulder and off-peak periods for these tariffs are defined in the table below (all times are WST).

Table 5.5: On and off-peak for RT17 and RT18

Monday – Friday (excludes public holidays)				Saturday – Sunday (includes public holidays)
Off-peak	**Shoulder**	**On-Peak**	**Off-Peak**	**Off-Peak**
12:00am – 12:00pm	12:00pm – 3:00pm	3:00pm – 9:00pm	9:00pm – 12:00am	All times

5.13 Three part time of use demand residential (RT19)

RT19 consist of:

a. a fixed use of system charge (detailed in Table 8.2) which is payable each day;

b. a demand based charge calculated by multiplying the demand charge (detailed in Table 8.2) by the maximum demand in a 30 minute period within the on-peak period defined below at the connection point (expressed in kW) measured over a billing period which is payable each day;

c. an on-peak use of system variable charge calculated by multiplying the on-peak energy price (detailed in Table 8.2 by the quantity of on-peak electricity consumed at the connection point (expressed in kWh);

d. a shoulder use of system variable charge calculated by multiplying the shoulder energy price (detailed in Table 8.2) by the quantity of shoulder period electricity consumed at the connection point (expressed in kWh);

e. an off-peak use of system variable charge calculated by multiplying the off-peak energy price (detailed in Table 8.2) by the quantity of off-peak electricity consumed at the connection point (expressed in kWh); and

f. a fixed metering charge per revenue meter calculated in accordance with section 8.2.3 (detailed in Table 8.14 and Table 8.15) which is payable each day.

Notes:

1. The on-peak, off-peak and shoulder periods for these tariffs are defined in the following table (all times are WST):

Table 5.6: On shoulder and off-peak for RT19

Monday – Friday (excludes public holidays)				Saturday – Sunday (includes public holidays)
Off-peak	**Shoulder**	**On-Peak**	**Off-Peak**	**Off-Peak**
12:00am – 12:00pm	12:00pm – 3:00pm	3:00pm – 9:00pm	9:00pm – 12:00am	All times

5.14 Three part time of use demand business (RT20)

RT20 consist of:

a. a fixed use of system charge (detailed in Table 8.2) which is payable each day;

b. a demand based charge calculated by multiplying the demand charge (detailed in Table 8.2) by the maximum demand in a 30 minute period within the on-peak period defined below at the connection point (expressed in kVA) measured over a billing period which is payable each day;

c. an on-peak use of system variable charge calculated by multiplying the on-peak energy price (detailed in Table 8.2) by the quantity of on-peak electricity consumed at the connection point (expressed in kWh);

d. a shoulder use of system variable charge calculated by multiplying the shoulder energy price (detailed in Table 8.2) by the quantity of shoulder period electricity consumed at the connection point (expressed in kWh);

e. an off-peak use of system variable charge calculated by multiplying the off-peak energy price (detailed in Table 8.2) by the quantity of off-peak electricity consumed at the connection point (expressed in kWh); and

f. a fixed metering charge per revenue meter calculated in accordance with section 8.2.3 (detailed in Table 8.14 and Table 8.15) which is payable each day.

Notes:

1. The on-peak, off-peak and shoulder periods for these tariffs are defined in the following table (all times are WST):

Table 5.7: On, shoulder and off-peak for RT20

Monday – Friday (excludes public holidays)				Saturday – Sunday (includes public holidays)
Off-peak	**Shoulder**	**On-Peak**	**Off-Peak**	**Off-Peak**
12:00am – 12:00pm	12:00pm – 3:00pm	3:00pm – 9:00pm	9:00pm – 12:00am	All times

5.15 Multi part time of use energy residential (RT21)

RT21 consist of:

a. a fixed use of system charge (detailed in Table 8.3) which is payable each day;

b. an on-peak use of system variable charge calculated by multiplying the on-peak energy price (detailed in Table 8.3) by the quantity of on-peak electricity consumed at the connection point (expressed in kWh);

c. a shoulder use of system variable charge calculated by multiplying the shoulder energy price (detailed in Table 8.3) by the quantity of shoulder period electricity consumed at the connection point (expressed in kWh);

d. an off-peak use of system variable charge calculated by multiplying the off-peak energy price (detailed in Table 8.3) by the quantity of off-peak electricity consumed at the connection point (expressed in kWh);

e. an overnight use of system variable charge calculated by multiplying the overnight energy price (detailed in Table 8.3) by the quantity of overnight electricity consumed at the connection point (expressed in kWh); and

f. a fixed metering charge per revenue meter calculated in accordance with section 8.2.3 (detailed in Table 8.14 and Table 8.15) which is payable each day.

Notes:

1. The on-peak, off-peak, shoulder and overnight periods for this tariff are defined in the following table (all times are WST):

Table 5.8: On, shoulder, overnight and off-peak for RT21

Monday – Friday (excludes public holidays)					Saturday – Sunday (includes public holidays)	
Off-Peak	**Shoulder**	**On-Peak**	**Off-Peak**	**Overnight**	**Off-Peak**	**Overnight**
4:00am – 7:00am	7:00am – 3:00pm	3:00pm – 9:00pm	9:00pm – 11:00pm	11:00pm – 4:00am	4:00am – 11:00pm	11:00pm – 4:00am

5.16 Multi part time of use energy business (RT22)

RT22 consist of:

a. a fixed use of system charge (detailed in Table 8.3) which is payable each day;

b. an on-peak use of system variable charge calculated by multiplying the on-peak energy price (detailed in Table 8.3) by the quantity of on-peak electricity consumed at the connection point (expressed in kWh);

c. a shoulder use of system variable charge calculated by multiplying the shoulder energy price (detailed in Table 8.3) by the quantity of shoulder period electricity consumed at the connection point (expressed in kWh);

d. an off-peak use of system variable charge calculated by multiplying the off-peak energy price (detailed in Table 8.3) by the quantity of off-peak electricity consumed at the connection point (expressed in kWh);

e. a super off-peak use of system variable charge calculated by multiplying the super off-peak energy price (detailed in Table 8.3) by the quantity of super off-peak electricity consumed at the connection point (expressed in kWh);

f. an overnight use of system variable charge calculated by multiplying the overnight energy price (detailed in Table 8.3) by the quantity of overnight electricity consumed at the connection point (expressed in kWh); and

g. a fixed metering charge per revenue meter calculated in accordance with section 8.2.3 (detailed in Table 8.14 and Table 8.15) which is payable each day.

Notes:

1. The on-peak, off-peak, shoulder, super off-peak and overnight periods for these tariffs are defined in the following table (all times are WST):

Table 5.9: On, shoulder, off, overnight and super off peak for RT22

Monday – Friday (excludes public holidays)					Saturday – Sunday (includes public holidays)	
Off-peak	**Shoulder**	**On-Peak**	**Off-Peak**	**Overnight**	**Off-Peak**	**Super Off-Peak**
4:00am – 7:00am	7:00am – 3:00pm	3:00pm – 9:00pm	9:00pm – 11:00pm	11:00pm – 4:00am	4:00am – 11:00pm	11:00pm – 4:00am

5.17 Super off-peak time of use energy (RT34 and RT35)

RT34 and 35 consists of:

a. a fixed use of system charge (detailed in Table 8.3) which is payable each day;

b. an on-peak use of system variable charge calculated by multiplying the on-peak energy price (detailed in Table 8.3) by the quantity of on-peak electricity consumed at the connection point (expressed in kWh);

c. a shoulder use of system variable charge calculated by multiplying the shoulder energy price (detailed in Table 8.3) by the quantity of shoulder period electricity consumed at the connection point (expressed in kWh);

d. an off-peak use of system variable charge calculated by multiplying the off-peak energy price (detailed in Table 8.3) by the quantity of off-peak electricity consumed at the connection point (expressed in kWh);

e. a super off-peak use of system variable charge calculated by multiplying the super off-peak energy price (detailed in Table 8.3) by the quantity of super off-peak electricity consumed at the connection point (expressed in kWh); and

f. a fixed metering charge per revenue meter calculated in accordance with section 8.2.3 (detailed in Table 8.14 and Table 8.15) which is payable each day.

Notes:

1. The on-peak, off-peak, shoulder, and super off-peak periods for these tariffs are defined in the following table (all times are WST):

Table 5.10: On, shoulder, off and super off peak for RT34 and RT35

Every day (Monday – Sunday (including public holidays))					
Off-Peak	**Shoulder**	**Super off-peak**	**On-Peak**	**Shoulder**	**Off-peak**
12:00am – 6:00am	6:00am – 9:00am	9:00am – 3:00pm	3:00pm – 9:00pm	9:00pm – 11:00pm	11:00pm – 12:00am

5.18 Super off-peak time of use demand business (RT36)

RT36 consists of:

a. a fixed use of system charge (detailed in Table 8.3) which is payable each day;

b. a demand based charge calculated by multiplying the demand charge (detailed in Table 8.3) by the maximum demand in a 30 minute period within the on-peak period defined below at the connection point (expressed in kVA) measured over a billing period which is payable each day;

c. an on-peak use of system variable charge calculated by multiplying the on-peak energy price (detailed in Table 8.3) by the quantity of on-peak electricity consumed at the connection point (expressed in kWh);

d. a shoulder use of system variable charge calculated by multiplying the shoulder energy price (detailed in Table 8.3) by the quantity of shoulder period electricity consumed at the connection point (expressed in kWh);

e. an off-peak use of system variable charge calculated by multiplying the off-peak energy price (detailed in Table 8.3) by the quantity of off-peak electricity consumed at the connection point (expressed in kWh);

f. a super off-peak use of system variable charge calculated by multiplying the super off-peak energy price (detailed in Table 8.3) by the quantity of super off-peak electricity consumed at the connection point (expressed in kWh); and

g. a fixed metering charge per revenue meter calculated in accordance with section 8.2.3 (detailed in Table 8.14and Table 8.15) which is payable each day.

Notes:

1. The on-peak, off-peak, shoulder, and super off-peak periods for these tariffs are defined in the following table (all times are WST):

Table 5.11: On, shoulder, off and super off peak for RT36

Every day (Monday – Sunday (including public holidays))					
Off-Peak	**Shoulder**	**Super off-peak**	**On-Peak**	**Shoulder**	**Off-peak**
12:00am – 6:00am	6:00am – 9:00am	9:00am – 3:00pm	3:00pm – 9:00pm	9:00pm – 11:00pm	11:00pm – 12:00am

5.19 Super off-peak time of use demand residential (RT37)

RT37 consists of:

a. a fixed use of system charge (detailed in Table 8.3) which is payable each day;

b. a demand based charge calculated by multiplying the demand charge (detailed in Table 8.3 by the maximum demand in a 30 minute period within the on-peak period defined below at the connection point (expressed in kW) measured over a billing period which is payable each day;

c. an on-peak use of system variable charge calculated by multiplying the on-peak energy price (detailed in Table 8.3) by the quantity of on-peak electricity consumed at the connection point (expressed in kWh);

d. a shoulder use of system variable charge calculated by multiplying the shoulder energy price (detailed in Table 8.3) by the quantity of shoulder period electricity consumed at the connection point (expressed in kWh);
e. an off-peak use of system variable charge calculated by multiplying the off-peak energy price (detailed in Table 8.3) by the quantity of off-peak electricity consumed at the connection point (expressed in kWh);
f. a super off-peak use of system variable charge calculated by multiplying the super off-peak energy price (detailed in Table 8.3) by the quantity of super off-peak electricity consumed at the connection point (expressed in kWh); and
g. a fixed metering charge per revenue meter calculated in accordance with section 8.2.3 (detailed in Table 8.14 and Table 8.15) which is payable each day.

Notes:

1. The on-peak, off-peak, shoulder, and super off-peak periods for these tariffs are defined in the following table (all times are WST):

Table 5.12: On, shoulder, off and super off peak for RT37

Every day (Monday – Sunday (including public holidays))					
Off-Peak	**Shoulder**	**Super off-peak**	**On-Peak**	**Shoulder**	**Off-peak**
12:00am – 6:00am	6:00am – 9:00am	9:00am – 3:00pm	3:00pm – 9:00pm	9:00pm – 11:00pm	11:00pm – 12:00am

6. Transmission tariffs

6.1 Transmission exit service (TRT1)

6.1.1 Tariff calculation

TRT1 consists of:

a. a user-specific charge that is to be an amount per day which reflects the costs to Western Power of providing the Connection Assets under an Access Contract, which may consist of capital and non-capital costs;

b. a variable use of system charge calculated by multiplying the applicable use of system price (detailed in Table 8.20) or where there is no applicable use of system price in Table 8.20 for the exit point, the price calculated by Western Power in accordance with section 6.2 of the Tariff Structure Statement by the contracted maximum demand (CMD) at the exit point (expressed in kW);

c. a variable common service charge calculated by multiplying the common service price (detailed in Table 8.22) by the CMD at the exit point (expressed in kW);

d. a variable control system service charge calculated by multiplying the control system service price (detailed in Table 8.24) by the CMD at the exit point (expressed in kW);

e. a fixed metering charge per revenue meter (detailed in Table 8.14) which is payable each day; and

f. excess network usage charges calculated in accordance with section 6.1.2 (if applicable).

6.1.2 Excess network usage charges

An additional charge applies to this tariff where the peak half-hourly demand exceeds the nominated CMD during the billing period of the load.

The excess network usage charge (ENUC) is calculated by applying a factor to the excess usage as follows:

$$ENUC = ENUM * (PD - CMD) * (UOS + CON + CS + CSS) / CMD$$

Where

ENUM	is the Excess network usage multiplier factor, which is defined in Table 8.25;
PD	is the peak half-hourly demand during the billing period of the load (expressed in kW);
CMD	is the nominated CMD for the billing period of the load (expressed in kW);
UOS	is the applicable variable use of system charge for the billing period for the nominated CMD;
CON	is the applicable user-specific charge for the billing period;
CS	is the applicable variable common service charge for the billing period for the nominated CMD;
CSS	is the applicable variable control system service charge for the billing period for the nominated CMD;

Notes:

1. The ENUC does not include the metering components of the tariff.
2. If the connection point is subject to the Capacity (Swap) Allocation Service, for the purposes of the ENUC calculation above the CMD is the total contracted capacity allocated to the connection point from time to time pursuant to the capacity allocation arrangement.

6.2 Transmission entry service (TRT2)

6.2.1 Tariff calculation

TRT2 consists of:

a. a user-specific charge that is to be an amount per day which reflects the costs to Western Power of providing the Connection Assets under an Access Contract, which may consist of capital and non-capital costs;

b. a variable use of system charge calculated by multiplying the applicable use of system price (detailed in Table 8.21) or where there is no applicable use of system price in Table 8.21 for the entry point, the price calculated by Western Power in accordance with section 6.2 of the TSS by the declared sent-out capacity (DSOC) at the entry point (expressed in kW);

c. a variable control system service charge calculated by multiplying the control system service price (detailed in Table 8.23 by the nameplate output of the generator at the entry point (expressed in kW);

d. a fixed metering charge per revenue meter (detailed in Table 8.14) which is payable each day; and

e. excess network usage charges calculated in accordance with section 6.2.2 (if applicable).

6.2.2 Excess network usage charges

An additional charge applies to this tariff where the peak half-hourly demand exceeds the nominated DSOC during the billing period except where Western Power deems the export of power in excess of DSOC was required for power system reliability and security purposes.

The excess network usage charge (ENUC) is calculated by applying a factor to the excess usage as follows:

$$ENUC = ENUM * (PD – DSOC) * (UOS + CON + CSS) / DSOC$$

Where:

ENUM	is the Excess network usage multiplier factor, which is defined in Table 8.25;
PD	is the peak half-hourly demand during the billing period (expressed in kW);
DSOC	is the nominated DSOC for the billing period (expressed in kW);
UOS	is the applicable variable use of system charge for the billing period for the nominated DSOC;
CON	is the applicable user-specific charge for the billing period; and
CSS	is the applicable variable control system service charge for the billing period.

Notes:

1. The ENUC does not include the metering components of the tariff.

6.3 Transmission storage service (TRT3)

TRT3 consists of:

a. a user-specific charge that is to be an amount per day which reflects the costs to Western Power of providing the Connection Assets under an Access Contract, which may consist of capital and non-capital costs;

b. a variable use of system charge calculated by multiplying the applicable use of system price (detailed in Table 8.21) or where there is no applicable use of system price in Table 8.21 for the entry point, the price calculated by Western Power in accordance with section 6.2 of the TSS by the declared sent-out capacity (DSOC) at the entry point (expressed in kW);

c. a variable control system service charge calculated by multiplying the control system service price (detailed in Table 8.23 by the nameplate output of the generator at the entry point (expressed in kW);

d. a fixed metering charge per revenue meter (detailed in Table 8.14) which is payable each day; and

e. excess network usage charges calculated in accordance with section 6.2.2 (if applicable).

6.3.1 Excess network usage charges

An additional charge applies to this tariff where the peak half-hourly demand exceeds the nominated DSOC during the billing period except where Western Power deems the export of power in excess of DSOC was required for power system reliability and security purposes.

The excess network usage charge (ENUC) is calculated by applying a factor to the excess usage as follows:

$$ENUC = ENUM * (PD - DSOC) * (UOS + CON + CSS) / DSOC$$

Where:

ENUM	is the Excess network usage multiplier factor, which is defined in Table 8.25;
PD	is the peak half-hourly demand during the billing period (expressed in kW);
DSOC	is the nominated DSOC for the billing period (expressed in kW);
UOS	is the applicable variable use of system charge for the billing period for the nominated DSOC;
CON	is the applicable user-specific charge for the billing period; and
CSS	is the applicable variable control system service charge for the billing period.

Notes:

1. The ENUC does not include the metering components of the tariff.

7. Other tariffs

7.1 Entry Service Facilitating a Distributed Generation or Other Non-Network Solution (RT23)

7.1.1 Tariff calculation

RT23 consists of:

a. the reference tariff (RT11) applicable to the entry reference service B1 upon which the B3 – Entry Service Facilitating a Distributed Generation or Other Non-Network Solution is provided; less

b. the discount that applies to the connection point as set out in clause 7.1.2 below.

7.1.2 Discount

Western Power will provide a discount to RT11 in circumstances where the service allows for facilities and equipment connected behind the connection point (including distributed generating plant and other non-network solutions) that results in Western Power's capital-related costs or non-capital costs reducing as a result of the entry point for the distributed generating plant or other non-network solution being located in that particular part of the covered network.

In situations where a user connects facilities and equipment (including distributed generating plant) to the Western Power Network and has applied and been assessed as resulting in Western Power's capital-related costs or non-capital costs reducing as a result of the entry point for the distributed generating plant or other non-network solution being located in that particular part of the covered network, the discount to be applied is an annualised discount amount (which can be no greater than the annual charge), calculated as the present value of FCp less FCn over a period of Y years using discount rate W.

Where:

FCp	is the present value of the Western Power committed forecast capital-related costs and non-capital costs that would be incurred over Y years if the facilities and equipment (including distributed generating plant) were not to connect to the Western Power Network.
FCn	is the present value of Western Power's forecast capital-related costs and non-capital costs over Y years that are anticipated to be incurred if the facilities and equipment (including distributed generating plant) were to connect to the Western Power Network.
Y	is the period over which the present value assessment is to occur which is 15 years unless otherwise agreed between Western Power and the user.
W	is the Weighted Average Cost of Capital as set out in section 5.4 of the Access Arrangement that applies in the pricing year.

7.2 Bi-directional Service Facilitating a Distributed Generation or Other Non-Network Solution (RT24)

7.2.1 Tariff calculation

RT24 consists of:

a. the reference tariff (RT5 - RT8, RT13 - RT22 and RT34 - 37) applicable to the bi-directional reference service identified from C1 to C14 and C16 to C19 upon which the C15 - Bi-directional Service Facilitating a Distributed Generation or Other Non-Network Solution is provided; less

b. the discount that applies to the connection point as set out in clause 7.2.2 below.

7.2.2 Discount

Western Power will provide a discount to (RT5 - RT8, RT13 - RT22 and RT34 - 37) in circumstances where the service allows for facilities and equipment connected behind the connection point (including distributed generating plant and other non-network solutions) that results in Western Power's capital-related costs or non-capital costs reducing as a result of the entry point for the distributed generating plant or other non-network solution being located in that particular part of the covered network.

In situations where a user connects facilities and equipment (including distributed generating plant) to the Western Power Network and has applied and been assessed as resulting in Western Power's capital-related costs or non-capital costs reducing as a result of the entry point for the distributed generating plant or other non-network solution being located in that particular part of the covered network, the discount to be applied is an annualised discount amount (which can be no greater than the annual charge), calculated as the present value of FCp less FCn over a period of Y years using discount rate W.

Where:

FCp	is the present value of the Western Power forecast capital-related costs and non-capital costs that would be incurred over Y years if the facilities and equipment (including distributed generating plant) were not to connect to the Western Power Network.
FCn	is the present value of Western Power's forecast capital-related costs and non-capital costs over Y years that are anticipated to be incurred if the facilities and equipment (including distributed generating plant) were to connect to the Western Power Network.
Y	is the period over which the present value assessment is to occur which is 15 years unless otherwise agreed between Western Power and the user.
W	is the Weighted Average Cost of Capital as set out in section 5.4 of the Access Arrangement that applies in the pricing year.

7.3 Supply abolishment service (RT25)

7.3.1 Tariff calculation

RT25 consists of a charge per connection point supply abolishment (detailed in Table 8.26).

7.4 Remote load/inverter control service (RT26)

7.4.1 Tariff calculation

RT26 consists of a charge per request to remotely control load (detailed in Table 9.1).

7.5 Remote de-energise service (RT28)

7.5.1 Tariff calculation

RT28 consists of a charge per request for de-energisation (detailed in Table 8.27).

7.6 Remote de-energise service (RT29)

7.6.1 Tariff calculation

RT29 consists of a charge per request for re-energisation (detailed in Table 8.27).

7.7 LED replacement service (RT30)

7.7.1 Tariff calculation

RT30 consists of a user-specific charge that is to be an amount which reflects the costs to Western Power of replacing the existing streetlight with the LED streetlight replacement requested by the user which may consist of capital and non-capital costs.

7.8 Site Visit to Support Remote Re-energise Service (RT31)

RT31 consists of a charge per request for a site visit to support remote re-energisation of a site (detailed in Table 8.28).

7.9 Manual De-energise Service (RT32)

RT32 consists of a charge per request for manual de-energisation of a site (detailed in Table 8.28).

7.10 Manual Re-energise Service (RT33)

RT33 consists of a charge per request for manual re-energisation of a site (detailed in Table 8.28).

7.11 Distribution storage service (RT38 and RT39)

7.11.1 Tariff calculation

RT38 and RT39 consists of:

a. a fixed use of system charge that reflects the costs of providing connection assets (detailed in Table 8.5) which is payable each day;

b. for nett consumption from the Western Power network:

i. an on-peak use of system variable charge calculated by multiplying the on-peak energy price (detailed in Table 8.4) by the quantity of on-peak electricity consumed at the connection point (expressed in kWh);

ii. a shoulder use of system variable charge calculated by multiplying the shoulder energy price (detailed in Table 8.4) by the quantity of shoulder period electricity consumed at the connection point (expressed in kWh);

iii. an off-peak use of system variable charge calculated by multiplying the off-peak energy price (detailed in Table 8.4) by the quantity of off-peak electricity consumed at the connection point (expressed in kWh);

iv. a super off-peak use of system variable charge calculated by multiplying the super off-peak energy price (detailed in Table 8.4) by the quantity of super off-peak electricity consumed at the connection point (expressed in kWh);

c. for nett exports to the Western Power network:

i. an on-peak use of system variable charge calculated by multiplying the on-peak energy price (detailed in Table 8.4) by the quantity of on-peak electricity exported at the connection point (expressed in kWh);

ii. a shoulder use of system variable charge calculated by multiplying the shoulder energy price (detailed in Table 8.4) by the quantity of shoulder period electricity exported at the connection point (expressed in kWh);

iii. an off-peak use of system variable charge calculated by multiplying the off-peak energy price (detailed in Table 8.4) by the quantity of off-peak electricity exported at the connection point (expressed in kWh);

iv. a stepped super off-peak use of system variable charge calculated by multiplying:

A. the first 3kWh of super off-peak electricity exported (expressed in kWh) at the connection point by the super off-peak energy price (detailed in Table 8.4) measured over a billing period which is payable each day; and

B. the quantity of super off-peak electricity in excess of 3kWh exported (expressed in kWh) at the connection point by the super off-peak energy price (detailed in Table 8.4) measured over a billing period which is payable each day.

d. a fixed metering charge per revenue meter calculated in accordance with section 8.2.3 (detailed in Table 8.14 and Table 8.15) which is payable each day.

Notes:

1. The on-peak, off-peak, shoulder, and super off-peak periods for these tariffs are defined in the following table (all times are WST):

Table 7.1: On, shoulder, off and super off peak for RT38 and RT39

Every day (Monday – Sunday (including public holidays))					
Off-Peak	**Shoulder**	**Super off-peak**	**On-Peak**	**Shoulder**	**Off-peak**
12:00am – 6:00am	6:00am – 9:00am	9:00am – 3:00pm	3:00pm – 9:00pm	9:00pm – 11:00pm	11:00pm – 12:00am

7.12 EV charging service (RT40 and RT41)

7.12.1 Tariff calculation

RT40 and RT41 consists of:

a. a fixed use of system charge that reflects the costs of providing connection assets (detailed in Table 8.6) which is payable each day;

b. an on-peak use of system variable charge that varies with network utilisation defined below which is calculated by multiplying the on-peak energy price relevant to the network utilisation percentage band (detailed in Table 8.6) by the quantity of on-peak electricity consumed at the connection point (expressed in kWh);

c. a shoulder use of system variable charge that varies with network utilisation defined below which is calculated by multiplying the shoulder energy price relevant to the network utilisation percentage band (detailed in Table 8.6) by the quantity of shoulder electricity consumed at the connection point (expressed in kWh);

d. an off-peak use of system variable charge that varies with network utilisation defined below which is calculated by multiplying the off-peak energy price relevant to the network utilisation percentage band (detailed in Table 8.6) by the quantity of off-peak electricity consumed at the connection point (expressed in kWh);

e. a super off-peak use of system variable charge that varies with network utilisation defined below which is calculated by multiplying the super off-peak energy price relevant to the network utilisation percentage band (detailed in Table 8.6) by the quantity of super off-peak electricity consumed at the connection point (expressed in kWh);

f. a demand-based charge that varies with network utilisation defined below calculated by multiplying the demand charge relevant to the network utilisation percentage band (detailed in Table 8.6) by the maximum demand in a 30-minute period within the on-peak period defined below at the connection point (expressed in kVA) measured over a billing period which is payable each day;

g. a fixed metering charge per revenue meter calculated in accordance with section 8.2.3 (detailed in Table 8.14 and Table 8.15) which is payable each day.

Notes:

1. The on-peak, shoulder, super off-peak and off-peak periods for these tariffs are defined in the following table (all times are WST):

Table 7.2: On, shoulder, off and super off peak for RT40 and RT41

Every day (Monday – Sunday (including public holidays))					
Off-peak	**Shoulder**	**Super off-peak**	**On-peak**	**Shoulder**	**Off-peak**
12:00am – 6:00am	6:00am – 9:00am	9:00am – 3:00pm	3:00pm – 9:00pm	9:00pm – 11:00pm	11:00pm – 12:00am

7.12.2 Calculation of network utilisation

Western Power has designed a measure of network utilisation to provide strong support to EV charging stations during this access arrangement. The calculation of network utilisation:

- Is based on demand in the twelve 30-minute intervals between 3pm and 9pm (being the on-peak period); and
- excludes any 30-minute interval where demand is less than 10kW.

The formula for calculation of the network utilisation for this tariff is:

$$\frac{30\ minute\ intervals\ with\ demand\ above\ 10kW\ between\ 3pm\ and\ 9pm}{30\ minute\ intervals\ in\ a\ billing\ period}$$

The resultant percentage from the above calculation is used to assign the site to the relevant network utilisation percentage band as set out below that will set out the network charges applicable to the site.

7.12.3 Defining the network utilisation percentage bands

For the purposes of this tariff, Western Power has defined three network utilisation percentage bands that set out the applicable use of system variable charges and demand-based charge that will apply to the connection point as defined in the following table:

Table 7.3: Network utilisation bands

Network utilisation percentage bands	
1	≥ 0% and < 15%
2	≥ 15% and < 30%
3	≥ 30%

8. Price tables

The tables in the following sections must be used in conjunction with the details in the sections above.

Table 8.11, Table 8.20 and Table 8.21 include a Transmission Node Identity (TNI) to uniquely identify zone substations.

All prices quoted in this Price List are **GST exclusive**.

8.1 Prices for energy-based tariffs on the distribution network

8.1.1 Use of system prices

The prices in the following tables are applicable for reference tariffs **RT1, RT2, RT3, RT4, RT9, RT10, RT13, RT14, RT15, RT16, RT 17, RT18, RT19, RT20, RT21, RT22, RT34, RT35, RT36, RT37, RT38, RT39, RT40 and RT41**.

Table 8.1: Reference tariffs prices for RT1, RT2, RT3, RT4, RT9, RT10, RT13, RT14, RT15, RT16, RT17 and RT18

Bundled tariff	Fixed Price c/day	Energy Rates			
		Anytime c/kWh	On-Peak c/kWh	Shoulder c/kWh	Off-Peak c/kWh
Reference tariff 1 - RT1	108.680	9.336	-	-	-
Reference tariff 2 - RT2	206.079	12.826	-	-	-
Reference tariff 3 - RT3	108.680	-	19.616	-	4.835
Reference tariff 4 - RT4	377.268	-	21.141	-	5.447
Reference tariff 9 – RT9	7.953	5.443	-	-	-
Reference tariff 10 – RT10	63.809	5.226	-	-	-
Reference tariff 13 - RT13	108.680	9.336	-	-	-
Reference tariff 14 - RT14	206.079	12.826	-	-	-
Reference tariff 15 - RT15	108.680	-	19.616	-	4.835
Reference tariff 16 - RT16	377.268	-	21.141	-	5.447
Reference tariff 17 - RT17	108.680	-	15.023	8.602	6.196
Reference tariff 18 - RT18	214.818	-	22.843	14.550	10.316

Table 8.2: Reference tariffs for RT19 and RT20

Bundled tariff	Fixed Price	Demand	Energy Rates		
	c/day	c/kW or kVA/day	On-Peak c/kWh	Shoulder c/kWh	Off-Peak c/kWh
Reference tariff 19 – RT19	108.680	6.552	12.987	7.582	5.141
Reference tariff 20 - RT20	258.703	7.831	21.582	12.621	9.150

Table 8.3: Reference tariffs for RT21, RT22, RT34, RT35, RT36 and RT37

Bundled tariff	Fixed Price	Demand	Energy Rates				
	c/day	c/kW or KVA/day	On-Peak c/kWh	Shoulder c/kWh	Off-Peak c/kWh	Overnight c/kWh	Super Off-Peak c/kWh
Reference tariff 21 – RT21	108.680	-	14.967	8.412	5.941	7.069	-
Reference tariff 22 – RT22	206.079	-	23.611	12.713	8.861	10.543	10.543
Reference tariff 34 – RT34	206.079	-	20.989	10.495	8.073	-	5.342
Reference tariff 35 – RT35	108.680	-	16.350	8.175	6.288	-	0.106
Reference tariff 36 – RT36	342.134	7.376	19.047	9.524	7.326	-	5.342
Reference tariff 37 – RT37	108.680	6.132	13.689	6.845	5.265	-	0.106

Table 8.4: Reference tariffs for RT38 and RT39

Bundled tariff	Fixed Price	Energy Rates (network to storage - charging)				
	c/day	Off-Peak c/kWh	Shoulder c/kWh	Super Off-Peak c/kWh		On-Peak c/kWh
Reference tariff 38 – RT38	Varies with capacity see Table 8.5 below	0.109	10.559	0.109		21.129
		Energy Rates (storage to network – discharging)				
		Off-Peak c/kWh	Shoulder c/kWh	Super Off-peak 0-3 kWh c/kWh	Super Off-Peak > 3 kWh c/kWh	On-Peak c/kWh
		0.109	0.109	10.559	21.129	0.109
Bundled tariff	**Fixed Price**	**Energy Rates (network to storage - charging)**				
	c/day	**Off-Peak c/kWh**	**Shoulder c/kWh**	**Super Off-Peak c/kWh**		**On-Peak c/kWh**
Reference tariff 39 – RT39	Varies with capacity see Table 8.5 below	0.109	10.559	0.109		21.129
		Energy Rates (storage to network - discharging)				
		Off-Peak c/kWh	Shoulder c/kWh	Super Off-peak 0-3 kWh c/kWh	Super Off-Peak > 3 kWh c/kWh	On-Peak c/kWh
		0.109	0.109	10.559	21.129	0.109

Table 8.5: Fixed Price for Reference tariffs for RT38 and RT39

Capacity of storage works kVA	Fixed Price c/day
≥ 0 and < 100	382.550
≥100 and < 1,000	765.100
≥1,000 and < 3,000	1,639.500
≥ 3,000	1,639.500

Table 8.6: Reference tariffs for RT40 and RT41

Bundled tariff	Utilisation %	Fixed Price c/day	Energy Rates				
			Off-Peak c/kWh	Shoulder c/kWh	On-Peak c/kWh	Super Off-peak c/kWh	Demand On-peak c/kVA/day
Reference tariff 40 – RT40	≥0 & <15	382.550	0.000	6.726	17.488	8.744	4.591
	≥15 & <30	382.550	16.395	3.363	8.744	4.372	3.279
	≥30	382.550	32.790	1.682	4.372	2.186	1.640
Reference tariff 41 – RT41	≥0 & <15	382.550	0.000	6.726	17.488	8.744	4.591
	≥15 & <30	382.550	16.395	3.363	8.744	4.372	3.279
	≥30	382.550	32.790	1.682	4.372	2.186	1.640

8.1.2 Streetlight asset prices

The prices in the following tables are applicable for reference tariff **RT9**.

Table 8.7: Current light types

Light specification	Daily Charge (No contribution)	Daily Charge (Full upfront contribution)
	c/day	c/day
42 CFL DECORATIVE	30.558	N/A
42 CFL STANDARD	30.558	N/A
150 HPS STANDARD	34.298	N/A
14 LED DECORATIVE	34.461	11.510
16 LED DECORATIVE	34.461	11.510
18 LED DECORATIVE	34.461	11.510
20 LED DECORATIVE	34.461	11.510
22 LED DECORATIVE	34.461	11.510
28 LED DECORATIVE	34.461	11.510
30 LED DECORATIVE	34.461	11.510
43 LED DECORATIVE	34.461	11.510
53 LED DECORATIVE	34.461	11.510
80 LED DECORATIVE	34.461	11.510
100 LED DECORATIVE	38.708	11.510

150 LED DECORATIVE	38.708	11.510
170 LED DECORATIVE	38.708	11.510
16 LED STANDARD	16.119	11.510
17 LED STANDARD	16.119	11.510
18 LED STANDARD	16.119	11.510
20 LED STANDARD	16.119	11.510
28 LED STANDARD	16.119	11.510
36 LED STANDARD	16.119	11.510
42 LED STANDARD	16.248	11.510
43 LED STANDARD	16.248	11.510
53 LED STANDARD	16.248	11.510
70 LED STANDARD	16.092	11.510
80 LED STANDARD	16.092	11.510
135 LED STANDARD	17.655	11.510
140 LED STANDARD	17.655	11.510
165 LED STANDARD	17.655	11.510
170 LED STANDARD	17.655	11.510
Other wattages STANDARD	16.119	11.510
Other wattages DECORATIVE	34.461	11.510

Table 8.8: Obsolete light types

Light specification	Daily Charge (No contribution)
	c/day
70 HPS STANDARD	26.074
80 HPS STANDARD	26.834
125 HPS STANDARD	35.299
250 HPS STANDARD	34.298
400 HPS STANDARD	35.299
40 FLU STANDARD	19.410
100 INC STANDARD	19.410
17 LED DECORATIVE	32.820
34 LED DECORATIVE	32.820

36 LED DECORATIVE	32.820
42 LED DECORATIVE	30.005
155 LED DECORATIVE	38.708
22 LED STANDARD	16.119
27 LED STANDARD	16.119
68 LED STANDARD	16.092
155 LED STANDARD	17.655
160 LED STANDARD	17.655
70 MH STANDARD	53.014
80 MH STANDARD	26.125
150 MH STANDARD	61.249
250 MH STANDARD	61.249
42 MV STANDARD	19.410
50 MV STANDARD	19.410
70 MV STANDARD	26.125
80 MV STANDARD	26.125
125 MV STANDARD	32.480
150 MV STANDARD	32.480
250 MV STANDARD	42.369
400 MV STANDARD	44.486

8.2 Prices for demand-based tariffs on the distribution network (RT5 to RT8 and RT11[7])

8.2.1 Demand charges

The prices in the following table are applicable for reference tariff **RT5**.

Table 8.9: Prices for reference tariff RT5

Demand (kVA) (Lower to upper threshold)	Bundled tariff	
	Fixed c/day	Demand (in excess of lower threshold) c/kVA/day
0 to 300	206.900	99.072

[7] Note that some components of RT11 are in section 8.3.

Demand (kVA) (Lower to upper threshold)	Bundled tariff	
	Fixed c/day	Demand (in excess of lower threshold) c/kVA/day
300 to 1,000	29,721.600	71.970
1,000 to 1,500	80,100.600	34.487

The prices in the following table are applicable for reference tariff **RT6**.

Table 8.10: Prices for reference tariff RT6

Demand (kVA) (Lower to upper threshold)	Bundled tariff	
	Fixed c/day	Demand (in excess of lower threshold) c/kVA/day
0 to 300	1,193.968	103.213
300 to 1,000	30,963.900	79.520
1,000 to 1,500	86,627.900	41.479

The prices in the following table are applicable for reference tariffs **RT7** and **RT8**.

Table 8.11: Prices for reference tariffs RT7 and RT8

Zone substation	TNI	Pricing zone	Bundled		
			Fixed charge for first 1000 kVA (c per day)	Demand charge for 1000<kVA<7000 (c/kVA/day)	Demand Charge for kVA > 7000 (c/kVA/day)
Cook Street	WCKT	CBD	59,760.468	34.505	38.113
Forrest Avenue	WFRT	CBD	59,760.468	34.505	38.113
Hay Street	WHAY	CBD	59,760.468	34.505	38.113
Milligan Street	WMIL	CBD	59,760.468	34.505	38.113
Wellington Street	WWNT	CBD	59,760.468	34.505	38.113
Black Flag	WBKF	Mining	59,760.468	51.277	52.489
Boulder	WBLD	Mining	59,760.468	47.802	49.511
Bounty	WBNY	Mining	59,760.468	85.475	81.801
West Kalgoorlie	WWKT	Mining	59,760.468	43.344	45.690
Albany	WALB	Mixed	59,760.468	57.125	57.502

Zone substation	TNI	Pricing zone	Bundled		
			Fixed charge for first 1000 kVA (c per day)	Demand charge for 1000<kVA<7000 (c/kVA/day)	Demand Charge for kVA > 7000 (c/kVA/day)
Boddington	WBOD	Mixed	59,760.468	34.847	38.406
Bunbury Harbour	WBUH	Mixed	59,760.468	34.380	38.006
Busselton	WBSN	Mixed	59,760.468	43.737	46.026
Byford	WBYF	Mixed	59,760.468	35.932	39.336
Capel	WCAP	Mixed	59,760.468	40.386	43.154
Chapman	WCPN	Mixed	59,760.468	49.328	50.818
Darlington	WDTN	Mixed	59,760.468	38.546	41.577
Durlacher Street	WDUR	Mixed	59,760.468	45.863	47.848
Eneabba	WENB	Mixed	59,760.468	43.918	46.181
Geraldton	WGTN	Mixed	59,760.468	45.863	47.848
Marriott Road	WMRR	Mixed	59,760.468	33.670	37.397
Muchea	WMUC	Mixed	59,760.468	38.343	41.403
Northam	WNOR	Mixed	59,760.468	46.999	48.822
Picton	WPIC	Mixed	59,760.468	36.042	39.430
Rangeway	WRAN	Mixed	59,760.468	47.987	49.669
Sawyers Valley	WSVY	Mixed	59,760.468	44.183	46.409
Yanchep	WYCP	Mixed	59,760.468	38.258	41.330
Yilgarn	WYLN	Mixed	59,760.468	54.255	55.041
Baandee	WBDE	Rural	59,760.468	50.999	52.251
Beenup	WBNP	Rural	59,760.468	54.447	55.206
Bridgetown	WBTN	Rural	59,760.468	35.229	38.734
Carrabin	WCAR	Rural	59,760.468	55.510	56.117
Cataby	WKMC	Rural	59,760.468	36.257	39.615
Collie	WCOE	Rural	59,760.468	40.705	43.427
Coolup	WCLP	Rural	59,760.468	45.204	47.283
Cunderdin	WCUN	Rural	59,760.468	47.364	49.135
Katanning	WKAT	Rural	59,760.468	43.675	45.973

Zone substation	TNI	Pricing zone	Bundled		
			Fixed charge for first 1000 kVA (c per day)	Demand charge for 1000<kVA<7000 (c/kVA/day)	Demand Charge for kVA > 7000 (c/kVA/day)
Kellerberrin	WKEL	Rural	59,760.468	49.798	51.221
Kojonup	WKOJ	Rural	59,760.468	31.893	35.874
Kondinin	WKDN	Rural	59,760.468	33.948	37.635
Manjimup	WMJP	Rural	59,760.468	34.988	38.527
Margaret River	WMRV	Rural	59,760.468	43.812	46.091
Merredin	WMER	Rural	59,760.468	45.651	47.667
Moora	WMOR	Rural	59,760.468	35.303	38.797
Mount Barker	WMBR	Rural	59,760.468	45.533	47.565
Narrogin	WNGN	Rural	59,760.468	50.705	51.998
Pinjarra	WPNJ	Rural	59,760.468	26.622	31.356
Regans	WRGN	Rural	59,760.468	36.257	39.615
Three Springs	WTSG	Rural	59,760.468	35.211	38.718
Wagerup	WWGP	Rural	59,760.468	25.612	30.490
Wagin	WWAG	Rural	59,760.468	44.215	46.436
Wundowie	WWUN	Rural	59,760.468	39.278	42.204
Yerbillon	WYER	Rural	59,760.468	54.215	55.007
Amherst	WAMT	Urban	59,760.468	25.671	30.541
Arkana	WARK	Urban	59,760.468	25.671	30.541
Australian Paper Mills	WAPM	Urban	59,760.468	25.671	30.541
Balcatta	WBCT	Urban	59,760.468	25.671	30.541
Beechboro	WBCH	Urban	59,760.468	25.671	30.541
Belmont	WBEL	Urban	59,760.468	25.671	30.541
Bentley	WBTY	Urban	59,760.468	25.671	30.541
Bibra Lake	WBIB	Urban	59,760.468	25.671	30.541
British Petroleum	WBPM	Urban	59,760.468	25.671	30.541
Canning Vale	WCVE	Urban	59,760.468	25.671	30.541
Clarence Street	WCLN	Urban	59,760.468	25.671	30.541

Zone substation	TNI	Pricing zone	Bundled		
			Fixed charge for first 1000 kVA (c per day)	Demand charge for 1000<kVA<7000 (c/kVA/day)	Demand Charge for kVA > 7000 (c/kVA/day)
Clarkson	WCKN	Urban	59,760.468	25.671	30.541
Cockburn Cement	WCCT	Urban	59,760.468	25.671	30.541
Collier	WCOL	Urban	59,760.468	25.671	30.541
Cottesloe	WCTE	Urban	59,760.468	25.671	30.541
Edmund Street	WEDD	Urban	59,760.468	25.671	30.541
Forrestfield	WFFD	Urban	59,760.468	25.671	30.541
Gosnells	WGNL	Urban	59,760.468	25.671	30.541
Hadfields	WHFS	Urban	59,760.468	25.671	30.541
Hazelmere	WHZM	Urban	59,760.468	25.671	30.541
Henley Brook	WHBK	Urban	59,760.468	25.671	30.541
Herdsman Parade	WHEP	Urban	59,760.468	25.671	30.541
Joel Terrace	WJTE	Urban	59,760.468	25.671	30.541
Joondalup	WJDP	Urban	59,760.468	25.671	30.541
Kalamunda	WKDA	Urban	59,760.468	25.671	30.541
Kambalda	WKBA	Urban	59,760.468	43.737	46.026
Kewdale	WKDL	Urban	59,760.468	25.671	30.541
Landsdale	WLDE	Urban	59,760.468	25.671	30.541
Maddington	WMDN	Urban	59,760.468	25.671	30.541
Malaga	WMLG	Urban	59,760.468	25.671	30.541
Mandurah	WMHA	Urban	59,760.468	25.671	30.541
Manning Street	WMAG	Urban	59,760.468	25.671	30.541
Mason Road	WMSR	Urban	59,760.468	25.671	30.541
Meadow Springs	WMSS	Urban	59,760.468	25.671	30.541
Medical Centre	WMCR	Urban	59,760.468	25.671	30.541
Medina	WMED	Urban	59,760.468	25.671	30.541
Midland Junction	WMJX	Urban	59,760.468	25.671	30.541
Morley	WMOY	Urban	59,760.468	25.671	30.541

Zone substation	TNI	Pricing zone	Bundled		
			Fixed charge for first 1000 kVA (c per day)	Demand charge for 1000<kVA<7000 (c/kVA/day)	Demand Charge for kVA > 7000 (c/kVA/day)
Mullaloo	WMUL	Urban	59,760.468	25.671	30.541
Mundaring Weir	WMWR	Urban	59,760.468	25.671	30.541
Munday	WMDY	Urban	59,760.468	25.671	30.541
Murdoch	WMUR	Urban	59,760.468	25.671	30.541
Myaree	WMYR	Urban	59,760.468	25.671	30.541
Nedlands	WNED	Urban	59,760.468	25.671	30.541
North Beach	WNBH	Urban	59,760.468	25.671	30.541
North Fremantle	WNFL	Urban	59,760.468	25.671	30.541
North Perth	WNPH	Urban	59,760.468	25.671	30.541
O'Connor	WOCN	Urban	59,760.468	25.671	30.541
Osborne Park	WOPK	Urban	59,760.468	25.671	30.541
Padbury	WPBY	Urban	59,760.468	25.671	30.541
Piccadilly	WPCY	Urban	59,760.468	41.302	43.939
Riverton	WRTN	Urban	59,760.468	25.671	30.541
Rivervale	WRVE	Urban	59,760.468	25.671	30.541
Rockingham	WROH	Urban	59,760.468	25.671	30.541
Shenton Park (Old)	WSPA	Urban	59,760.468	25.671	30.541
Shenton Park (New AA5)	WSPK	Urban	59,760.468	25.671	30.541
Sth Ftle Power Station	WSFT	Urban	59,760.468	25.671	30.541
Southern River	WSNR	Urban	59,760.468	25.671	30.541
Southern Cross	WSNX	Mixed	59,760.468	54.255	55.041
Tate Street	WTTS	Urban	59,760.468	25.671	30.541
University	WUNI	Urban	59,760.468	25.671	30.541
Victoria Park	WVPA	Urban	59,760.468	25.671	30.541
Waikiki	WWAI	Urban	59,760.468	25.671	30.541
Wangara	WWGA	Urban	59,760.468	25.671	30.541

Zone substation	TNI	Pricing zone	Bundled		
			Fixed charge for first 1000 kVA (c per day)	Demand charge for 1000<kVA<7000 (c/kVA/day)	Demand Charge for kVA > 7000 (c/kVA/day)
Wanneroo	WWNO	Urban	59,760.468	25.671	30.541
Welshpool	WWEL	Urban	59,760.468	25.671	30.541
Wembley Downs	WWDN	Urban	59,760.468	25.671	30.541
Willetton	WWLN	Urban	59,760.468	25.671	30.541
Yokine	WYKE	Urban	59,760.468	25.671	30.541

8.2.2 Demand length charges

The prices in the following table are applicable for reference tariffs **RT5, RT6, RT7, RT8** and **RT11** and the CMD/DSOC is between 1,000 and 7,000 kVA.

Table 8.12: Reference for tariffs RT5, RT6, RT7, RT8 and RT11

Pricing zone	Demand-Length Charge	
	For kVA >1000 and first 10 km length (c/kVA.km/day)	For kVA >1000 and length in excess of 10 km (c/kVA.km/day)
CBD	0.000	0.000
Urban	1.956	1.383
Mining	0.419	0.293
Mixed	0.913	0.631
Rural	0.568	0.396

The prices in the following table are applicable for reference tariffs **RT7, RT8** and **RT11** and the CMD/DSOC is at least 7,000 kVA.

Table 8.13: Reference tariffs RT7, RT8 and RT11

Pricing zone	Demand-Length Charge	
	For first 10 km length (c/kVA.km/day)	For length in excess of 10 km (c/kVA.km/day)
CBD	0.000	0.000
Urban	1.676	1.176
Mining	0.362	0.252

Mixed	0.786	0.545
Rural	0.493	0.339

8.2.3 Metering prices

The prices in the following table are applicable for all reference tariffs (excluding RT9, RT10, RT25, RT26, and RT28 to RT33).

The total metering price payable is the sum of the applicable charge in Table 8.14, which is based on the reference tariff of the connection point and the charge in Table 8.15, which is based on the metering reference service applicable to the connection point, or as selected by the retailer. The applicable metering reference service for each reference service is defined in Appendix E, table E.1.2[8].

Note that for billing purposes, Western Power will calculate the total metering charge per connection point (a sum of the relevant charge in Table 8.14 and Table 8.15) as a single daily charge.

For the purposes of the Metering Model Service Level Agreement, the charges in Table 8.15 (M1 – M15 and M17 – M20) are considered to be the incremental fees involved in providing the additional metering services.

Table 8.14: Metering prices[9]

Reference Tariff	c/revenue meter/day
RT1	9.510
RT2	10.037
RT3	9.888
RT4	15.597
RT5 – RT8	17.195
RT11	17.195
RT13	9.510
RT14	10.037
RT15	9.888
RT16	15.597
RT17	17.195
RT18	17.195
RT19	17.195
RT20	17.195
RT21	17.195

8 https://www.erawa.com.au/cproot/20419/2/ERA-Approved---Appendix-E---Reference-Services.pdf

9 Additional charges will apply if the user has selected a non-standard metering service for the relevant exit, entry or bi-directional service. The charge will reflect Western Power's incremental costs of providing the additional metering services and may consist of capital and non-capital costs.

Reference Tariff	c/revenue meter/day
RT22	17.195
RT34	10.037
RT35	9.510
RT36	10.037
RT37	9.510
RT38	17.195
RT39	17.195
RT40	17.195
RT41	17.195
TRT1, TRT2 and TRT3	1,014.995

Table 8.15: Metering reference service prices

Metering Reference Service	c/revenue meter/day
M1	2.891
M2	2.891
M3	32.998
M4	65.998
M5	17.633
M6	17.633
M7 - SIM	152.860
M7 - AMI	2.891
M8	2.891
M9	2.891
M10	32.998
M11	65.998
M12	17.633
M13	17.633
M14 - SIM	152.860
M14 - AMI	2.891
M15	-
M17	793.353

Metering Reference Service	c/revenue meter/day
M18	77.968
M19	793.353
M20	77.968

Table 8.16: Metering reference service prices

Metering Reference Service	Charge per site visit ($)
M16	24.650

8.2.4 Administration charges

The prices in the following table are applicable for reference tariffs **RT7** and **RT8**.

Table 8.17: Administration charges for RT7 and RT8

CMD	Price (c/day)
<7,000 kVA	6,071.132
>=7,000 kVA	10,573.560

8.2.5 LV prices

The prices in the following table are applicable for reference tariff **RT8**.

Table 8.18: LV prices RT8

Bundled Tariff	Fixed Price	Demand
	c/day	c/kVA
RT8	1,264.411	12.328

8.2.6 Connection price

The prices in the following table are applicable for reference tariff **RT11**.

Table 8.19: Connection Price RT11

	Connection Price (c/kW/day)
Connection price	2.317

8.3 Transmission prices

8.3.1 Use of system prices

The prices in the following table are applicable for reference tariff **TRT1**.

Table 8.20: Transmission prices TRT1

Substation	TNI	Use of System Price (c/kW/day)
Albany	WALB	20.202
Alcoa Pinjarra	WAPJ	5.730
Amherst	WAMT	4.809
Arkana	WARK	6.138
Australian Fused Materials	WAFM	3.985
Australian Paper Mills	WAPM	6.214
Baandee (WC)	WBDE	21.655
Balcatta	WBCT	6.289
Beckenham	WBEC	15.865
Beechboro	WBCH	5.585
Beenup	WBNP	24.227
Belmont	WBEL	4.949
Bentley	WBTY	6.442
Bibra Lake	WBIB	4.424
Binningup Desalination Plant	WBDP	3.418
Black Flag	WBKF	22.082
Boddington	WBOD	3.612
Boddington Gold Mine	WBGM	3.707
Boulder	WBLD	19.466
Bounty	WBNY	47.821
Bridgetown	WBTN	9.894
British Petroleum	WBPM	8.543
Broken Hill Kwinana	WBHK	6.667
Bunbury Harbour	WBUH	3.268
Busselton	WBSN	10.233
Byford	WBYF	4.422
Canning Vale	WCVE	5.057
Capel	WCAP	7.738
Carrabin	WCAR	25.016

Substation	TNI	Use of System Price (c/kW/day)
Cataby Kerr McGee	WKMC	9.228
Chapman	WCPN	14.396
Clarence Street	WCLN	8.309
Clarkson	WCKN	6.266
Cockburn Cement	WCCT	3.473
Cockburn Cement Ltd	WCCL	3.463
Collie	WCOE	13.979
Collier	WCOL	8.270
Cook Street	WCKT	5.950
Coolup	WCLP	17.332
Cottesloe	WCTE	6.444
Cunderdin	WCUN	18.945
Darlington	WDTN	6.370
Edgewater	WEDG	5.518
Edmund Street	WEDD	5.677
Eneabba	WENB	10.366
Forrest Ave	WFRT	8.320
Forrestfield	WFFD	6.522
Geraldton	WGTN	11.815
Glen Iris	WGNI	3.855
Golden Grove	WGGV	30.968
Gosnells	WGNL	5.250
Hadfields	WHFS	6.309
Hay Street	WHAY	6.309
Hazelmere	WHZM	4.890
Henley Brook	WHBK	5.391
Herdsman Parade	WHEP	9.568
Joel Terrace	WJTE	8.685
Joondalup	WJDP	5.914
Kalamunda	WKDA	6.664

Substation	TNI	Use of System Price (c/kW/day)
Katanning	WKAT	16.194
Kellerberrin	WKEL	20.761
Kewdale	WKDL	4.852
Kojonup	WKOJ	7.409
Kondinin	WKDN	8.941
Kwinana Alcoa	WAKW	1.533
Kwinana Desalination Plant	WKDP	4.209
Kwinana PWS	WKPS	3.074
Landsdale	WLDE	5.687
Maddington	WMDN	5.110
Malaga	WMLG	4.857
Mandurah	WMHA	4.172
Manjimup	WMJP	9.715
Manning Street	WMAG	7.063
Margaret River	WMRV	16.297
Marriott Road	WMRR	2.737
Marriott Road Barrack Silicon Smelter	WBSI	3.125
Mason Road	WMSR	2.440
Mason Road CSBP	WCBP	3.690
Mason Road Kerr McGee	WKMK	2.236
Meadow Springs	WMSS	4.732
Medical Centre	WMCR	7.485
Medina	WMED	3.523
Merredin 66kV	WMER	17.667
Midland Junction	WMJX	5.945
Milligan Street	WMIL	7.047
Moora	WMOR	9.951
Morley	WMOY	6.482
Mt Barker	WMBR	17.580
Muchea	WMUC	6.217

Substation	TNI	Use of System Price (c/kW/day)
Muchea Kerr McGee	WKMM	9.388
Muja PWS	WMPS	1.869
Mullaloo	WMUL	6.109
Mundaring Weir	WMWR	9.537
Munday	WMDY	6.585
Murdoch	WMUR	3.939
Myaree	WMYR	7.524
Narrogin	WNGN	21.433
Nedlands	WNED	7.046
North Beach	WNBH	6.289
North Fremantle	WNFL	6.325
North Perth	WNPH	5.368
Northam	WNOR	12.661
Nowgerup	WNOW	7.254
O'Connor	WOCN	6.562
Osborne Park	WOPK	6.820
Padbury	WPBY	6.371
Parkeston	WPRK	22.159
Parklands	WPLD	4.863
Piccadilly	WPCY	17.622
Picton 66kv	WPIC	4.504
Pinjarra	WPNJ	3.478
Rangeway	WRAN	13.399
Regans	WRGN	10.661
Riverton	WRTN	4.354
Rivervale	WRVE	6.769
Rockingham	WROH	3.730
Sawyers Valley	WSVY	10.566
Shenton Park	WSPA	7.330
South Fremantle 22kV	WSFT	4.739

Substation	TNI	Use of System Price (c/kW/day)
Southern River	WSNR	4.571
Summer St	WSUM	8.964
Sutherland	WSRD	5.368
Tate Street	WTTS	7.569
Three Springs	WTSG	9.883
Three Springs Terminal (Karara)	WTST	23.866
Tomlinson Street	WTLN	7.668
University	WUNI	8.127
Victoria Park	WVPA	7.400
Wagerup	WWGP	2.725
Wagin	WWAG	16.596
Waikiki	WWAI	4.077
Wangara	WWGA	5.840
Wanneroo	WWNO	6.145
Wellington Street	WWNT	8.919
Welshpool	WWEL	4.823
Wembley Downs	WWDN	7.196
West Kalgoorlie	WWKT	16.109
Western Collieries	WWCL	2.743
Western Mining	WWMG	3.224
Westralian Sands	WWSD	7.016
Willetton	WWLN	4.634
Worsley	WWOR	2.276
Wundowie	WWUN	12.915
Yanchep	WYCP	6.155
Yerbillon	WYER	24.054
Yilgarn	WYLN	18.067
Yokine	WYKE	6.666

The prices in the following table are applicable for reference tariffs **RT11**, **TRT2** and **TRT3**.

Table 8.21: Reference tariffs RT11, TRT2 and TRT3

Substation	TNI	Use of System Price (c/kW/day)
Albany	WALB	2.590
Alcoa Pinjarra	WAPJ	2.303
Badgingarra	WBGA	2.641
Bluewaters	WBWP	2.606
Boulder	WBLD	1.875
Cockburn PWS	WCKB	1.580
Collgar	WCGW	2.991
Collie PWS	WCPS	3.031
Emu Downs	WEMD	2.641
Geraldton	WGTN	0.443
Greenough Solar Farm	TMGS	0.564
Kemerton PWS	WKEM	2.106
Kwinana Alcoa	WAKW	1.629
Kwinana Donaldson Road	WKND	1.238
Kwinana PWS	WKPS	1.580
Landwehr (Alinta)	WLWT	1.966
Mason Road	WMSR	1.238
Merredin Power Station	TMDP	2.177
Merredin Solar Farm	WMSF	2.177
Muja PWS	WMPS	3.181
Mumbida Wind Farm	TMBW	2.680
Mungarra GTs	WMGA	2.633
Newgen Kwinana	WNGK	1.838
Newgen Neerabup	WGNN	1.619
Oakley (Alinta)	WOLY	2.192
Parkeston	WPKS	2.261
Pinjar GTs	WPJR	1.314
Tiwest GT	WKMK	1.277
Wagerup	WWGP	1.812

Substation	TNI	Use of System Price (c/kW/day)
Walkaway Windfarm	WWWF	2.907
Warradarge Wind Farm	WWDW	2.641
West Kalgoorlie GTs	WWKT	1.838
Worsley	WWOR	2.058
Yandin Wind Farm	WYDW	1.619

8.3.2 Common service prices

The prices in the following table are applicable for reference tariff **TRT1**.

Table 8.22: Common Service Prices TRT1

	Common Service Price (c/kW/day)
Common service price	6.032

8.3.3 Control system service prices

The prices in the following table are applicable for reference tariffs **RT11**, **TRT2** and **TRT3**.

Table 8.23: Control system service prices for reference tariffs RT11, TRT2 and TRT3

	Price (c/kW/day)
Control system service price (Generators)	0.255

The prices in the following table are applicable for reference tariff **TRT1**.

Table 8.24: Control system service prices for reference tariff TRT1

	Price (c/kW/day)
Control system service price (Loads)	2.263

8.4 Excess network usage charges – substation classification

The following table applies to reference tariffs **RT7, RT8, RT11, TRT1, TRT2** and **TRT3**.

Table 8.25: Values for ENUM for reference tariffs RT7, RT8, RT11, TRT1, TRT2 and TRT3

TNI	ENUM
ALB, BKF, BLD, BNY, PCY, PKS, WKT	2.5
All other substations	1

8.5 Other prices

The following table applies to reference tariff **RT25**.

Table 8.26: Supply abolishment charges for RT25

Location	Charge ($)
Whole current meters metropolitan area[10]	511.834
Whole current meters non-Metropolitan area	651.938
Non- whole current meters	User specific charge which reflects the costs to Western Power of undertaking the requested supply abolishment requested by the user and may consist of capital and non-capital costs.

The following table applies to reference tariffs **RT28 and RT29**.

Table 8.27: Charges for RT28 and RT29

Service	Charge per request ($)
RT28	6.280
RT29	6.280

The following table applies to reference tariffs **RT31**, **RT32**, and **RT33**.

Table 8.28: Metering prices for manual services

Metering Reference Service		Metropolitan Charge per site visit ($)	Country Metropolitan Charge per site visit ($)	Country Charge per site visit ($)
RT31	AMS standard	21.895	26.913	38.008
	AMS urgent	87.717	129.886	176.722
RT32	Standard	71.109	71.109	71.109
RT33	Standard	71.088	71.088	71.088
	Urgent	179.412	179.412	179.412

10 As defined in the Electricity Industry (Metering) Code

9. Applications and Queuing Policy fees

The Applications and Queuing Policy refers to several fees being published in the Price List. These prices are detailed below:

Table 9.1: Fees payable under the Applications and Queuing Policy

Fee type	Price
New Standard Access Contract Fee	$1,150.00
Access Contract Modification Fee	$140 per modification
Enquiry Fee	$3,500.00
Application Lodgement Fee	$5,000.00
Preliminary Offer Processing Fee	A variable fee
Preliminary Acceptance Fee	A variable fee
Distributed energy or other non-network solution assessment fee (B3 or C15)	A variable fee
Capacity allocation service fee – for a capacity swap reference service (D2)	$1,750.00
Remote load control/limitation (D6/RT26)	$6.280 per request

Table 9.2: Fees payable under the Applications and Queuing Policy

Application for Reference Service	New Connection Point Fee
A1 – Anytime Energy (Residential) Exit Service	$0.00 per connection point
A2 – Anytime Energy (Business) Exit Service	$0.00 per connection point
A3 – Time of Use Energy (Residential) Exit Service	$0.00 per connection point
A4 – Time of Use Energy (Business) Exit Service	$0.00 per connection point
A5 – High Voltage Metered Demand Exit Service C5 – High Voltage Metered Demand Bi-directional Service	$44.00 per connection point
A6 – Low Voltage Metered Demand Exit Service C6 – Low Voltage Metered Demand Bi-directional Service	$44.00 per connection point
A7 – High Voltage Contract Maximum Demand Exit Service C7 – High Voltage Contract Maximum Demand Bi-directional Service	$88.00 per connection point
A8 – Low Voltage Contract Maximum Demand Exit Service C8 – Low Voltage Contract Maximum Demand Bi-directional Service	$88.00 per connection point
A9 – Streetlighting Exit Service	$0.00 per connection point
A10 – Unmetered Supplies Exit Service	$0.00 per connection point
A11 – Transmission Exit Service	$175.00 per connection point
B1 – Distribution Entry Service	$175.00 per connection point

Application for Reference Service	New Connection Point Fee
B2 – Transmission Entry Service	$175.00 per connection point
B3 – Entry Service Facilitating a Distributed Generation or Other Non-Network Solution	$175.00 per connection point
C1 – Anytime Energy (Residential) Bi-directional Service	$0.00 per connection point
C2 – Anytime Energy (Business) Bi-directional Service	$0.00 per connection point
C3 – Time of Use (Residential) Bi-directional Service	$0.00 per connection point
C4 – Time of Use (Business) Bi-directional Service	$0.00 per connection point
A12 – 3 Part Time of Use Energy (Residential) Exit Service C9 – 3 Part Time of Use Energy (Residential) Bi-directional Service	$0.00 per connection point
A13 – 3 Part Time of Use Energy (Business) Exit Service C10 – 3 Part Time of Use Energy (Business) Bi-directional Service	$0.00 per connection point
A14 – 3 Part Time of Use Demand (Residential) Exit Service C11 – 3 Part Time of Use Demand (Residential) Bi-directional Service	$0.00 per connection point
A15 – 3 Part Time of Use Demand (Business) Exit Service C12 – 3 Part Time of Use Demand (Business) Bi-directional Service	$0.00 per connection point
A16 – Multi Part Time of Use Energy (Residential) Exit Service C13 – Multi Part Time of Use Energy (Residential) Bi-directional Service	$0.00 per connection point
A17 – Multi Part Time of Use Energy (Business) Exit Service C14 – Multi Part Time of Use Energy (Business) Bi-directional Service	$0.00 per connection point
C15 – Bi-directional Service Facilitating a Distributed Generation or Other Non-Network Solution	$175.00 per connection point
A18 – Super Off-Peak Time of User Energy (Residential) Exit Service C16 – Super Off-Peak Time of User Energy (Residential) Bidirectional Service	$0.00 per connection point
A19 – Super Off-Peak Time of User Energy (Business) Exit Service C17 – Super Off-Peak Time of User Energy (Business) Bidirectional Service	$0.00 per connection point
A20 – Super Off-Peak Time of User Demand (Residential) Exit Service C18 – Super Off-Peak Time of User Demand (Residential) Bidirectional Service	$0.00 per connection point
A21 – Super Off-Peak Time of User Demand (Business) Exit Service C19 – Super Off-Peak Time of User Demand (Business) Bidirectional Service	$0.00 per connection point
A22 – Low Voltage Electric Vehicle Demand Exit Service C20 – Low Voltage Electric Vehicle Demand Bidirectional Service	$44.00 per connection point
A23 – High Voltage Electric Vehicle Demand Exit Service C21 – High Voltage Electric Vehicle Demand Bidirectional Service	$88.00 per connection point
C22 – Transmission Connected Storage Bidirectional Service	$175.00 per connection point
C23 – Low Voltage Distribution Connected Storage Bidirectional Service	$44.00 per connection point

Application for Reference Service	New Connection Point Fee
C24 – High Voltage Distribution Connected Storage Bidirectional Service	$88.00 per connection point

The AQP includes two variable fees, the preliminary offer processing fee and preliminary acceptance fee. The methodology for these fees can be found on the following webpage:

https://westernpower.com.au/about/regulation/network-access-prices/

Appendix A

Supporting information

A.1 Access Code Compliance

This section outlines how Western Power's network tariffs for AA5 comply with the requirements of the Access Code in respect of the pricing principles.

A.1.1 Access Code requirements for TSS and pricing

Section 7.1B(a) of the Access Code specifies that Western Power's TSS must comply with the pricing principles. These pricing principles are set out in sections 7.3D to 7.3L.

The pricing objective specified in section 7.3 of the Access Code requires Western Power's reference tariffs that it charges in respect of its provision of reference services should reflect Western Power's efficient costs of providing those services.

The Access Code pricing principles are:

Pricing principles

7.3D For each reference tariff, the revenue expected to be recovered must lie on or between:

(a) an upper bound representing the stand-alone cost of service provision for customers to whom or in respect of whom that reference tariff applies; and

(b) a lower bound representing the avoidable cost of not serving the customers to whom or in respect of whom that reference tariff applies.

7.3E The charges paid by, or in respect of, different customers of a reference service may differ only to the extent necessary to reflect differences in the average cost of service provision to the customers.

7.3F The structure of reference tariffs must, so far as is consistent with the Code objective, accommodate the reasonable requirements of users collectively and end-use customers collectively.

7.3G Each reference tariff must be based on the forward-looking efficient costs of providing the reference service to which it relates to the customers currently on that reference tariff with the method of calculating such cost and the manner in which that method is applied to be determined having regard to:

(a) the additional costs likely to be associated with meeting demand from end-use customers that are currently on that reference tariff at times of greatest utilisation of the relevant part of the service provider's network; and

(b) The location of end-use customers that are currently on that reference tariff and the extent to which costs vary between different locations in the service provider's network.

7.3H The revenue expected to be recovered from each reference tariff must:

(a) reflect the service provider's total efficient costs of serving the customers that are currently on that reference tariff;

(b) when summed with the revenue expected to be received from all other reference tariffs, permit the service provider to recover the expected revenue for the reference services in accordance with the service provider's access arrangement; and

(c) comply with sections 7.3H(a) and 7.3H(b) in a way that minimises distortions to price signals for efficient usage that would result from reference tariffs that comply with the pricing principle set out in section 7.3G.

7.3I The structure of each reference tariff must be reasonably capable of being understood by customers that are currently on that reference tariff, including enabling a customer to predict the likely annual changes in reference tariffs during the access arrangement period, having regard to:

(a) the type and nature of those customers; and

(b) the information provided to, and the consultation undertaken with, those customers.

7.3J A reference tariff must comply with this Code and all relevant written laws and statutory instruments.

7.3K Despite sections 7.3D to 7.3H, a reference tariff may include a component, applicable where a user exceeds its contractual entitlements to transfer electricity into or out of the network at a connection point, which component is not set by reference to the service provider's costs, but instead is set at a level to act as a disincentive to the user exceeding its contractual entitlements. Such component should be determined having regard to the following principles:

(a) the component must be set at a level which provides a material disincentive to the user transferring into or out of the network quantities of electricity above its contractual entitlements; and

(b) in determining that level, regard is to be had to the potential adverse impact on the network, other customers and generators, and the service provider of the user transferring into or out of the network quantities of electricity above its contractual entitlements.

7.3L Unless otherwise determined by the Authority, section 7.3K does not apply to connection points servicing end use customers with a contract maximum demand not exceeding 1 MVA or end-use customers with solar photovoltaic generating plant not exceeding 1 MVA in capacity.

Tariff components

7.6 Unless a tariff structure statement containing alternative pricing methods would better achieve the Code objective, and subject to section 7.3K, for a reference service:

(a) the incremental cost of service provision should be recovered by tariff components that vary with usage or demand; and

(b) any amount in excess of the incremental cost of service provision should be recovered by tariff components that do not vary with usage or demand.

A.1.2 Access Code requirements for the price list

Section 8.12 of the Access Code outlines the obligations on Western Power with respect to the contents of the price list.

Contents of price list

8.12 A price list must:

(a) set out the proposed *reference tariffs* for the relevant *access arrangement period*;

(b) set out, for each proposed *reference tariff*, the *charging parameters,* and the elements of service to which each *charging parameter* relates;

(c) set out the nature of any variation or adjustment to the *reference tariff* that could occur during the course of the *pricing year* and the basis on which it could occur;

(d) demonstrate compliance with this Code and the *service provider's access arrangement*, including the *service provider's tariff structure statement* for the relevant *access arrangement period*;

(e) for any *pricing year* other than the first *pricing year* in an *access arrangement period*, demonstrate how each proposed *reference tariff* is consistent with the corresponding forecast price change for that *reference tariff* for the relevant *pricing year* as set out in the relevant *reference tariff change forecast*, or explain any material differences between them; and

(f) describe the nature and extent of change from the previous *pricing year* and demonstrate that the changes comply with this Code and the *service provider's access arrangement*.

Revision of reference tariff change forecast

8.13 At the same time as a *service provider* submits a *price list* under section 8.1, the *service provider* must submit to the *Authority* a revised *reference tariff change forecast* which sets out, for each *reference tariff*, the *service provider's* forecast of the weighted average annual price change for that *reference tariff* for each remaining pricing year of the *access arrangement period* and updated so as to take into account that *price list*.

Publication of information about tariffs

8.14 A *service provider* must maintain on its website:

(a) its current *tariff structure statement*;

(b) its current *reference tariff change forecast*; and

(c) its current approved *price list*.

8.15 A *service provider* must, within 5 *business days* from the date the *Authority publishes* its *final decision* under section 4.17 for that *service provider's access arrangement*, *publish* the *tariff structure statement* approved or contained in the approved *access arrangement* and the accompanying *reference tariff change forecast*.

8.16 A *service provider* must *publish* the information referred to in section 8.14 within 5 *business days* from the date the *Authority publishes* an *approved price list* under section 8.1A, section 8.6 or section 8.7 (as applicable) for that *service provider*.

A.1.3 Compliance with the Access Code pricing principles

This section demonstrates Western Power's compliance with the pricing principles set out in sections 7.3D to 7.3L of the Access Code. In particular, the pricing principles set out in sections 7.3D, 7.3G, 7.3H, 7.3I and 7.6.

A.1.3.1 Section 7.3D stand-alone and avoidable costs

Section 7.3D of the Access Code requires Western Power to ensure that the revenue recovered for each reference tariff lies between:

(a) an upper bound representing the stand-alone cost of service provision for customers to whom or in respect of whom that reference tariff applies; and

(b) a lower bound representing the avoidable cost of not serving the customers to whom or in respect of whom that reference tariff applies.

The stand-alone and avoidable cost methodologies are consistent with those used for the 2022-27 TSS. These approaches are used to calculate the revenues for each reference tariff associated with each cost methodology. These costs are compared with the expected revenue to be recovered from Western Power's proposed reference tariffs.

The revenue expected to be recovered from each of Western Power's reference tariffs in 2024-25 is compared with the stand-alone and avoidable costs in Table A.1.

Table A.1 Demonstration Reference Tariffs are between avoidable and stand-alone cost of service provision for 2024-25 ($M Nominal)

Reference Service	Reference Tariff	Avoidable Cost	Stand-alone Cost	Forecast Revenue Recovered from Reference Tariff
A1	RT1	77.08	1,173.05	348.46
A2	RT2	10.54	911.36	80.07
A3	RT3	0.42	870.48	3.23
A4	RT4	1.91	876.35	19.65
A5, C5	RT5	4.78	623.37	45.36
A6, C6	RT6	14.87	927.04	136.30
A7, C7	RT7	24.94	702.51	206.57
A8, C8	RT8	1.23	873.64	14.54
A9	RT9	0.33	910.13	50.55
A10	RT10	-	868.80	7.19
B1	RT11	1.04	873.01	5.21
C1	RT13	42.66	1,033.09	164.88
C2	RT14	0.52	870.87	3.17
C3	RT15	1.08	873.10	5.05
C4	RT16	0.76	871.79	4.54
A12, C9	RT17	14.90	929.66	89.49
A13, C10	RT18	14.33	926.38	60.76

Reference Service	Reference Tariff	Avoidable Cost	Stand-alone Cost	Forecast Revenue Recovered from Reference Tariff
A14, C11	RT19	0.14	869.34	0.88
A15, C12	RT20	1.85	876.12	6.64
A16, C13	RT21	148.53	1,437.20	318.51
A17, C14	RT22	0.15	869.42	2.05
A19, C17	RT34	25.91	972.04	148.88
A18, C16	RT35	6.33	892.89	7.74
A21, C19	RT36	6.63	895.22	34.33
A20, C18	RT37	38.72	1,016.17	73.09
C23	RT38	0.00	868.81	1.15
C24	RT39	0.01	604.64	1.15
A22, C20	RT40	0.03	868.91	0.19
A23, C21	RT41	0.00	604.63	0.12
A11	TRT1	2.39	423.97	56.66
B2	TRT2	2.39	86.33	62.64
C22	TRT3 *	2.39	76.69	1.32

Notes: * TRT3 has been newly introduced for AA5 and Western Power considers the amount of revenue recovered from transmission connected storage customers will increase above the avoidable cost level as more customers connect to the network – there is currently only one transmission connected storage customer, with several others in the advanced stages of receiving connection offers.

A.1.3.2 Tariffs reflect forward-looking efficient costs

Section 7.3G of the Access Code requires each reference tariff to be based on the forward-looking efficient costs of providing the reference service to which it relates to the customers currently on that reference tariff with the method of calculating such cost and the manner in which that method is applied to be determined having regard to:

a. the additional costs likely to be associated with meeting demand from end-use customers that are currently on that reference tariff at times of greatest utilisation of the relevant part of the service provider's network; and

b. the location of end-use customers that are currently on that reference tariff and the extent to which costs vary between different locations in the service provider's network.

Table A.2 below outlines how Western Power allocates the revenue across its customer groups in accordance with sections 3.1 and 3.2 of the TSS under the approved AA5 access arrangement. Western Power's process ensures that tariffs reflect the efficient costs incurred in supplying customers using those tariffs.

Table A.2 Cost allocation of distribution and transmission target revenue to relevant customer groups and cost pools for 2024-25 ($M nominal)

Customer groups	Distribution Revenue							Transmission Revenue included in Distribution	Bundled Revenue	Proportion of total costs
	High voltage	Low voltage	Transformers	Metering	Streetlights	Admin	Total			
Residential	457.99	386.27	52.72	33.57	0.00	90.80	**1,021.35**	225.74	**1,021.35**	**52.10%**
LV business - small	196.16	155.45	17.50	20.75	0.00	56.11	**445.97**	78.90	**445.97**	**22.75%**
LV business - large	78.29	8.16	7.56	5.68	0.00	15.37	**115.06**	21.34	**115.06**	**5.87%**
HV business	148.63	15.41	12.71	11.65	0.00	31.51	**219.90**	79.38	**219.90**	**11.22%**
Streetlights	0.00	0.43	0.00	0.00	34.29	0.00	**34.72**	7.84	**34.72**	**1.77%**
Unmetered	0.77	1.79	0.08	0.00	0.00	0.12	**2.75**	0.72	**2.75**	**0.14%**
Generators	0.00	0.00	0.00	0.00	0.00	0.00	**0.00**	0.00	**0.00**	**0.00%**
Transmission	0.00	0.00	0.00	0.00	0.00	0.00	**0.00**	120.62	**120.62**	**6.15%**
Total	**881.84**	**567.51**	**90.57**	**71.65**	**34.29**	**193.90**	**1,839.76**	**534.54**	**1,960.38**	**100.00%**

Distribution revenue of $1,840 million is allocated across the distribution customer groups (and subsequently the reference tariffs) according to the usage by customers of the various voltage steps (represented by asset categories) involved. Under Western Power's cost allocation methodology, the proportion of low voltage cost allocation determined by demand is equal to 50 per cent.

The efficient costs are apportioned across these asset categories, with customers' use of these assets determined by the customers' diversified demand and usage. Some assets are apportioned according to customer numbers, for example connection services.

A.1.3.3 Revenue expected to be recovered from reference tariffs

Section 7.3H of the Access Code requires the revenue expected to be recovered from reference tariffs to:

a. reflect the service provider's total efficient costs of serving the customers that are currently on that reference tariff;
b. when summed with the revenue expected to be received from all other reference tariffs, permit the service provider to recover the expected revenue for the reference services in accordance with the service provider's access arrangement; and
c. comply with sections 7.3H(a) and 7.3H(b) in a way that minimises distortions to the price signals for efficient usage that would result from reference tariffs that comply with the pricing principle set out in section 7.3G.

Table A.3 below demonstrates how the cost allocation of distribution and transmission target revenues to the relevant customer groups and cost pools has been allocated to the individual reference tariffs in a manner that when summed permits Western Power to recover the expected revenue for the reference services in accordance with the energy and customer numbers as set out in Table 47 of the access arrangement contract.

Table A.3 Bundled reference service revenue recovered from distribution and transmission connection points for 2024-25 ($M nominal)

Reference tariff	MWh	Customer numbers	Forecast bundled revenue recovered
RT1 – Anytime Energy (Residential)	1,801,013	407,450	348.46
RT2 – Anytime Energy (Business)	390,676	37,444	80.07
RT3 – Time of Use Energy (Residential)	17,556	2,955	3.23
RT4 – Time of Use Energy (Business)	146,278	1,848	19.65
RT5 – High Voltage Metered Demand	675,052	324	45.36
RT6 – Low Voltage Metered Demand	1,663,959	3,721	136.30
RT7 – High Voltage Contract Maximum Demand	3,346,400	387	206.57
RT8 – Low Voltage Contract Maximum Demand	268,833	53	14.54
RT9 – Streetlighting	140,037	297,685	50.55
RT10 – Unmetered Supplies	47,720	20,162	7.19
RT11 – Distribution Entry	197	27	5.21
RT13 – Anytime Energy (Residential) Bi-directional	866,314	189,557	164.88
RT14 – Anytime Energy (Business) Bi-directional	17,218	1,200	3.17
RT15 – Time of Use (Residential) Bi-directional	26,111	5,116	5.05
RT16 – Time of Use (Business) Bi-directional	35,220	247	4.54
RT17 – Time of Use Energy (Residential)	553,875	88,838	89.49
RT18 – Time of Use Energy (Business)	345,079	16,496	60.76
RT19 – Time of Use Demand (Residential)	9,716	133	0.88
RT20 – Time of Use Demand (Business)	38,781	247	6.64
RT21 – Multi Part Time of Use Energy (Residential)	1,600,835	372,518	318.51
RT22 – Multi Part Time of Use Energy (Business)	13,688	247	2.05
RT34 – Super Off-peak Time of Use Energy (Business)	1,006,180	48,099	148.88
RT35 – Super Off-peal Time of Use Energy (Residential)	39,716	9,242	7.74
RT36 – Super Off-peak Time of Use Demand (Business)	213,217	1,358	34.33
RT37 – Super Off-peak Time of Use Demand (Residential)	157,648	36,685	73.09
RT38 – Low Voltage Distribution Storage	0	5	1.15
RT39 – High Voltage Distribution Storage	0	5	1.15
RT40 – Low Voltage Electric Vehicle Charging	332	20	0.19
RT41 – High Voltage Electric Vehicle Charging	66	4	0.12
Total Bundled Target Revenue from distribution customers	**13,421,716**	**1,542,073**	**1,839.76**

Reference tariff	MWh	Customer numbers	Forecast bundled revenue recovered
TRT1 - Transmission exit	743	42	56.66
TRT2 - Transmission entry	5,435	38	62.64
TRT3 - Transmission storage	0	2	1.32
Total Bundled Target Revenue from transmission customers	**6,178**	**82**	**120.62**
Total Bundled Target Revenue	**13,427,894**	**1,542,155**	**1,960.37**

A.1.3.4 Incremental cost of service provision recovered by variable component of tariffs

Section 7.6 of the Access Code states that unless a TSS containing alternative pricing methods would better achieve the Code objective, and subject to section 7.3K, for a reference service:

c. the incremental cost (avoidable cost) of service provision should be recovered by tariff components that vary with usage or demand; and

d. any amount in excess of the incremental cost (avoidable cost) of service provision should be recovered by tariff components that do not vary with usage or demand.

Western Power has had regard to this requirement in setting tariffs. The following Table A.4 shows that the variable components for 2024-25 tariffs exceeds the avoidable cost calculated for the comparison of stand-alone and avoidable costs above, with the exception of residential reference tariffs RT21 and RT35 which are priced lower than the avoidable cost (commentary follows Table A.4).

Table A.4 Demonstration that variable costs exceed avoidable costs of reference tariff provision for 2024-25 ($M nominal)

Reference Service	Reference Tariff	Avoidable Cost	Variable tariff components
A1	RT1	77.08	172.69
A2	RT2	10.54	50.53
A3	RT3	0.42	1.95
A4	RT4	1.91	17.00
A5, C5	RT5	4.78	18.55
A6, C6	RT6	14.87	90.35
A7, C7	RT7	24.94	119.81
A8, C8	RT8	1.23	1.32
A9	RT9	0.33	7.62
A10	RT10	0.00	2.49
B1	RT11	1.04	5.20
C1	RT13	42.66	83.10

Reference Service	Reference Tariff	Avoidable Cost	Variable tariff components
C2	RT14	0.52	2.22
C3	RT15	1.08	2.84
C4	RT16	0.76	4.18
A12, C9	RT17	14.90	48.68
A13, C10	RT18	14.33	46.79
A14, C11	RT19	0.14	0.81
A15, C12	RT20	1.85	6.39
A16, C13	RT21 *	148.53	147.36
A17, C14	RT22	0.15	1.85
A19, C17	RT34	25.91	110.94
A18, C16	RT35 ^	6.33	3.76
A21, C19	RT36	6.63	32.59
A20, C18	RT37	38.72	57.27
C23	RT38	0.00	1.13
C24	RT39	0.01	1.13
A22, C20	RT40	0.03	0.16
A23, C21	RT41	0.00	0.11

Notes: * RT21 has variable components that are currently set below cost reflectivity, although the gap has narrowed significantly compared with the FY24 Price List. As Western Power transitions this tariff towards greater cost reflectivity over AA5, we expect the variable tariff component to increase above avoidable costs.
^ RT35 has been newly introduced for AA5 and Western Power considers the amount of revenue recovered from variable tariff components will increase as users churn end-use small business consumers onto this tariff.

A.1.4 Compliance with the Access Code price list requirements

This section demonstrates Western Power's compliance with the pricing list requirements set out in sections 8.12 and 8.13 of the Access Code.

Contents of the price list

Section 2 of this price list sets out the reference services and associated tariffs Western Power intends to provide to users over AA5.

Sections 5, 6 and 7 of this price list provide a technical breakdown of each reference tariff into each of its component parts, charging windows and the elements of service to which each charging parameter relates.

Sections 5, 6 and 7 of this price list provide information to users on the variations or adjustments that may occur over the course of a pricing year. For example, information on excess network charging arrangements, and the process to update a user's metered maximum demand over a rolling 12-month period.

Section 1.4 demonstrates compliance with the form of price control formula contained within the approved *access arrangement contract*. Furthermore, Sections 1.6 and 5, 6 and 7 demonstrate compliance with the tariff structures contained in the tariff structure statement that forms part of the approved access arrangement.

Section 1.5.2 demonstrates compliance with the requirement for the weighted average price changes for each reference tariff to be consistent with the reference tariff change forecast compared with the previous pricing year.

A.2 Extracts from Western Power's pricing model

The TSS sets out the detailed methodology which allocates total revenue into transmission and distribution 'cost pools' and then allocates these cost pools to customer groups and ultimately tariffs. Below are several extracts from the pricing model updated for 2024-25.

A.2.1 Transmission pricing cost pools

The following sets out the allocation of revenue to the transmission cost pools for the 2024-25 pricing year.

Table A.5 - Transmission Pricing Cost Pools for 2024-25 ($M Nominal)

Cost Pool	Allocated Revenue
Entry connection	12.37
Exit connection HV	2.95
Exit connection LV	140.68
CSS entry	5.50
CSS exit	39.61
UOS entry	44.81
UOS exit	124.59
Common service	163.78
Metering CT/VT	0.25
Total	**534.54**

A.2.2 Distribution pricing cost pools

Applying the distribution pricing methodology, the following tables details the allocation of the distribution network revenue entitlement (which includes TEC) to the cost pools:

Table A.6: -Distribution Cost Pools for 2024-25 ($M Nominal)

Cost Pool	Locational Zone					
	CBD	Urban	Mining	Mixed	Rural	Total
High Voltage Network	5.97	208.45	10.69	262.51	394.20	**881.84**
Low Voltage Network	7.06	365.82	0.28	132.93	61.41	**567.51**
Transformers	2.65	42.40	0.31	25.19	20.02	**90.57**
Streetlight Assets	0.73	28.69	0.52	19.57	22.13	**71.65**
Metering	0.35	13.73	0.25	9.37	10.59	**34.29**
Administration	1.98	77.65	1.42	52.97	59.89	**193.90**
Revenue requirement	**18.74**	**736.75**	**13.47**	**502.55**	**568.24**	**1,839.76**

Table A.7: Derivation of Streetlight and Metering Costs ($M Nominal)

2024-25 cost of service	Streetlights	Metering
Opening RAB	100.75	320.08
Return on asset	7.61	13.74
Depreciation	10.72	28.56
Opex	19.42	24.99
Indirect cost allocation	-	4.36
Cost of service	**37.76 ***	**71.65**

Notes: * The cost of service for streetlighting in this Table A.7 represents the unsmoothed target revenue. For the purposes of determining the RT9 asset charges in this proposed FY25 price list, the smoothed target revenue used was $34.29 million (nominal).

A.3 Customer bill impacts (network component of reference tariffs only)

Our desired price path for AA5, as explained in Appendix F.1 – Reference Tariff Change Forecast and replicated in section 1.5.1 above, applies to the average network revenue recovered from our customers. This approach is intended to on average limit the bill impacts to end-users; however, some end-users may experience different outcomes due to the particular characteristics of their energy use.

In this section, we provide context to the potential network bill impacts on different types of end-users on each reference tariff. We present our network bill impacts as the rate of bill change, as a percentage, in nominal terms and have worked to remain within the constraints of our pricing strategy.

A.3.1 Residential end-users

As the network service provider does not assign end-users to a particular tariff, the network bill impact analysis focuses on the price impact between years for end-users on a particular reference tariff. Our bill impact analysis is performed on five distinct, representative residential end-users, including:

- a low consumption residential end-user – the 25th percentile of total annual energy consumption from our residential end-user sample;
- a medium consumption residential end-user – the median of total annual energy consumption from our residential end-user sample;
- a high consumption residential end-user – the 75th percentile of total annual energy consumption from our residential end-user sample;
- a typical residential end-user with solar – the median of total annual energy consumption from our residential end-user sample for end-users with solar installations only; and
- a typical residential end-user without solar – the median of total annual energy consumption from our residential end-user sample for end-users without solar installations.

A.3.1.1 RT1/RT13 – Anytime energy residential tariffs

The customer network bill impacts for RT1 and RT13 over AA5 is shown in Table A.8.

Table A.8: Annual network bill impacts over AA5 for RT1/RT13

Representative end-user	Annual change FY22 to FY23	Annual change FY23 to FY24	Baseline $/year FY24	Annual change FY24 to FY25	Baseline $/year FY25	Annualised change over AA5
Low consumption end-user	0%	5%	556	11%	616	**3%**
Medium consumption end-user	0%	4%	683	10%	751	**3%**
High consumption end-user	0%	3%	826	9%	903	**2%**
Typical solar end-user	0%	3%	742	10%	814	**2%**
Typical non-solar end-user	0%	4%	673	10%	741	**3%**

A.3.1.2 RT3/RT15 – Time of use residential tariffs

The customer network bill impacts for RT3 and RT15 over AA5 is shown in Table A.9.

Table A.9: Annual network bill impacts over AA5 for RT3/RT15

Representative end-user	Annual change FY22 to FY23	Annual change FY23 to FY24	Baseline $/year FY24	Annual change FY24 to FY25	Baseline $/year FY25	Annualised change over AA5
Low consumption end-user	0%	12%	599	12%	668	**9%**
Medium consumption end-user	0%	14%	756	11%	839	**10%**
High consumption end-user	0%	14%	931	10%	1,029	**11%**
Typical solar end-user	0%	14%	796	11%	884	**10%**
Typical non-solar end-user	0%	13%	744	11%	825	**10%**

A.3.1.3 RT17 – 3 part time of use residential tariff

The customer network bill impacts for RT17 over AA5 is shown in Table A.10.

Table A.10: Annual network bill impacts over AA5 for RT17

Representative end-user	Annual change FY22 to FY23	Annual change FY23 to FY24	Baseline $/year FY24	Annual change FY24 to FY25	Baseline $/year FY25	Annualised change over AA5
Low consumption end-user	0%	9%	562	12%	627	**8%**
Medium consumption end-user	0%	11%	675	11%	748	**10%**
High consumption end-user	0%	12%	802	10%	883	**11%**
Typical solar end-user	0%	12%	734	11%	813	**11%**
Typical non-solar end-user	0%	11%	667	11%	739	**10%**

A.3.1.4 RT19 – 3 part time of use demand residential tariff

The customer network bill impacts for RT19 over AA5 is shown in Table A.11.

Table A.11: Annual network bill impacts over AA5 for RT19

Representative end-user	Annual change FY22 to FY23	Annual change FY23 to FY24	Baseline $/year FY24	Annual change FY24 to FY25	Baseline $/year FY25	Annualised change over AA5
Low consumption end-user	0%	13%	574	12%	640	**8%**
Medium consumption end-user	0%	14%	682	11%	755	**8%**
High consumption end-user	0%	15%	798	10%	880	**9%**
Typical solar end-user	0%	14%	732	11%	812	**9%**
Typical non-solar end-user	0%	14%	672	11%	745	**8%**

A.3.1.5 RT21 – Multi part time of use residential tariff

The customer network bill impacts for RT19 over AA5 is shown in Table A.12.

Table A.12: Annual network bill impacts over AA5 for RT21

Representative end-user	Annual change FY22 to FY23	Annual change FY23 to FY24	Baseline $/year FY24	Annual change FY24 to FY25	Baseline $/year FY25	Annualised change over AA5
Low consumption end-user	0%	12%	581	12%	653	**9%**
Medium consumption end-user	0%	14%	709	12%	795	**11%**
High consumption end-user	0%	15%	854	12%	955	**12%**
Typical solar end-user	0%	14%	771	13%	869	**12%**
Typical non-solar end-user	0%	14%	700	12%	784	**11%**

A.3.1.6 RT35 – Super off-peak time of use energy residential tariff

The customer network bill impacts for RT35 over AA5 is shown in Table A.13.

Table A.13: Annual network bill impacts over AA5 for RT35

Representative end-user	Annual change FY22 to FY23	Annual change FY23 to FY24	Baseline $/year FY24	Annual change FY24 to FY25	Baseline $/year FY25	Annualised change over AA5
Low consumption end-user	-	0%	537	11%	596	**2%**
Medium consumption end-user	-	0%	651	10%	715	**2%**
High consumption end-user	-	0%	779	9%	851	**2%**
Typical solar end-user	-	0%	754	9%	825	**2%**
Typical non-solar end-user	-	0%	642	10%	707	**2%**

A.3.1.7 RT37 – Super off-peak time of use demand residential tariff

The customer network bill impacts for RT37 over AA5 is shown in Table A.14.

Table A.14: Annual network bill impacts over AA5 for RT37

Representative end-user	Annual change FY22 to FY23	Annual change FY23 to FY24	Baseline $/year FY24	Annual change FY24 to FY25	Baseline $/year FY25	Annualised change over AA5
Low consumption end-user	-	0%	526	14%	599	**2%**
Medium consumption end-user	-	0%	622	14%	711	**2%**
High consumption end-user	-	0%	725	15%	833	**2%**
Typical solar end-user	-	0%	700	15%	804	**2%**
Typical non-solar end-user	-	0%	613	14%	701	**2%**

A.3.2 Small business end-users

As with our residential end-users, our network bill impact analysis is performed on five distinct, representative small business end-users, including:

- a low consumption small business end-user – the 25th percentile of total annual energy consumption from our small business end-user customer sample;
- a medium consumption small business end-user – the median of total annual energy consumption from our small business end-user customer sample;
- a high consumption small business end-user – the 75th percentile of total annual energy consumption from our small business end-user customer sample;
- a typical small business end-user with solar – the median of total annual energy consumption from our small business end-user sample for end-users with solar installations only; and
- a typical small business end-user without solar – the median of total annual energy consumption from our small business end-user sample for end-users without solar installations

A.3.2.1 RT2/RT14 – Anytime energy business tariffs

The customer network bill impacts for RT2 and RT14 over AA5 is shown in Table A.15.

Table A.15: Annual network bill impacts over AA5 for RT2/RT14

Representative end-user	Annual change FY22 to FY23	Annual change FY23 to FY24	Baseline $/year FY24	Annual change FY24 to FY25	Baseline $/year FY25	Annualised change over AA5
Low consumption end-user	0%	6%	920	12%	1,030	**4%**
Medium consumption end-user	0%	5%	1,323	10%	1,460	**2%**
High consumption end-user	0%	3%	2,015	9%	2,199	**2%**
Typical solar end-user	0%	3%	1,947	9%	2,127	**2%**
Typical non-solar end-user	0%	3%	2,305	9%	2,509	**1%**

A.3.2.2 RT4/RT16 – Time of use business tariffs

The customer network bill impacts for RT4 and RT16 over AA5 is shown in Table A.16.

Table A.16: Annual network bill impacts over AA5 for RT4/RT16

Representative end-user	Annual change FY22 to FY23	Annual change FY23 to FY24	Baseline $/year FY24	Annual change FY24 to FY25	Baseline $/year FY25	Annualised change over AA5
Low consumption end-user	0%	7%	1,545	13%	1,742	**6%**
Medium consumption end-user	0%	9%	1,993	12%	2,229	**8%**
High consumption end-user	0%	11%	2,817	11%	3,120	**10%**
Typical solar end-user	0%	11%	2,448	12%	2,736	**9%**
Typical non-solar end-user	0%	12%	3,050	11%	3,378	**10%**

A.3.2.3 RT18 – 3 part time of use business tariff

The customer network bill impacts for RT18 over AA5 is shown in Table A.17.

Table A.17: Annual network bill impacts over AA5 for RT18

Representative end-user	Annual change FY22 to FY23	Annual change FY23 to FY24	Baseline $/year FY24	Annual change FY24 to FY25	Baseline $/year FY25	Annualised change over AA5
Low consumption end-user	0%	9%	949	16%	1,103	**8%**
Medium consumption end-user	0%	11%	1,365	14%	1,563	**11%**
High consumption end-user	0%	13%	2,097	13%	2,374	**13%**
Typical solar end-user	0%	13%	2,004	14%	2,277	**13%**

Representative end-user	Annual change FY22 to FY23	Annual change FY23 to FY24	Baseline $/year FY24	Annual change FY24 to FY25	Baseline $/year FY25	Annualised change over AA5
Typical non-solar end-user	0%	14%	2,369	13%	2,671	**14%**

A.3.2.4 RT20 – 3 part time of use demand business tariff

The customer network bill impacts for RT20 over AA5 is shown in Table A.18.

Table A.18: Annual network bill impacts over AA5 for RT20

Representative end-user	Annual change FY22 to FY23	Annual change FY23 to FY24	Baseline $/year FY24	Annual change FY24 to FY25	Baseline $/year FY25	Annualised change over AA5
Low consumption end-user	0%	15%	1,213	13%	1,372	**8%**
Medium consumption end-user	0%	16%	1,617	12%	1,818	**9%**
High consumption end-user	0%	16%	2,320	12%	2,598	**11%**
Typical solar end-user	0%	16%	2,212	12%	2,485	**10%**
Typical non-solar end-user	0%	16%	2,566	12%	2,866	**11%**

A.3.2.5 RT22 – Multi part time of use energy business tariff

The customer network bill impacts for RT22 over AA5 is shown in Table A.19.

Table A.19: Annual network bill impacts over AA5 for RT22

Representative end-user	Annual change FY22 to FY23	Annual change FY23 to FY24	Baseline $/year FY24	Annual change FY24 to FY25	Baseline $/year FY25	Annualised change over AA5
Low consumption end-user	0%	8%	968	12%	1,088	**7%**
Medium consumption end-user	0%	10%	1,395	11%	1,551	**10%**
High consumption end-user	0%	12%	2,152	10%	2,375	**12%**
Typical solar end-user	0%	12%	2,012	12%	2,247	**12%**
Typical non-solar end-user	0%	12%	2,420	10%	2,661	**13%**

A.3.2.6 RT34 – Super off-peak time of use energy business tariff

The customer network bill impacts for RT34 over AA5 is shown in Table A.20.

Table A.20: Annual network bill impacts over AA5 for RT34

Representative end-user	Annual change FY22 to FY23	Annual change FY23 to FY24	Baseline $/year FY24	Annual change FY24 to FY25	Baseline $/year FY25	Annualised change over AA5
Low consumption end-user	-	0%	882	12%	991	**2%**
Medium consumption end-user	-	0%	1,213	11%	1,350	**2%**

Representative end-user	Annual change FY22 to FY23	Annual change FY23 to FY24	Baseline $/year FY24	Annual change FY24 to FY25	Baseline $/year FY25	Annualised change over AA5
High consumption end-user	-	0%	1,782	10%	1,965	**1%**
Typical solar end-user	-	0%	1,859	10%	2,051	**1%**
Typical non-solar end-user	-	0%	2,022	10%	2,226	**1%**

A.3.2.7 RT36 – Super off-peak time of use demand business tariff

The customer network bill impacts for RT36 over AA5 is shown in Table A.21.

Table A.21: Annual network bill impacts over AA5 for RT36

Representative end-user	Annual change FY22 to FY23	Annual change FY23 to FY24	Baseline $/year FY24	Annual change FY24 to FY25	Baseline $/year FY25	Annualised change over AA5
Low consumption end-user	-	0%	1,440	4%	1,495	**2%**
Medium consumption end-user	-	0%	1,771	5%	1,853	**2%**
High consumption end-user	-	0%	2,332	6%	2,463	**2%**
Typical solar end-user	-	0%	2,364	6%	2,500	**2%**
Typical non-solar end-user	-	0%	2,555	6%	2,704	**1%**

A.4 TEC in the Components of Reference Tariffs

This section details the amounts associated with TEC that are embedded within the reference tariff components.

Western Power pays TEC to the WA State Government to contribute towards maintaining the financial viability of Horizon Power under Part 9A of the *Electricity Industry Act 2004*. The purpose of TEC is to enable the regulated retail tariffs for electricity that is not supplied from the South West Interconnected System (SWIS) to be, so far as is practicable, the same as the regulated retail tariffs for electricity that is supplied from the SWIS.

The graphs and tables detailed in previous sections are inclusive of TEC. The tables that follow in this section separate out the amounts of TEC that are embedded within the distribution reference tariff components.

A.4.1 TEC Forecast Revenue

The following table details the forecast TEC, by tariff, which will be collected from distribution connection points.

Table A.22: TEC Recovered from Distribution Connection Points for 2024-25 ($M Nominal)

Reference Tariff	kWh	Number Customers	Forecast TEC Recovered
RT1 - Anytime Energy (Residential)	1,801,013	407,450	34.71

Reference Tariff	kWh	Number Customers	Forecast TEC Recovered
RT2 - Anytime Energy (Business)	390,676	37,444	7.70
RT3 - Time of Use Energy (Residential)	17,556	2,955	0.29
RT4 - Time of Use Energy (Business)	146,278	1,848	2.38
RT5 - High Voltage Metered Demand	675,052	324	14.39
RT6 - Low Voltage Metered Demand	1,663,959	3,721	35.49
RT7 - High Voltage Contract Maximum Demand	3,346,400	387	8.80
RT8 - Low Voltage Contract Maximum Demand	268,833	53	1.30
RT9 – Streetlighting	140,037	297,685	1.06
RT10 - Unmetered Supplies	47,720	20,162	0.38
RT11 - Distribution Entry	197	27	Not Applicable
RT13 – Anytime Energy (Residential) Bi-directional	866,314	189,557	16.69
RT14 – Anytime Energy (Business) Bi-directional	17,218	1,200	0.34
RT15 – Time of Use (Residential) Bi-directional	26,111	5,116	0.41
RT16 – Time of Use (Business) Bi-directional	35,220	247	0.58
RT17 - Time of Use Energy (Residential)	553,875	88,838	10.26
RT18 - Time of Use Energy (Business)	345,079	16,496	6.53
RT19 – Time of Use Demand (Residential)	9,716	133	0.18
RT20 – Time of Use Demand (Business)	38,781	247	0.71
RT21 – Multi Part Time of Use Energy (Residential)	1,600,835	372,518	30.01
RT22 – Multi Part Time of Use Energy (Business)	13,688	247	0.26
RT34 – Super Off-peak Time of Use Energy (Business)	1,006,180	48,099	18.75
RT35 – Super Off-peal Time of Use Energy (Residential)	39,716	9,242	0.76
RT36 – Super Off-peak Time of Use Demand (Business)	213,217	1,358	3.97
RT37 – Super Off-peak Time of Use Demand (Residential)	157,648	36,685	3.03
RT40 – Low Voltage Electric Vehicle Charging	332	20	0.00
RT41 – High Voltage Electric Vehicle Charging	66	4	0.00
Total			**199**