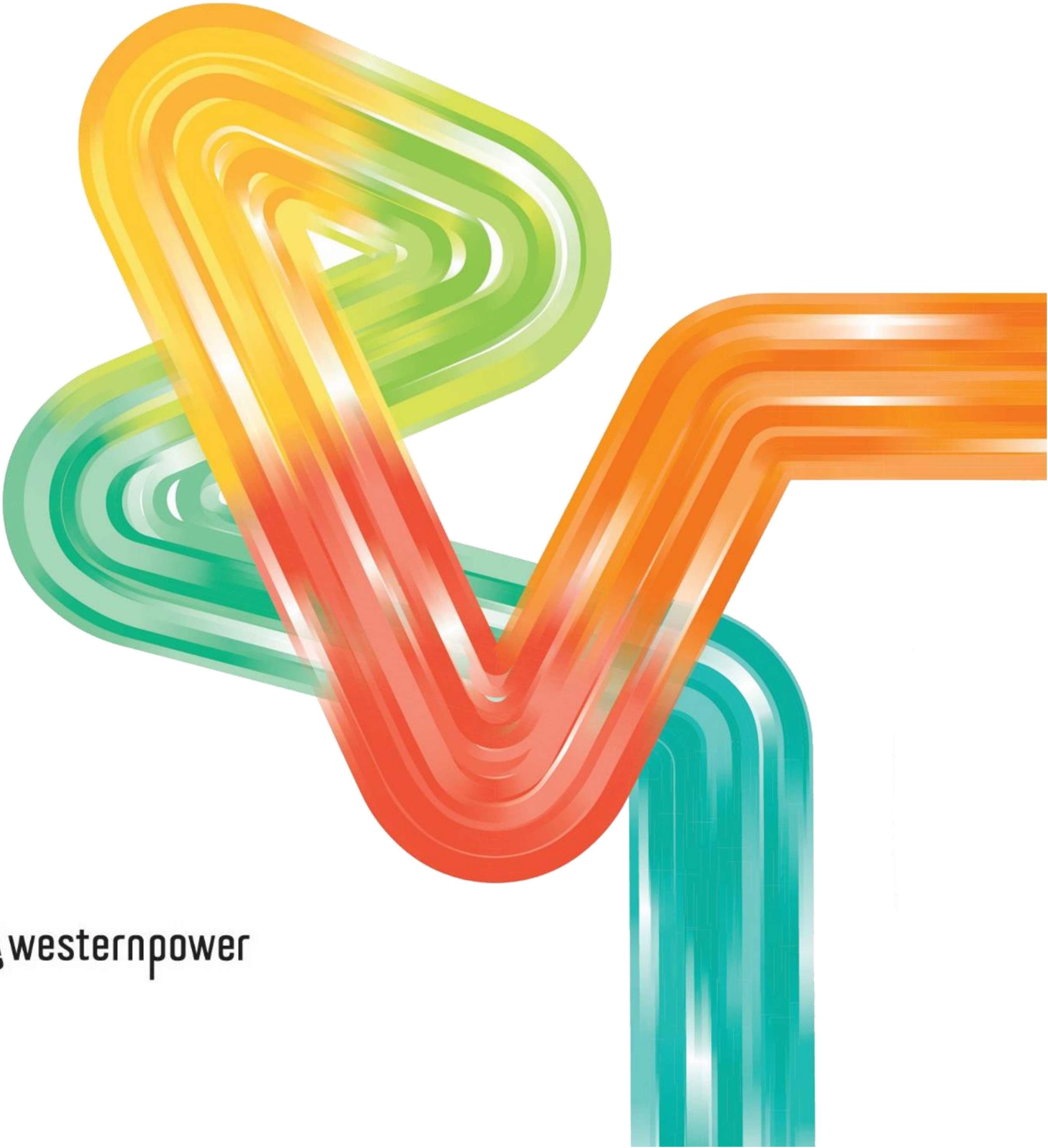
2026-27 Price List for the Western Power Network

Proposed by Western Power on 31 March 2026

Approved by ERA on 15 May 2026



Contents

1. Introduction

1.1 Overview

This document details Western Power's price list for the pricing year commencing on 1 July 2026 and ending on 30 June 2027, which represents the fifth 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 at its greatest.
- Introduction of new reference tariffs for grid-connected distribution (RT38 and RT39) and transmission voltage level connected storage (TRT3) customers.
- 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

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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 2026-27

1.4.1 Revenue targets for 2026-27

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 2026-27 ($M nominal)

Maximum total target revenue	2025-26	2026-27
NR_t	1,862	1,990

Maximum total target revenue	2025-26	2026-27
TEC_t	236	251
$DTEC_t$	+14	-2.9
TNR_t	2,111	2,238

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 2026-27 ($M)

Target Revenue	Revenue (Real)	Revenue (Nominal)
Target Revenue ($NR_{2026-27}$)	1,813	2,238

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 2026-27 Inflation Factor

December 2020 – December 2021	3.50%
December 2021 – December 2022	7.80%
December 2022 – December 2023	4.10%
December 2023 – December 2024	2.40%
December 2024 – December 2025	3.80%
Derived Inflation Factor	1.235

1.5 Proposed pricing strategy for 2026-27 price list

1.5.1 Overview of pricing strategy for the 2026-27 price list

This section sets out and describes how Western Power's pricing strategy for the 2026-27 Price List complies 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.
- Residential:
  - Western Power has proposed a gradual transition to efficiency for residential tariffs. Alongside this the strategy has been to increase the weighted average price changes (WAPC) on grandfathered

tariffs compared to the active residential tariffs, particularly the time of use reference tariffs introduced in AA5.

- Small business:
  - Western Power has proposed WAPC on grandfathered tariffs that are not within the tolerance range in line with our strategy to encourage churn onto active tariffs.
- Streetlight tariffs:
  - As requested by the ERA in the 2023-24 Price List determination, a review was 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 proposed price list includes an increase of 5.5 per cent to streetlight asset charges which is the same increase as the 2024-25 and 2025-26 Price List.

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

The following sets out the WAPC for each reference tariff compared with last pricing years reference tariff change forecast.

Table 1.4 – Comparison of 2026-27 weighted average price changes with forecast weighted average price changes from the 2025-26 price list

Reference tariff	WAPC FY26 Price List - FY27 Pricing Year	WAPC FY27 Price List - FY27 Pricing Year	Variance
RT1 – Anytime Energy (Residential)	4.65%	9.86%	5.21%
RT2 – Anytime Energy (Business)	5.95%	9.84%	3.88%
RT3 – Time of Use Energy (Residential)	8.25%	19.74%	11.50%
RT4 – Time of Use Energy (Business)	13.29%	22.71%	9.43%
RT5 – High Voltage Metered Demand	2.59%	8.80%	6.21%
RT6 – Low Voltage Metered Demand	2.61%	8.95%	6.34%
RT7 – High Voltage Contract Maximum Demand	2.59%	9.89%	7.30%
RT8 – Low Voltage Contract Maximum Demand	2.59%	10.86%	8.27%
RT9 – Streetlighting	4.52%	4.92%	0.40%
RT10 – Unmetered Supplies	2.58%	3.80%	1.23%
RT11 – Distribution Entry	3.56%	7.85%	4.29%
RT13 – Anytime Energy (Residential) Bi-directional	4.60%	9.97%	5.37%
RT14 – Anytime Energy (Business) Bi-directional	5.86%	9.46%	3.60%
RT15 – Time of Use (Residential) Bi-directional	8.14%	20.69%	12.55%
RT16 – Time of Use (Business) Bi-directional	14.54%	24.71%	10.17%
RT17 – Time of Use Energy (Residential)	8.21%	22.25%	14.04%

[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 FY26 Price List - FY27 Pricing Year	WAPC FY27 Price List - FY27 Pricing Year	Variance
RT18 – Time of Use Energy (Business)	10.44%	22.23%	11.80%
RT19 – Time of Use Demand (Residential)	9.32%	24.24%	14.92%
RT20 – Time of Use Demand (Business)	15.88%	25.42%	9.54%
RT21 – Multi Part Time of Use Energy (Residential)	8.01%	21.48%	13.47%
RT22 – Multi Part Time of Use Energy (Business)	14.37%	23.46%	9.09%
RT34 – Super Off-peak Time of Use Energy (Business)	5.67%	9.42%	3.76%
RT35 – Super Off-peal Time of Use Energy (Residential)	4.72%	10.17%	5.45%
RT36 – Super Off-peak Time of Use Demand (Business)	5.63%	8.86%	3.24%
RT37 – Super Off-peak Time of Use Demand (Residential)	3.69%	9.72%	6.04%
RT38 – Low Voltage Distribution Storage	2.63%	3.96%	1.33%
RT39 – High Voltage Distribution Storage	2.63%	3.96%	1.33%
RT40 – Low Voltage Electric Vehicle Charging	2.65%	4.05%	1.40%
RT41 – High Voltage Electric Vehicle Charging	2.60%	3.86%	1.26%
Total Bundled Target Revenue from distribution customers	**4.47%**	**9.94%**	**5.47%**
TRT1 - Transmission exit	7.65%	10.79%	3.14%
TRT2 - Transmission entry	7.66%	9.86%	2.20%
TRT3 - Transmission storage	7.68%	10.82%	3.13%
Total Bundled Target Revenue from transmission customers	**7.66%**	**10.39%**	**2.73%**
Total Bundled Target Revenue	**4.67%**	**9.97%**	**5.30%**

There are a number of general factors that have contributed to the difference in the weighted average price change calculated in accordance with the 2026-27 price list compared with the forecast from the 2025-26 price list. The main drivers of the change are an increase in the:

- Gazetted TEC which is not within Western Powers control; and
- Actual CPI higher than forecast (3.8% vs 2.58% originally forecast); and
- Updated customer numbers and usage assumptions within approved categories.

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 2026-27 Price List and the approved demand, customer and energy forecasts as required for compliance with Table 47 of the *access arrangement contract*.

Table 1.5 – Bundled reference service revenue recovered from distribution and transmission connection points for 2026-27 ($M nominal)

Reference tariff	MWh	Customer numbers	Forecast bundled revenue recovered	Average price change
RT1 – Anytime Energy (Residential)	1,528,579	326,783	342.80	9.86%
RT2 – Anytime Energy (Business)	304,861	38,541	83.62	9.84%
RT3 – Time of Use Energy (Residential)^	11,691	1,911	2.85	19.74%
RT4 – Time of Use Energy (Business)^	35,305	903	7.70	22.71%
RT5 – High Voltage Metered Demand	687,933	336	67.93	8.80%
RT6 – Low Voltage Metered Demand	1,613,991	3,795	166.66	8.95%
RT7 – High Voltage Contract Maximum Demand	3,365,150	428	250.51	9.89%
RT8 – Low Voltage Contract Maximum Demand	327,562	32	9.94	10.86%
RT9 – Streetlighting	143,515	307,357	52.26	4.92%
RT10 – Unmetered Supplies	49,452	20,864	7.84	3.80%
RT11 – Distribution Entry	197	26	5.17	7.85%
RT13 – Anytime Energy (Residential) Bi-directional	1,383,978	345,654	337.32	9.97%
RT14 – Anytime Energy (Business) Bi-directional	36,164	2,361	7.78	9.46%
RT15 – Time of Use (Residential) Bi-directional^	25,766	3,140	5.67	20.69%
RT16 – Time of Use (Business) Bi-directional^	11,412	109	2.31	24.71%
RT17 – Time of Use Energy (Residential)*	72,250	3,632	10.68	22.25%
RT18 – Time of Use Energy (Business)*	29,920	1,905	8.50	22.23%
RT19 – Time of Use Demand (Residential)*	9,374	122	1.12	24.24%
RT20 – Time of Use Demand (Business)*	37,379	281	8.34	25.42%
RT21 – Multi Part Time of Use Energy (Residential)*	105,443	7,247	16.75	21.48%
RT22 – Multi Part Time of Use Energy (Business)*	3,560	143	0.89	23.46%
RT34 – Super Off-peak Time of Use Energy (Business)**	1,491,133	75,254	262.64	9.42%
RT35 – Super Off-peal Time of Use Energy (Residential)**	1,134,608	345,159	298.42	10.17%
RT36 – Super Off-peak Time of Use Demand (Business)**	87,549	416	12.23	8.86%
RT37 – Super Off-peak Time of Use Demand (Residential)**	605,952	99,537	115.48	9.72%
RT38 – Low Voltage Distribution Storage**	2,483	19	0.08	3.96%
RT39 – High Voltage Distribution Storage**	0	0	0.00	3.96%
RT40 – Low Voltage Electric Vehicle Charging**	603	49	0.13	4.05%

Reference tariff	MWh	Customer numbers	Forecast bundled revenue recovered	Average price change
RT41 – High Voltage Electric Vehicle Charging**	115	1	0.01	3.86%
Total Bundled Target Revenue distribution customers	**13,105,922**	**1,586,003**	**2,085.62**	**9.94%**
TRT1 - Transmission exit	815	42	65.38	10.79%
TRT2 - Transmission entry	5,475	35	66.57	9.86%
TRT3 - Transmission storage**	1,524	4	20.83	10.82%
Total Bundled Target Revenue transmission customers	**7,813**	**81**	**152.77**	**10.39%**
Total Bundled Target Revenue	**13,113,735**	**1,586,084**	**2,238.39**	**9.97%**

Note: ^ denotes reference tariffs that were closed to new customer nominations on 1 July 2019.
* denotes reference tariffs that were closed to new customer nominations from 1 July 2023.
** denotes reference tariffs introduced in AA5 and were 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	NA5	
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

[5] 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 (RT38 and RT39) 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.

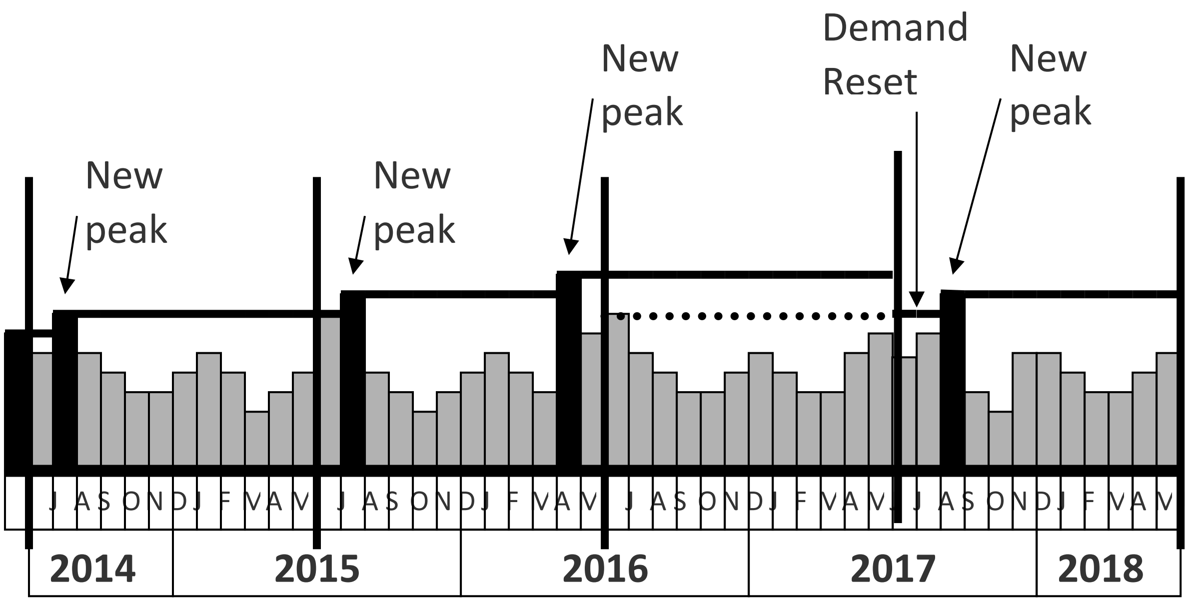
5.3.3 Derivation of rolling 12-month peak

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) which is payable each day;

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);
$DC_{\text{Transmission}}$	are the applicable transmission components of the fixed and variable demand charges for the billing period for the nominated CMD;
$DC_{\text{Distribution}}$	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 8.1 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).

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; 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, 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	131.883	10.908	-	-	-
Reference tariff 2 – RT2	250.075	15.100	-	-	-
Reference tariff 3 – R0T3	131.883	-	28.022	-	6.907
Reference tariff 4 – RT4	457.810	-	33.336	-	8.590
Reference tariff 9 – RT9	8.710	5.887	-	-	-
Reference tariff 10 – RT10	66.227	5.651	-	-	-
Reference tariff 13 – RT13	131.883	10.908	-	-	-
Reference tariff 14 – RT14	250.075	15.100	-	-	-
Reference tariff 15 – RT15	131.883	-	28.022	-	6.907
Reference tariff 16 – RT16	457.810	-	33.336	-	8.590
Reference tariff 17 – RT17	131.883	-	21.460	12.290	8.853
Reference tariff 18 – RT18	260.680	-	36.598	23.311	16.527

Table 8.2: Reference tariffs for RT19 and RT20

Bundled tariff	Fixed Price	Demand	Energy Rates		
	(c/day)	(c/kW/day) or (c/kVA/day)	On-Peak (c/kWh)	Shoulder (c/kWh)	Off-Peak (c/kWh)
Reference tariff 19 – RT19	131.883	9.359	18.551	10.832	7.345
Reference tariff 20 – RT20	313.932	12.051	33.216	19.424	14.083

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

Bundled tariff	Fixed Price	Demand	Energy Rates				
	(c/day)	(c/kW/day) or (c/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	131.883	-	21.381	12.018	8.967	8.967	-
Reference tariff 22 – RT22	250.075	-	36.935	19.890	14.643	14.643	14.643
Reference tariff 34 – RT34	250.075	-	24.710	12.355	9.505	-	6.289
Reference tariff 35 – RT35	131.883	-	19.105	9.553	7.348	-	0.124
Reference tariff 36 – RT36	415.168	8.683	22.424	11.212	8.625	-	6.289
Reference tariff 37 – RT37	131.883	7.165	15.996	7.998	6.152	-	0.124

Table 8.4: Reference tariffs for RT38 and RT39

Bundled tariff	Fixed Price (c/day)	Energy Rates (network to storage - charging)				
		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	0.118	11.420	0.118		22.851
		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)
		0.118	0.118	11.420	22.851	0.118
Bundled tariff	**Fixed Price (c/day)**	**Energy Rates (network to storage - charging)**				
		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	0.118	11.420	0.118		22.851
		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)
		0.118	0.118	11.420	22.851	0.118

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

Capacity of storage works (kVA)	Fixed Price (c/day)
≥ 0 and < 100	413.723
≥100 and < 1,000	827.444
≥1,000 and < 3,000	1,773.096
≥ 3,000	1,773.096

Table 8.6: Reference tariffs for RT40 and RT41

Bundled tariff	Utilisation (%)	Fixed Price (c/day)	Energy Rates				
			Demand On-peak (c/kVA/day)	Off-Peak (c/kWh)	On-Peak (c/kWh)	Shoulder (c/kWh)	Super Off-peak (c/kWh)
Reference tariff 40 – RT40	≥0 & <15	413.723	0.000	7.274	18.912	9.457	4.965
	≥15 & <30	413.723	17.732	3.637	9.457	4.728	3.547
	≥30	413.723	35.462	1.819	4.728	2.365	1.773
Reference tariff 41 – RT41	≥0 & <15	413.723	0.000	7.274	18.912	9.457	4.965
	≥15 & <30	413.723	17.732	3.637	9.457	4.728	3.547
	≥30	413.723	35.462	1.819	4.728	2.365	1.773

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) (c/day)	Daily Charge (Full upfront contribution) (c/day)
42 CFL DECORATIVE	34.031	N/A
42 CFL STANDARD	34.031	N/A
150 HPS STANDARD	38.197	N/A
14 LED DECORATIVE	38.378	12.818
16 LED DECORATIVE	38.378	12.818
18 LED DECORATIVE	38.378	12.818
20 LED DECORATIVE	38.378	12.818
22 LED DECORATIVE	38.378	12.818
27 LED DECORATIVE	38.378	12.818
28 LED DECORATIVE	38.378	12.818
30 LED DECORATIVE	38.378	12.818
43 LED DECORATIVE	38.378	12.818
53 LED DECORATIVE	38.378	12.818
58 LED DECORATIVE	38.378	12.818
80 LED DECORATIVE	38.378	12.818

100 LED DECORATIVE	43.108	12.818
150 LED DECORATIVE	43.108	12.818
170 LED DECORATIVE	43.108	12.818
15 LED STANDARD	17.951	12.818
16 LED STANDARD	17.951	12.818
17 LED STANDARD	17.951	12.818
18 LED STANDARD	17.951	12.818
20 LED STANDARD	17.951	12.818
25 LED STANDARD	17.951	12.818
28 LED STANDARD	17.951	12.818
29 LED STANDARD	17.951	12.818-
33 LED STANDARD	17.951	12.818
36 LED STANDARD	17.951	12.818
37 LED STANDARD	17.951	12.818
42 LED STANDARD	18.095	12.818
43 LED STANDARD	18.095	12.818
53 LED STANDARD	18.095	12.818
59 LED STANDARD	18.095	12.818
70 LED STANDARD	17.921	12.818
78 LED STANDARD	17.921	12.818
80 LED STANDARD	17.921	12.818
89 LED STANDARD	17.921	12.818
112 LED STANDARD	19.661	12.818
118 LED STANDARD	19.661	12.818
122 LED STANDARD	19.661	12.818
135 LED STANDARD	19.661	12.818
140 LED STANDARD	19.661	12.818
141 LED STANDARD	19.661	12.818
143 LED STANDARD	19.661	12.818
165 LED STANDARD	19.661	12.818
170 LED STANDARD	19.661	12.818

Table 8.8: Obsolete light types

Light specification	Daily Charge (No contribution)	Daily Charge (Full upfront contribution)

	(c/day)	(c/day)
70 HPS STANDARD	29.038	N/A
80 HPS STANDARD	29.884	N/A
125 HPS STANDARD	39.311	N/A
250 HPS STANDARD	38.197	N/A
400 HPS STANDARD	39.311	N/A
40 FLU STANDARD	21.616	N/A
100 INC STANDARD	21.616	N/A
70 MH STANDARD	59.040	N/A
80 MH STANDARD	29.095	N/A
150 MH STANDARD	68.210	N/A
250 MH STANDARD	68.210	N/A
42 MV STANDARD	21.616	N/A
50 MV STANDARD	21.616	N/A
70 MV STANDARD	29.095	N/A
80 MV STANDARD	29.095	N/A
125 MV STANDARD	36.171	N/A
150 MV STANDARD	36.171	N/A
250 MV STANDARD	47.185	N/A
400 MV STANDARD	49.542	N/A
17 LED DECORATIVE	36.550	12.818
34 LED DECORATIVE	36.550	12.818
36 LED DECORATIVE	36.550	12.818
42 LED DECORATIVE	33.415	12.818
155 LED DECORATIVE	43.108	12.818
22 LED STANDARD	17.951	12.818
27 LED STANDARD	17.921	12.818
68 LED STANDARD	17.921	12.818
155 LED STANDARD	19.661	12.818
160 LED STANDARD	19.661	12.818

8.2 Prices for demand-based tariffs on the distribution network (RT5 to RT8 and RT11[6])

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	235.541	110.283
300 to 1,000	33,084.900	80.114
1,000 to 1,500	89,164.700	38.390

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	1,359.249	114.894
300 to 1,000	34,468.200	88.518
1,000 to 1,500	96,430.800	46.173

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	68,033.118	38.410	42.426
Forrest Avenue	WFRT	CBD	68,033.118	38.410	42.426
Hay Street	WHAY	CBD	68,033.118	38.410	42.426
Milligan Street	WMIL	CBD	68,033.118	38.410	42.426

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

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)
Wellington Street	WWNT	CBD	68,033.118	38.410	42.426
Black Flag	WBKF	Mining	68,033.118	57.080	58.429
Boulder	WBLD	Mining	68,033.118	53.212	55.113
Bounty	WBNY	Mining	68,033.118	95.147	91.058
West Kalgoorlie	WWKT	Mining	68,033.118	48.249	50.860
Albany	WALB	Mixed	68,033.118	63.590	64.009
Boddington	WBOD	Mixed	68,033.118	38.790	42.752
Bunbury Harbour	WBUH	Mixed	68,033.118	38.271	42.307
Busselton	WBSN	Mixed	68,033.118	48.688	51.234
Byford	WBYF	Mixed	68,033.118	39.998	43.787
Capel	WCAP	Mixed	68,033.118	44.956	48.037
Chapman	WCPN	Mixed	68,033.118	54.910	56.568
Darlington	WDTN	Mixed	68,033.118	42.908	46.281
Durlacher Street	WDUR	Mixed	68,033.118	51.053	53.263
Eneabba	WENB	Mixed	68,033.118	48.889	51.407
Geraldton	WGTN	Mixed	68,033.118	51.053	53.263
Marriott Road	WMRR	Mixed	68,033.118	37.480	41.628
Muchea	WMUC	Mixed	68,033.118	42.683	46.089
Northam	WNOR	Mixed	68,033.118	52.318	54.348
Picton	WPIC	Mixed	68,033.118	40.120	43.892
Rangeway	WRAN	Mixed	68,033.118	53.418	55.290
Sawyers Valley	WSVY	Mixed	68,033.118	49.183	51.661
Yanchep	WYCP	Mixed	68,033.118	42.587	46.006
Yilgarn	WYLN	Mixed	68,033.118	60.395	61.270
Baandee	WBDE	Rural	68,033.118	56.771	58.164
Beenup	WBNP	Rural	68,033.118	60.609	61.454
Bridgetown	WBTN	Rural	68,033.118	39.216	43.117
Carrabin	WCAR	Rural	68,033.118	61.791	62.467
Cataby	WKMC	Rural	68,033.118	40.360	44.098

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)
Collie	WCOE	Rural	68,033.118	45.312	48.342
Coolup	WCLP	Rural	68,033.118	50.319	52.634
Cunderdin	WCUN	Rural	68,033.118	52.724	54.695
Katanning	WKAT	Rural	68,033.118	48.617	51.175
Kellerberrin	WKEL	Rural	68,033.118	55.434	57.018
Kojonup	WKOJ	Rural	68,033.118	35.503	39.934
Kondinin	WKDN	Rural	68,033.118	37.790	41.894
Manjimup	WMJP	Rural	68,033.118	38.948	42.887
Margaret River	WMRV	Rural	68,033.118	48.770	51.307
Merredin	WMER	Rural	68,033.118	50.816	53.061
Moora	WMOR	Rural	68,033.118	39.298	43.187
Mount Barker	WMBR	Rural	68,033.118	50.686	52.947
Narrogin	WNGN	Rural	68,033.118	56.443	57.883
Pinjarra	WPNJ	Rural	68,033.118	29.635	34.904
Regans	WRGN	Rural	68,033.118	40.360	44.098
Three Springs	WTSG	Rural	68,033.118	39.196	43.100
Wagerup	WWGP	Rural	68,033.118	28.511	33.941
Wagin	WWAG	Rural	68,033.118	49.219	51.690
Wundowie	WWUN	Rural	68,033.118	43.723	46.981
Yerbillon	WYER	Rural	68,033.118	60.350	61.232
Amherst	WAMT	Urban	68,033.118	28.576	33.997
Arkana	WARK	Urban	68,033.118	28.576	33.997
Australian Paper Mills	WAPM	Urban	68,033.118	28.576	33.997
Balcatta	WBCT	Urban	68,033.118	28.576	33.997
Beechboro	WBCH	Urban	68,033.118	28.576	33.997
Belmont	WBEL	Urban	68,033.118	28.576	33.997
Bentley	WBTY	Urban	68,033.118	28.576	33.997
Bibra Lake	WBIB	Urban	68,033.118	28.576	33.997
British Petroleum	WBPM	Urban	68,033.118	28.576	33.997

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)
Canning Vale	WCVE	Urban	68,033.118	28.576	33.997
Clarence Street	WCLN	Urban	68,033.118	28.576	33.997
Clarkson	WCKN	Urban	68,033.118	28.576	33.997
Cockburn Cement	WCCT	Urban	68,033.118	28.576	33.997
Collier	WCOL	Urban	68,033.118	28.576	33.997
Cottesloe	WCTE	Urban	68,033.118	28.576	33.997
Edmund Street	WEDD	Urban	68,033.118	28.576	33.997
Forrestfield	WFFD	Urban	68,033.118	28.576	33.997
Gosnells	WGNL	Urban	68,033.118	28.576	33.997
Hadfields	WHFS	Urban	68,033.118	28.576	33.997
Hazelmere	WHZM	Urban	68,033.118	28.576	33.997
Henley Brook	WHBK	Urban	68,033.118	28.576	33.997
Herdsman Parade	WHEP	Urban	68,033.118	28.576	33.997
Joel Terrace	WJTE	Urban	68,033.118	28.576	33.997
Joondalup	WJDP	Urban	68,033.118	28.576	33.997
Kalamunda	WKDA	Urban	68,033.118	28.576	33.997
Kambalda	WKBA	Urban	68,033.118	48.688	51.234
Kewdale	WKDL	Urban	68,033.118	28.576	33.997
Landsdale	WLDE	Urban	68,033.118	28.576	33.997
Maddington	WMDN	Urban	68,033.118	28.576	33.997
Malaga	WMLG	Urban	68,033.118	28.576	33.997
Mandurah	WMHA	Urban	68,033.118	28.576	33.997
Manning Street	WMAG	Urban	68,033.118	28.576	33.997
Mason Road	WMSR	Urban	68,033.118	28.576	33.997
Meadow Springs	WMSS	Urban	68,033.118	28.576	33.997
Medical Centre	WMCR	Urban	68,033.118	28.576	33.997
Medina	WMED	Urban	68,033.118	28.576	33.997
Midland Junction	WMJX	Urban	68,033.118	28.576	33.997
Morley	WMOY	Urban	68,033.118	28.576	33.997

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	68,033.118	28.576	33.997
Mundaring Weir	WMWR	Urban	68,033.118	28.576	33.997
Munday	WMDY	Urban	68,033.118	28.576	33.997
Murdoch	WMUR	Urban	68,033.118	28.576	33.997
Myaree	WMYR	Urban	68,033.118	28.576	33.997
Nedlands	WNED	Urban	68,033.118	28.576	33.997
North Beach	WNBH	Urban	68,033.118	28.576	33.997
North Fremantle	WNFL	Urban	68,033.118	28.576	33.997
North Perth	WNPH	Urban	68,033.118	28.576	33.997
O'Connor	WOCN	Urban	68,033.118	28.576	33.997
Osborne Park	WOPK	Urban	68,033.118	28.576	33.997
Padbury	WPBY	Urban	68,033.118	28.576	33.997
Piccadilly	WPCY	Urban	68,033.118	45.975	48.910
Riverton	WRTN	Urban	68,033.118	28.576	33.997
Rivervale	WRVE	Urban	68,033.118	28.576	33.997
Rockingham	WROH	Urban	68,033.118	28.576	33.997
Shenton Park (Old)	WSPA	Urban	68,033.118	28.576	33.997
Shenton Park (New AA5)	WSPK	Urban	68,033.118	28.576	33.997
Sth Ftle Power Station	WSFT	Urban	68,033.118	28.576	33.997
Southern River	WSNR	Urban	68,033.118	28.576	33.997
Southern Cross	WSNX	Mixed	68,033.118	60.395	61.270
Tate Street	WTTS	Urban	68,033.118	28.576	33.997
University	WUNI	Urban	68,033.118	28.576	33.997
Victoria Park	WVPA	Urban	68,033.118	28.576	33.997
Waikiki	WWAI	Urban	68,033.118	28.576	33.997
Wangara	WWGA	Urban	68,033.118	28.576	33.997
Wanneroo	WWNO	Urban	68,033.118	28.576	33.997
Welshpool	WWEL	Urban	68,033.118	28.576	33.997
Wembley Downs	WWDN	Urban	68,033.118	28.576	33.997

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)
Willetton	WWLN	Urban	68,033.118	28.576	33.997
Yokine	WYKE	Urban	68,033.118	28.576	33.997

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	2.178	1.538
Mining	0.466	0.326
Mixed	1.017	0.702
Rural	0.633	0.441

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	1.865	1.309
Mining	0.403	0.281
Mixed	0.875	0.607
Rural	0.549	0.377

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[7].

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[8]

Reference Tariff	(c/revenue meter/day)
RT1	11.886
RT2	12.545
RT3	12.359
RT4	19.494
RT5 – RT8	21.492
RT11	21.492
RT13	11.886
RT14	12.545
RT15	12.359
RT16	19.494
RT17	21.492
RT18	21.492
RT19	21.492
RT20	21.492
RT21	21.492
RT22	21.492
RT34	12.545
RT35	11.886
RT36	12.545
RT37	11.886
RT38	21.492
RT39	21.492

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

8 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)
RT40	21.492
RT41	21.492
TRT1, TRT2 and TRT3	1,211.979

Table 8.15: Metering reference service prices

Metering Reference Service	(c/revenue meter/day)
M1	3.613
M2	3.613
M3	41.244
M4	82.490
M5	22.039
M6	22.039
M7 - SIM	191.058
M7 - AMI	3.613
M8	3.613
M9	3.613
M10	41.244
M11	82.490
M12	22.039
M13	22.039
M14 - SIM	191.058
M14 - AMI	3.613
M15	-
M17	991.603
M18	97.451
M19	991.603
M20	97.451

Table 8.16: Metering reference service prices

Metering Reference Service	Charge per site visit ($)
M16	25.246

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	6,758.157
>=7,000 kVA	11,770.090

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 (c/day)	Demand (c/kVA/day)
RT8	1,407.495	13.723

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	2.003

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	24.123
Alcoa Pinjarra	WAPJ	6.842
Amherst	WAMT	5.742
Arkana	WARK	7.329
Australian Fused Materials	WAFM	4.759
Australian Paper Mills	WAPM	7.420
Baandee (WC)	WBDE	25.857
Balcatta	WBCT	7.509
Beckenham	WBEC	18.944

Substation	TNI	Use of System Price (c/kW/day)
Beechboro	WBCH	6.669
Beenup	WBNP	28.929
Belmont	WBEL	5.909
Bentley	WBTY	7.693
Bibra Lake	WBIB	5.282
Binningup Desalination Plant	WBDP	4.081
Black Flag	WBKF	26.367
Boddington	WBOD	4.313
Boddington Gold Mine	WBGM	4.426
Boulder	WBLD	23.243
Bounty	WBNY	57.102
Bridgetown	WBTN	11.814
British Petroleum	WBPM	10.201
Broken Hill Kwinana	WBHK	7.960
Bunbury Harbour	WBUH	3.902
Busselton	WBSN	12.219
Byford	WBYF	5.280
Canning Vale	WCVE	6.038
Capel	WCAP	9.240
Carrabin	WCAR	29.871
Cataby Kerr McGee	WKMC	11.019
Chapman	WCPN	17.190
Clarence Street	WCLN	9.922
Clarkson	WCKN	7.482
Cockburn Cement	WCCT	4.147
Cockburn Cement Ltd	WCCL	4.135
Collie	WCOE	16.691
Collier	WCOL	9.875
Cook Street	WCKT	7.104
Coolup	WCLP	20.696
Cottesloe	WCTE	7.695
Cunderdin	WCUN	22.622
Darlington	WDTN	7.606

Substation	TNI	Use of System Price (c/kW/day)
Edgewater	WEDG	6.589
Edmund Street	WEDD	6.779
Eneabba	WENB	12.378
Forrest Ave	WFRT	9.935
Forrestfield	WFFD	7.788
Geraldton	WGTN	14.108
Glen Iris	WGNI	4.603
Golden Grove	WGGV	36.978
Gosnells	WGNL	6.269
Hadfields	WHFS	7.534
Hay Street	WHAY	7.534
Hazelmere	WHZM	5.839
Henley Brook	WHBK	6.437
Herdsman Parade	WHEP	11.425
Joel Terrace	WJTE	10.371
Joondalup	WJDP	7.062
Kalamunda	WKDA	7.957
Katanning	WKAT	19.336
Kellerberrin	WKEL	24.790
Kewdale	WKDL	5.794
Kojonup	WKOJ	8.847
Kondinin	WKDN	10.677
Kwinana Alcoa	WAKW	1.830
Kwinana Desalination Plant	WKDP	5.025
Kwinana PWS	WKPS	3.670
Landsdale	WLDE	6.791
Maddington	WMDN	6.102
Malaga	WMLG	5.799
Mandurah	WMHA	4.982
Manjimup	WMJP	11.601
Manning Street	WMAG	8.434
Margaret River	WMRV	19.460
Marriott Road	WMRR	3.269

Substation	TNI	Use of System Price (c/kW/day)
Marriott Road Barrack Silicon Smelter	WBSI	3.731
Mason Road	WMSR	2.914
Mason Road CSBP	WCBP	4.406
Mason Road Kerr McGee	WKMK	2.669
Meadow Springs	WMSS	5.650
Medical Centre	WMCR	8.938
Medina	WMED	4.207
Merredin 66kV	WMER	21.095
Midland Junction	WMJX	7.099
Milligan Street	WMIL	8.414
Moora	WMOR	11.882
Morley	WMOY	7.740
Mt Barker	WMBR	20.992
Muchea	WMUC	7.423
Muchea Kerr McGee	WKMM	11.210
Muja PWS	WMPS	2.231
Mullaloo	WMUL	7.295
Mundaring Weir	WMWR	11.388
Munday	WMDY	7.863
Murdoch	WMUR	4.703
Myaree	WMYR	8.984
Narrogin	WNGN	25.593
Nedlands	WNED	8.413
North Beach	WNBH	7.509
North Fremantle	WNFL	7.552
North Perth	WNPH	6.410
Northam	WNOR	15.118
Nowgerup	WNOW	8.662
O'Connor	WOCN	7.836
Osborne Park	WOPK	8.144
Padbury	WPBY	7.607
Parkeston	WPRK	26.460
Parklands	WPLD	5.807

Substation	TNI	Use of System Price (c/kW/day)
Piccadilly	WPCY	21.042
Picton 66kv	WPIC	5.378
Pinjarra	WPNJ	4.153
Rangeway	WRAN	16.000
Regans	WRGN	12.730
Riverton	WRTN	5.199
Rivervale	WRVE	8.083
Rockingham	WROH	4.454
Sawyers Valley	WSVY	12.617
Shenton Park	WSPA	8.752
South Fremantle 22kV	WSFT	5.659
Southern River	WSNR	5.458
Summer St	WSUM	10.703
Sutherland	WSRD	6.410
Tate Street	WTTS	9.038
Three Springs	WTSG	11.801
Three Springs Terminal (Karara)	WTST	28.498
Tomlinson Street	WTLN	9.156
University	WUNI	9.704
Victoria Park	WVPA	8.837
Wagerup	WWGP	3.254
Wagin	WWAG	19.817
Waikiki	WWAI	4.869
Wangara	WWGA	6.973
Wanneroo	WWNO	7.338
Wellington Street	WWNT	10.650
Welshpool	WWEL	5.759
Wembley Downs	WWDN	8.593
West Kalgoorlie	WWKT	19.235
Western Collieries	WWCL	3.275
Western Mining	WWMG	3.850
Westralian Sands	WWSD	8.377
Willetton	WWLN	5.533

Substation	TNI	Use of System Price (c/kW/day)
Worsley	WWOR	2.717
Wundowie	WWUN	15.422
Yanchep	WYCP	7.349
Yerbillon	WYER	28.722
Yilgarn	WYLN	21.573
Yokine	WYKE	7.959

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	3.093
Alcoa Pinjarra	WAPJ	2.749
Badgingarra	WBGA	3.153
Bluewaters	WBWP	3.112
Boulder	WBLD	2.239
Cockburn PWS	WCKB	1.887
Collgar	WCGW	3.571
Collie PWS	WCPS	3.619
Cunderin Solar Farm	WCSF	2.599
Emu Downs	WEMD	3.153
Geraldton	WGTN	0.529
Greenough Solar Farm	TMGS	0.674
Kemerton PWS	WKEM	2.515
Kwinana Alcoa	WAKW	1.946
Kwinana BESS	WKWB	1.887
Kwinana Donaldson Road	WKND	1.479
Kwinana PWS	WKPS	1.887
Kwinana Waste to Energy	WKWW	1.479
Landwehr (Alinta)	WLWT	2.347
Mason Road	WMSR	1.479
Merredin Power Station	TMDP	2.599
Merredin Solar Farm	WMSF	2.599

Substation	TNI	Use of System Price (c/kW/day)
Muja PWS	WMPS	3.798
Mumbida Wind Farm	TMBW	3.200
Mungarra GTs	WMGA	3.144
Neoen Collie BESS	WPMB	3.619
Newgen Kwinana	WNGK	2.195
Newgen Neerabup	WGNN	1.933
Oakley (Alinta)	WOLY	2.617
Parkeston	WPKS	2.699
Pinjar GTs	WPJR	1.569
Synergy Collie BESS	WCBB	3.619
Tiwest GT	WKMK	1.524
Wagerup	WWGP	2.164
Walkaway Windfarm	WWWF	3.471
Warradarge Wind Farm	WWDW	3.153
West Kalgoorlie GTs	WWKT	2.195
Worsley	WWOR	2.457
Yandin Wind Farm	WYDW	1.933

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	7.204

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)	0.305

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)	2.703

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[9]	524.177
Whole current meters non-Metropolitan area	667.661
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	6.432
RT29	6.432

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

[9] As defined in the Electricity Industry (Metering) Code

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	22.423	27.562	38.924
	AMS urgent	89.832	133.019	180.984
RT32	Standard	72.824	72.824	72.824
RT33	Standard	72.803	72.803	72.803
	Urgent	183.739	183.739	183.739

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 >=30kVA to <=200 kVA	$250.00
Enquiry Fee >200 kVA	$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)	$6.432 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
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 2026-27 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 2026-27 ($M Nominal)

Reference Service	Reference Tariff	Avoidable Cost	Stand-alone Cost	Forecast Revenue Recovered from Reference Tariff
A1	RT1	45.82	1,067.12	342.80
A2	RT2	10.38	893.22	83.62
A3	RT3	0.34	846.84	2.85
A4	RT4	1.70	852.77	7.70
A5, C5	RT5	7.04	604.36	67.93
A6, C6	RT6	21.42	946.95	166.66
A7, C7	RT7	39.43	757.86	250.51
A8, C8	RT8	1.07	850.32	9.94
A9	RT9	0.13	846.65	52.26
A10	RT10	1.31	851.46	7.84
B1	RT11	0.91	849.38	5.17
C1	RT13	56.10	1,113.70	337.32
C2	RT14	0.99	849.72	7.78
C3	RT15	0.65	848.30	5.67
C4	RT16	0.44	847.18	2.31
A12, C9	RT17	0.83	849.14	10.68
A13, C10	RT18	1.78	853.21	8.50
A14, C11	RT19	0.19	846.09	1.12
A15, C12	RT20	0.95	849.44	8.34
A16, C13	RT21	4.35	864.93	16.75
A17, C14	RT22	0.13	845.82	0.89
A19, C17	RT34	61.16	1,118.82	262.64

Reference Service	Reference Tariff	Avoidable Cost	Stand-alone Cost	Forecast Revenue Recovered from Reference Tariff
A18, C16	RT35	62.46	1,141.87	298.42
A21, C19	RT36	0.34	846.75	12.23
A20, C18	RT37	18.01	930.78	115.48
C23	RT38	0.02	845.31	0.08
C24	RT39	-	570.97	0.00
A22, C20	RT40	0.06	845.52	0.13
A23, C21	RT41	-	570.97	0.01
A11	TRT1	2.39	469.73	65.38
B2	TRT2	2.39	103.78	66.57
C22	TRT3	2.39	97.67	20.83

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 2026-27 ($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	501.58	406.76	56.58	79.59	0.00	187.84	1,232.35	206.47	1,232.35	55.06%
LV business - small	248.55	208.40	23.38	8.59	0.00	20.26	509.18	72.23	509.18	22.75%
LV business - large	83.29	8.69	8.18	0.28	0.00	0.66	101.10	13.85	101.10	4.52%
HV business	165.68	17.28	14.46	0.06	0.00	0.15	197.64	54.92	197.64	8.83%

Streetlights	0.00	0.45	0.00	0.00	34.04	5.13	39.62	6.73	39.62	1.77%
Unmetered	0.82	1.92	0.09	0.00	0.00	2.90	5.74	1.20	5.74	0.26%
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	152.77	152.77	6.83%
Total	**999.93**	**643.50**	**102.70**	**88.52**	**34.04**	**216.93**	**2,085.62**	**508.16**	**2,238.39**	**100.00%**

Distribution revenue of $2,086 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 2026-27 ($M nominal)

Reference tariff	MWh	Customer numbers	Forecast bundled revenue recovered
RT1 – Anytime Energy (Residential)	1,528,579	326,783	342.80
RT2 – Anytime Energy (Business)	304,861	38,541	83.62
RT3 – Time of Use Energy (Residential)	11,691	1,911	2.85
RT4 – Time of Use Energy (Business)	35,305	903	7.70
RT5 – High Voltage Metered Demand	687,933	336	67.93
RT6 – Low Voltage Metered Demand	1,613,991	3,795	166.66
RT7 – High Voltage Contract Maximum Demand	3,365,150	428	250.51

Reference tariff	MWh	Customer numbers	Forecast bundled revenue recovered
RT8 – Low Voltage Contract Maximum Demand	327,562	32	9.94
RT9 – Streetlighting	143,515	307,357	52.26
RT10 – Unmetered Supplies	49,452	20,864	7.84
RT11 – Distribution Entry	197	26	5.17
RT13 – Anytime Energy (Residential) Bi-directional	1,383,978	345,654	337.32
RT14 – Anytime Energy (Business) Bi-directional	36,164	2,361	7.78
RT15 – Time of Use (Residential) Bi-directional	25,766	3,140	5.67
RT16 – Time of Use (Business) Bi-directional	11,412	109	2.31
RT17 – Time of Use Energy (Residential)	72,250	3,632	10.68
RT18 – Time of Use Energy (Business)	29,920	1,905	8.50
RT19 – Time of Use Demand (Residential)	9,374	122	1.12
RT20 – Time of Use Demand (Business)	37,379	281	8.34
RT21 – Multi Part Time of Use Energy (Residential)	105,443	7,247	16.75
RT22 – Multi Part Time of Use Energy (Business)	3,560	143	0.89
RT34 – Super Off-peak Time of Use Energy (Business)	1,491,133	75,254	262.64
RT35 – Super Off-peal Time of Use Energy (Residential)	1,134,608	345,159	298.42
RT36 – Super Off-peak Time of Use Demand (Business)	87,549	416	12.23
RT37 – Super Off-peak Time of Use Demand (Residential)	605,952	99,537	115.48
RT38 – Low Voltage Distribution Storage	2,483	19	0.08
RT39 – High Voltage Distribution Storage	0	0	0.00
RT40 – Low Voltage Electric Vehicle Charging	603	49	0.13
RT41 – High Voltage Electric Vehicle Charging	115	1	0.01
Total Bundled Target Revenue from distribution customers	**13,105,922**	**1,586,003**	**2,085.62**
TRT1 - Transmission exit	815	42	65.38
TRT2 - Transmission entry	5,475	35	66.57
TRT3 - Transmission storage	1,524	4	20.83
Total Bundled Target Revenue from transmission customers	**7,813**	**81**	**152.77**
Total Bundled Target Revenue	**13,113,735**	**1,586,084**	**2,238.39**

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 2026-27 tariffs exceeds the avoidable cost calculated for the comparison of stand-alone and avoidable costs above.

Table A.4 Demonstration that variable costs exceed avoidable costs of reference tariff provision for 2026-27 ($M nominal)

Reference Service	Reference Tariff	Avoidable Cost	Variable tariff components
A1	RT1	45.82	171.31
A2	RT2	10.38	46.68
A3	RT3	0.34	1.84
A4	RT4	1.70	6.12
A5, C5	RT5	7.04	27.01
A6, C6	RT6	21.42	108.89
A7, C7	RT7	39.43	140.31
A8, C8	RT8	1.07	1.04
A9	RT9	0.13	8.45
A10	RT10	1.31	2.79
B1	RT11	0.91	5.17
C1	RT13	56.10	155.94
C2	RT14	0.99	5.52
C3	RT15	0.65	4.02
C4	RT16	0.44	2.12
A12, C9	RT17	0.83	8.64
A13, C10	RT18	1.78	6.54
A14, C11	RT19	0.19	1.06
A15, C12	RT20	0.95	7.99
A16, C13	RT21	4.35	12.69
A17, C14	RT22	0.13	0.75
A19, C17	RT34	61.16	190.51
A18, C16	RT35	62.46	117.29
A21, C19	RT36	0.34	11.58

Reference Service	Reference Tariff	Avoidable Cost	Variable tariff components
A20, C18	RT37	18.01	63.24
C23	RT38	0.02	0.04
C24	RT39	0.00	0.00
A22, C20	RT40	0.06	0.06
A23, C21	RT41	0.00	0.01

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.

A.1.4.1 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 2026-27.

A.2.1 Transmission pricing cost pools

The following sets out the allocation of revenue to the transmission cost pools for the 2026-27 pricing year.

Table A.5 - Transmission Pricing Cost Pools for 2026-27 ($M Nominal)

Cost Pool	Allocated Revenue
Entry connection	13.77
Exit connection HV	3.37
Exit connection LV	131.48
CSS entry	6.28
CSS exit	45.31
UOS entry	51.18
UOS exit	142.09
Common service	114.40
Metering CT/VT	0.29
Total	**508.16**

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 2026-27 ($M Nominal)

Cost Pool	Locational Zone					
	CBD	Urban	Mining	Mixed	Rural	Total
High Voltage Network	6.77	236.37	12.12	297.67	446.99	999.93
Low Voltage Network	8.01	414.81	0.32	150.73	69.64	643.50
Transformers	3.01	48.08	0.35	28.57	22.70	102.70
Streetlight Assets	0.90	35.45	0.65	24.18	27.34	88.52
Metering	0.35	13.63	0.25	9.30	10.51	34.04
Administration	2.21	86.87	1.59	59.26	67.00	216.93
Revenue requirement	**21.24**	**835.21**	**15.27**	**569.71**	**644.18**	**2,085.62**

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

2026-27 cost of service	Streetlights	Metering
Opening RAB	102.18	430.16
Return on asset	7.80	18.45
Depreciation	11.90	40.77
Opex	20.00	23.97
Indirect cost allocation	-	5.31
Cost of service	**39.70**	**88.50**

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 FY27 price list, the smoothed target revenue used was $34 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 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	Annual change FY24 to FY25	Annual change FY25 to FY26	Baseline $/year FY26	Annual change FY26 to FY27	Baseline $/year FY27
Low consumption end-user	0%	5%	11%	9%	672	10%	742
Medium consumption end-user	0%	4%	10%	9%	817	10%	899
High consumption end-user	0%	3%	9%	9%	981	10%	1,077

Representative end-user	Annual change FY22 to FY23	Annual change FY23 to FY24	Annual change FY24 to FY25	Annual change FY25 to FY26	Baseline $/year FY26	Annual change FY26 to FY27	Baseline $/year FY27
Typical solar end-user	0%	3%	10%	9%	885	10%	973
Typical non-solar end-user	0%	4%	10%	9%	806	10%	887

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	Annual change FY24 to FY25	Annual change FY25 to FY26	Baseline $/year FY26	Annual change FY26 to FY27	Baseline $/year FY27
Low consumption end-user	0%	12%	12%	11%	743	16%	861
Medium consumption end-user	0%	14%	11%	12%	938	18%	1,106
High consumption end-user	0%	14%	11%	12%	1,154	19%	1,377
Typical solar end-user	0%	14%	11%	12%	989	18%	1,170
Typical non-solar end-user	0%	13%	11%	12%	923	18%	1,086

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	Annual change FY24 to FY25	Annual change FY25 to FY26	Baseline $/year FY26	Annual change FY26 to FY27	Baseline $/year FY27
Low consumption end-user	0%	9%	12%	11%	697	15%	802
Medium consumption end-user	0%	11%	11%	11%	834	17%	974

Representative end-user	Annual change FY22 to FY23	Annual change FY23 to FY24	Annual change FY24 to FY25	Annual change FY25 to FY26	Baseline $/year FY26	Annual change FY26 to FY27	Baseline $/year FY27
High consumption end-user	0%	12%	10%	12%	989	18%	1,167
Typical solar end-user	0%	12%	11%	11%	909	17%	1,067
Typical non-solar end-user	0%	11%	11%	11%	824	17%	961

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	Annual change FY24 to FY25	Annual change FY25 to FY26	Baseline $/year FY26	Annual change FY26 to FY27	Baseline $/year FY27
Low consumption end-user	0%	13%	22%	11%	773	9%	845
Medium consumption end-user	0%	14%	19%	11%	905	12%	1,009
High consumption end-user	0%	15%	17%	12%	1,047	13%	1,187
Typical solar end-user	0%	14%	19%	11%	969	12%	1,090
Typical non-solar end-user	0%	14%	19%	11%	893	11%	995

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	Annual change FY24 to FY25	Annual change FY25 to FY26	Baseline $/year FY26	Annual change FY26 to FY27	Baseline $/year FY27
Low consumption end-user	0%	12%	12%	11%	723	15%	833

Representative end-user	Annual change FY22 to FY23	Annual change FY23 to FY24	Annual change FY24 to FY25	Annual change FY25 to FY26	Baseline $/year FY26	Annual change FY26 to FY27	Baseline $/year FY27
Medium consumption end-user	0%	14%	12%	11%	884	17%	1,034
High consumption end-user	0%	15%	11%	12%	1,065	18%	1,262
Typical solar end-user	0%	14%	12%	12%	967	18%	1,139
Typical non-solar end-user	0%	14%	12%	11%	872	17%	1,019

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	Annual change FY24 to FY25	Annual change FY25 to FY26	Baseline $/year FY26	Annual change FY26 to FY27	Baseline $/year FY27
Low consumption end-user		0%	11%	9%	651	10%	720
Medium consumption end-user		0%	10%	9%	780	10%	859
High consumption end-user		0%	9%	9%	926	10%	1,017
Typical solar end-user		0%	10%	9%	898	10%	987
Typical non-solar end-user		0%	10%	9%	770	10%	849

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	Annual change FY24 to FY25	Annual change FY25 to FY26	Baseline $/year FY26	Annual change FY26 to FY27	Baseline $/year FY27
Low consumption end-user		0%	14%	9%	654	10%	722
Medium consumption end-user		0%	15%	9%	775	10%	853
High consumption end-user		0%	15%	9%	906	10%	996
Typical solar end-user		0%	15%	9%	875	10%	962
Typical non-solar end-user		0%	15%	9%	764	10%	842

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	Annual change FY24 to FY25	Annual change FY25 to FY26	Baseline $/year FY26	Annual change FY26 to FY27	Baseline $/year FY27
Low consumption end-user	0%	6%	12%	9%	1,126	11%	1,245

Representative end-user	Annual change FY22 to FY23	Annual change FY23 to FY24	Annual change FY24 to FY25	Annual change FY25 to FY26	Baseline $/year FY26	Annual change FY26 to FY27	Baseline $/year FY27
Medium consumption end-user	0%	5%	11%	9%	1,592	10%	1,752
High consumption end-user	0%	3%	9%	9%	2,393	10%	2,623
Typical solar end-user	0%	3%	9%	9%	2,314	10%	2,537
Typical non-solar end-user	0%	3%	9%	9%	2,728	10%	2,987

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	Annual change FY24 to FY25	Annual change FY25 to FY26	Baseline $/year FY26	Annual change FY26 to FY27	Baseline $/year FY27
Low consumption end-user	0%	7%	12%	12%	1,930	13%	2,187
Medium consumption end-user	0%	9%	11%	15%	2,538	16%	2,954
High consumption end-user	0%	11%	10%	18%	3,652	19%	4,360
Typical solar end-user	0%	11%	11%	17%	3,171	18%	3,754
Typical non-solar end-user	0%	12%	10%	18%	3,974	20%	4,766

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	Annual change FY24 to FY25	Annual change FY25 to FY26	Baseline $/year FY26	Annual change FY26 to FY27	Baseline $/year FY27
Low consumption end-user	0%	9%	19%	13%	1,276	15%	1,462
Medium consumption end-user	0%	11%	16%	17%	1,861	18%	2,199
High consumption end-user	0%	13%	14%	21%	2,891	21%	3,499
Typical solar end-user	0%	13%	15%	20%	2,768	21%	3,343
Typical non-solar end-user	0%	14%	14%	21%	3,267	22%	3,974

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	Annual change FY24 to FY25	Annual change FY25 to FY26	Baseline $/year FY26	Annual change FY26 to FY27	Baseline $/year FY27
Low consumption end-user	0%	15%	10%	12%	1,492	15%	1,709
Medium consumption end-user	0%	16%	10%	14%	2,036	18%	2,395
High consumption end-user	0%	16%	10%	17%	2,987	20%	3,595
Typical solar end-user	0%	16%	11%	16%	2,849	20%	3,421
Typical non-solar end-user	0%	16%	10%	17%	3,314	21%	4,007

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	Annual change FY24 to FY25	Annual change FY25 to FY26	Baseline $/year FY26	Annual change FY26 to FY27	Baseline $/year FY27
Low consumption end-user	0%	8%	12%	13%	1,227	15%	1,405
Medium consumption end-user	0%	10%	11%	16%	1,800	18%	2,128
High consumption end-user	0%	12%	10%	19%	2,818	21%	3,412
Typical solar end-user	0%	12%	11%	19%	2,657	21%	3,210
Typical non-solar end-user	0%	12%	10%	19%	3,174	22%	3,862

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	Annual change FY24 to FY25	Annual change FY25 to FY26	Baseline $/year FY26	Annual change FY26 to FY27	Baseline $/year FY27
Low consumption end-user		0%	15%	9%	1,102	10%	1,212
Medium consumption end-user		0%	13%	9%	1,491	10%	1,635
High consumption end-user		0%	11%	9%	2,157	9%	2,359
Typical solar end-user		0%	11%	9%	2,250	9%	2,460
Typical non-solar end-user		0%	11%	9%	2,440	9%	2,666

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	Annual change FY24 to FY25	Annual change FY25 to FY26	Baseline $/year FY26	Annual change FY26 to FY27	Baseline $/year FY27
Low consumption end-user		0%	7%	9%	1,690	11%	1,878
Medium consumption end-user		0%	8%	9%	2,078	11%	2,300
High consumption end-user		0%	8%	9%	2,738	10%	3,017
Typical solar end-user		0%	8%	9%	2,779	10%	3,062
Typical non-solar end-user		0%	8%	9%	2,999	10%	3,301

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 2026-27 ($M Nominal)

Reference Tariff	MWh	Number Customers	Forecast TEC Recovered
RT1 - Anytime Energy (Residential)	1,528,579	326,783	39.62
RT2 - Anytime Energy (Business)	304,861	38,541	8.08

Reference Tariff	MWh	Number Customers	Forecast TEC Recovered
RT3 - Time of Use Energy (Residential)	11,691	1,911	0.25
RT4 - Time of Use Energy (Business)	35,305	903	0.73
RT5 - High Voltage Metered Demand	687,933	336	22.30
RT6 - Low Voltage Metered Demand	1,613,991	3,795	46.00
RT7 - High Voltage Contract Maximum Demand	3,365,150	428	13.09
RT8 - Low Voltage Contract Maximum Demand	327,562	32	1.03
RT9 – Streetlighting	143,515	307,357	1.46
RT10 - Unmetered Supplies	49,452	20,864	0.53
RT11 - Distribution Entry	197	26	Not Applicable
RT13 – Anytime Energy (Residential) Bi-directional	1,383,978	345,654	35.87
RT14 – Anytime Energy (Business) Bi-directional	36,164	2,361	0.96
RT15 – Time of Use (Residential) Bi-directional	25,766	3,140	0.56
RT16 – Time of Use (Business) Bi-directional	11,412	109	0.25
RT17 - Time of Use Energy (Residential)	72,250	3,632	1.79
RT18 - Time of Use Energy (Business)	29,920	1,905	0.76
RT19 – Time of Use Demand (Residential)	9,374	122	0.22
RT20 – Time of Use Demand (Business)	37,379	281	0.92
RT21 – Multi Part Time of Use Energy (Residential)	105,443	7,247	2.61
RT22 – Multi Part Time of Use Energy (Business)	3,560	143	0.09
RT34 – Super Off-peak Time of Use Energy (Business)	1,491,133	75,254	37.16
RT35 – Super Off-peal Time of Use Energy (Residential)	1,134,608	345,159	22.33
RT36 – Super Off-peak Time of Use Demand (Business)	87,549	416	2.21
RT37 – Super Off-peak Time of Use Demand (Residential)	605,952	99,537	12.13
RT40 – Low Voltage Electric Vehicle Charging	603	49	0.00
RT41 – High Voltage Electric Vehicle Charging	115	1	0.00
Total			**251.00**

A.5. Price Changes per Tariff Component

This section shows the percentage changes applied to each tariff component.

A.5.1 Prices for energy-based tariffs on the distribution network

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 A.5.3: 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	11.19%	8.42%			
Reference tariff 2 - RT2	11.19%	8.73%			
Reference tariff 3 - RT3	11.19%		25.27%		25.26%
Reference tariff 4 - RT4	11.19%		26.17%		26.18%
Reference tariff 9 – RT9	3.80%	3.81%			
Reference tariff 10 – RT10	3.81%	3.80%			
Reference tariff 13 - RT13	11.19%	8.42%			
Reference tariff 14 - RT14	11.19%	8.73%			
Reference tariff 15 - RT15	11.19%		25.27%		25.26%
Reference tariff 16 - RT16	11.19%		26.17%		26.18%
Reference tariff 17 - RT17	11.19%		25.27%	25.27%	25.27%
Reference tariff 18 - RT18	11.19%		26.17%	26.17%	26.17%

Table A.5.4: Reference tariffs for RT19 and RT20

Bundled tariff	Fixed Price	Demand	Energy Rates		
	(c/day)	(c/kW/day) or (c/kVA/day)	On-Peak (c/kWh)	Shoulder (c/kWh)	Off-Peak (c/kWh)
Reference tariff 19 – RT19	11.19%	25.27%	25.27%	25.27%	25.28%
Reference tariff 20 - RT20	11.19%	26.18%	26.17%	26.17%	26.17%

Table A.5.5: Reference tariffs for RT21, RT22, RT34, RT35, RT36 and RT37

Bundled tariff	Fixed Price	Demand	Energy Rates				
	(c/day)	(c/kW/day) or (c/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	11.19%		25.27%	25.27%	25.27%	25.27%	
Reference tariff 22 – RT22	11.19%		26.17%	26.17%	26.17%	26.17%	26.17%
Reference tariff 34 – RT34	11.19%		8.73%	8.72%	8.73%		8.73%
Reference tariff 35 – RT35	11.19%		8.42%	8.42%	8.41%		8.77%
Reference tariff 36 – RT36	11.19%	8.73%	8.72%	8.72%	8.72%		8.73%
Reference tariff 37 – RT37	11.19%	8.43%	8.43%	8.42%	8.41%		8.77%

Table A.5.6: Reference tariffs for RT38 and RT39

<table>
<tr><th rowspan="2">Bundled tariff</th><th>Fixed Price</th><th colspan="5">Energy Rates (network to storage - charging)</th></tr>
<tr><th>(c/day)</th><th>Off-Peak (c/kWh)</th><th>Shoulder (c/kWh)</th><th colspan="2">Super Off-Peak (c/kWh)</th><th>On-Peak (c/kWh)</th></tr>
<tr><td rowspan="4">Reference tariff 38 – RT38</td><td rowspan="4">Varies with capacity see Table 8.5 below</td><td>3.51%</td><td>3.81%</td><td colspan="2">3.51%</td><td>3.81%</td></tr>
<tr><th colspan="5">Energy Rates (storage to network – discharging)</th></tr>
<tr><th>Off-Peak (c/kWh)</th><th>Shoulder (c/kWh)</th><th>Super Off-peak 0-3 kWh (c/kWh)</th><th>Super Off-Peak > 3 kWh (c/kWh)</th><th>On-Peak (c/kWh)</th></tr>
<tr><td>3.51%</td><td>3.51%</td><td>3.81%</td><td>3.81%</td><td>3.51%</td></tr>
<tr><th rowspan="2">Bundled tariff</th><th>Fixed Price</th><th colspan="5">Energy Rates (network to storage - charging)</th></tr>
<tr><th>(c/day)</th><th>Off-Peak (c/kWh)</th><th>Shoulder (c/kWh)</th><th colspan="2">Super Off-Peak (c/kWh)</th><th>On-Peak (c/kWh)</th></tr>
<tr><td rowspan="4">Reference tariff 39 – RT39</td><td rowspan="4">Varies with capacity see Table 8.5 below</td><td>3.51%</td><td>3.81%</td><td colspan="2">3.51%</td><td>3.81%</td></tr>
<tr><th colspan="5">Energy Rates (storage to network - discharging)</th></tr>
<tr><th>Off-Peak (c/kWh)</th><th>Shoulder (c/kWh)</th><th>Super Off-peak 0-3 kWh (c/kWh)</th><th>Super Off-Peak > 3 kWh (c/kWh)</th><th>On-Peak (c/kWh)</th></tr>
<tr><td>3.51%</td><td>3.51%</td><td>3.51%</td><td>3.51%</td><td>3.51%</td></tr>
</table>

Table A.5.7: Fixed Price for Reference tariffs for RT38 and RT39

Capacity of storage works (kVA)	Fixed Price (c/day)
≥ 0 and < 100	3.80%
≥100 and < 1,000	3.80%
≥1,000 and < 3,000	3.80%
≥ 3,000	3.80%

Table A.5.8: Reference tariffs for RT40 and RT41

Bundled tariff	Utilisation (%)	Fixed Price (c/day)	Energy Rates				
			Demand On-peak (c/kVA/day)	Off-Peak (c/kWh)	On-Peak (c/kWh)	Shoulder (c/kWh)	Super Off-peak (c/kWh)
Reference tariff 40 – RT40	≥0 & <15	3.80%		3.81%	3.80%	3.81%	3.81%
	≥15 & <30	3.80%	3.81%	3.80%	3.81%	3.80%	3.80%
	≥30	3.80%	3.81%	3.82%	3.80%	3.82%	3.81%
Reference tariff 41 – RT41	≥0 & <15	3.80%		3.81%	3.80%	3.81%	3.81%
	≥15 & <30	3.80%	3.81%	3.80%	3.81%	3.80%	3.80%
	≥30	3.80%	3.81%	3.82%	3.80%	3.82%	3.81%

Streetlight asset prices

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

Table A.5.9: Current light types

Light specification	Daily Charge (No contribution) (c/day)	Daily Charge (Full upfront contribution) (c/day)
42 CFL DECORATIVE	5.53%	N/A
42 CFL STANDARD	5.53%	N/A
150 HPS STANDARD	5.53%	N/A
14 LED DECORATIVE	5.53%	5.53%
16 LED DECORATIVE	5.53%	5.53%
18 LED DECORATIVE	5.53%	5.53%
20 LED DECORATIVE	5.53%	5.53%
22 LED DECORATIVE	5.53%	5.53%
28 LED DECORATIVE	5.53%	5.53%
30 LED DECORATIVE	5.53%	5.53%
43 LED DECORATIVE	5.53%	5.53%
53 LED DECORATIVE	5.53%	5.53%
80 LED DECORATIVE	5.53%	5.53%
100 LED DECORATIVE	5.53%	5.53%

150 LED DECORATIVE	5.53%	5.53%
170 LED DECORATIVE	5.53%	5.53%
16 LED STANDARD	5.53%	5.53%
17 LED STANDARD	5.53%	5.53%
18 LED STANDARD	5.53%	5.53%
20 LED STANDARD	5.53%	5.53%
28 LED STANDARD	5.53%	5.53%
36 LED STANDARD	5.53%	5.53%
42 LED STANDARD	5.53%	5.53%
43 LED STANDARD	5.53%	5.53%
53 LED STANDARD	5.53%	5.53%
70 LED STANDARD	5.53%	5.53%
80 LED STANDARD	5.53%	5.53%
135 LED STANDARD	5.53%	5.53%
140 LED STANDARD	5.53%	5.53%
165 LED STANDARD	5.53%	5.53%
170 LED STANDARD	5.53%	5.53%

Table A.5.10: Obsolete light types

Light specification	Daily Charge (No contribution) (c/day)	Daily Charge (Full upfront contribution) (c/day)
70 HPS STANDARD	5.53%	N/A
80 HPS STANDARD	5.53%	N/A
125 HPS STANDARD	5.53%	N/A
250 HPS STANDARD	5.53%	N/A
400 HPS STANDARD	5.53%	N/A
40 FLU STANDARD	5.53%	N/A
100 INC STANDARD	5.53%	N/A
70 MH STANDARD	5.53%	N/A
80 MH STANDARD	5.53%	N/A
150 MH STANDARD	5.53%	N/A
250 MH STANDARD	5.53%	N/A

42 MV STANDARD	5.53%	N/A
50 MV STANDARD	5.53%	N/A
70 MV STANDARD	5.53%	N/A
80 MV STANDARD	5.53%	N/A
125 MV STANDARD	5.53%	N/A
150 MV STANDARD	5.53%	N/A
250 MV STANDARD	5.53%	N/A
400 MV STANDARD	5.53%	N/A
17 LED DECORATIVE	5.53%	5.53%
34 LED DECORATIVE	5.53%	5.53%
36 LED DECORATIVE	5.53%	5.53%
42 LED DECORATIVE	5.53%	5.53%
155 LED DECORATIVE	5.53%	5.53%
22 LED STANDARD	5.53%	5.53%
27 LED STANDARD	5.53%	5.53%
68 LED STANDARD	5.53%	5.53%
155 LED STANDARD	5.53%	5.53%
160 LED STANDARD	5.53%	5.53%

Prices for demand-based tariffs on the distribution network (RT5 to RT8 and RT11[10])

Demand charges

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

Table A.5.11: 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	11.19%	8.72%
300 to 1,000	8.72%	8.72%
1,000 to 1,500	8.72%	8.72%

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

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

Table A.5.12: 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	11.19%	8.72%
300 to 1,000	8.72%	8.72%
1,000 to 1,500	8.72%	8.72%

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

Table A.5.13: 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	11.19%	8.72%	8.72%
Forrest Avenue	WFRT	CBD	11.19%	8.72%	8.72%
Hay Street	WHAY	CBD	11.19%	8.72%	8.72%
Milligan Street	WMIL	CBD	11.19%	8.72%	8.72%
Wellington Street	WWNT	CBD	11.19%	8.72%	8.72%
Black Flag	WBKF	Mining	11.19%	8.72%	8.72%
Boulder	WBLD	Mining	11.19%	8.72%	8.72%
Bounty	WBNY	Mining	11.19%	8.72%	8.72%
West Kalgoorlie	WWKT	Mining	11.19%	8.72%	8.72%
Albany	WALB	Mixed	11.19%	8.72%	8.72%
Boddington	WBOD	Mixed	11.19%	8.72%	8.72%
Bunbury Harbour	WBUH	Mixed	11.19%	8.72%	8.72%
Busselton	WBSN	Mixed	11.19%	8.72%	8.72%
Byford	WBYF	Mixed	11.19%	8.72%	8.72%
Capel	WCAP	Mixed	11.19%	8.72%	8.72%
Chapman	WCPN	Mixed	11.19%	8.72%	8.72%
Darlington	WDTN	Mixed	11.19%	8.72%	8.72%

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)
Durlacher Street	WDUR	Mixed	11.19%	8.72%	8.72%
Eneabba	WENB	Mixed	11.19%	8.72%	8.72%
Geraldton	WGTN	Mixed	11.19%	8.72%	8.72%
Marriott Road	WMRR	Mixed	11.19%	8.72%	8.72%
Muchea	WMUC	Mixed	11.19%	8.72%	8.72%
Northam	WNOR	Mixed	11.19%	8.72%	8.72%
Picton	WPIC	Mixed	11.19%	8.72%	8.72%
Rangeway	WRAN	Mixed	11.19%	8.72%	8.72%
Sawyers Valley	WSVY	Mixed	11.19%	8.72%	8.72%
Yanchep	WYCP	Mixed	11.19%	8.72%	8.72%
Yilgarn	WYLN	Mixed	11.19%	8.72%	8.72%
Baandee	WBDE	Rural	11.19%	8.72%	8.72%
Beenup	WBNP	Rural	11.19%	8.72%	8.72%
Bridgetown	WBTN	Rural	11.19%	8.72%	8.72%
Carrabin	WCAR	Rural	11.19%	8.72%	8.72%
Cataby	WKMC	Rural	11.19%	8.72%	8.72%
Collie	WCOE	Rural	11.19%	8.72%	8.72%
Coolup	WCLP	Rural	11.19%	8.72%	8.72%
Cunderdin	WCUN	Rural	11.19%	8.72%	8.72%
Katanning	WKAT	Rural	11.19%	8.72%	8.72%
Kellerberrin	WKEL	Rural	11.19%	8.72%	8.72%
Kojonup	WKOJ	Rural	11.19%	8.72%	8.72%
Kondinin	WKDN	Rural	11.19%	8.72%	8.72%
Manjimup	WMJP	Rural	11.19%	8.72%	8.72%
Margaret River	WMRV	Rural	11.19%	8.72%	8.72%
Merredin	WMER	Rural	11.19%	8.72%	8.72%
Moora	WMOR	Rural	11.19%	8.72%	8.72%
Mount Barker	WMBR	Rural	11.19%	8.72%	8.72%
Narrogin	WNGN	Rural	11.19%	8.72%	8.72%

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)
Pinjarra	WPNJ	Rural	11.19%	8.72%	8.72%
Regans	WRGN	Rural	11.19%	8.72%	8.72%
Three Springs	WTSG	Rural	11.19%	8.72%	8.72%
Wagerup	WWGP	Rural	11.19%	8.73%	8.72%
Wagin	WWAG	Rural	11.19%	8.72%	8.72%
Wundowie	WWUN	Rural	11.19%	8.72%	8.72%
Yerbillon	WYER	Rural	11.19%	8.72%	8.72%
Amherst	WAMT	Urban	11.19%	8.72%	8.72%
Arkana	WARK	Urban	11.19%	8.72%	8.72%
Australian Paper Mills	WAPM	Urban	11.19%	8.72%	8.72%
Balcatta	WBCT	Urban	11.19%	8.72%	8.72%
Beechboro	WBCH	Urban	11.19%	8.72%	8.72%
Belmont	WBEL	Urban	11.19%	8.72%	8.72%
Bentley	WBTY	Urban	11.19%	8.72%	8.72%
Bibra Lake	WBIB	Urban	11.19%	8.72%	8.72%
British Petroleum	WBPM	Urban	11.19%	8.72%	8.72%
Canning Vale	WCVE	Urban	11.19%	8.72%	8.72%
Clarence Street	WCLN	Urban	11.19%	8.72%	8.72%
Clarkson	WCKN	Urban	11.19%	8.72%	8.72%
Cockburn Cement	WCCT	Urban	11.19%	8.72%	8.72%
Collier	WCOL	Urban	11.19%	8.72%	8.72%
Cottesloe	WCTE	Urban	11.19%	8.72%	8.72%
Edmund Street	WEDD	Urban	11.19%	8.72%	8.72%
Forrestfield	WFFD	Urban	11.19%	8.72%	8.72%
Gosnells	WGNL	Urban	11.19%	8.72%	8.72%
Hadfields	WHFS	Urban	11.19%	8.72%	8.72%
Hazelmere	WHZM	Urban	11.19%	8.72%	8.72%
Henley Brook	WHBK	Urban	11.19%	8.72%	8.72%
Herdsman Parade	WHEP	Urban	11.19%	8.72%	8.72%

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)
Joel Terrace	WJTE	Urban	11.19%	8.72%	8.72%
Joondalup	WJDP	Urban	11.19%	8.72%	8.72%
Kalamunda	WKDA	Urban	11.19%	8.72%	8.72%
Kambalda	WKBA	Urban	11.19%	8.72%	8.72%
Kewdale	WKDL	Urban	11.19%	8.72%	8.72%
Landsdale	WLDE	Urban	11.19%	8.72%	8.72%
Maddington	WMDN	Urban	11.19%	8.72%	8.72%
Malaga	WMLG	Urban	11.19%	8.72%	8.72%
Mandurah	WMHA	Urban	11.19%	8.72%	8.72%
Manning Street	WMAG	Urban	11.19%	8.72%	8.72%
Mason Road	WMSR	Urban	11.19%	8.72%	8.72%
Meadow Springs	WMSS	Urban	11.19%	8.72%	8.72%
Medical Centre	WMCR	Urban	11.19%	8.72%	8.72%
Medina	WMED	Urban	11.19%	8.72%	8.72%
Midland Junction	WMJX	Urban	11.19%	8.72%	8.72%
Morley	WMOY	Urban	11.19%	8.72%	8.72%
Mullaloo	WMUL	Urban	11.19%	8.72%	8.72%
Mundaring Weir	WMWR	Urban	11.19%	8.72%	8.72%
Munday	WMDY	Urban	11.19%	8.72%	8.72%
Murdoch	WMUR	Urban	11.19%	8.72%	8.72%
Myaree	WMYR	Urban	11.19%	8.72%	8.72%
Nedlands	WNED	Urban	11.19%	8.72%	8.72%
North Beach	WNBH	Urban	11.19%	8.72%	8.72%
North Fremantle	WNFL	Urban	11.19%	8.72%	8.72%
North Perth	WNPH	Urban	11.19%	8.72%	8.72%
O'Connor	WOCN	Urban	11.19%	8.72%	8.72%
Osborne Park	WOPK	Urban	11.19%	8.72%	8.72%
Padbury	WPBY	Urban	11.19%	8.72%	8.72%
Piccadilly	WPCY	Urban	11.19%	8.72%	8.72%

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)
Riverton	WRTN	Urban	11.19%	8.72%	8.72%
Rivervale	WRVE	Urban	11.19%	8.72%	8.72%
Rockingham	WROH	Urban	11.19%	8.72%	8.72%
Shenton Park (Old)	WSPA	Urban	11.19%	8.72%	8.72%
Shenton Park (New AA5)	WSPK	Urban	11.19%	8.72%	8.72%
Sth Ftle Power Station	WSFT	Urban	11.19%	8.72%	8.72%
Southern River	WSNR	Urban	11.19%	8.72%	8.72%
Southern Cross	WSNX	Mixed	11.19%	8.72%	8.72%
Tate Street	WTTS	Urban	11.19%	8.72%	8.72%
University	WUNI	Urban	11.19%	8.72%	8.72%
Victoria Park	WVPA	Urban	11.19%	8.72%	8.72%
Waikiki	WWAI	Urban	11.19%	8.72%	8.72%
Wangara	WWGA	Urban	11.19%	8.72%	8.72%
Wanneroo	WWNO	Urban	11.19%	8.72%	8.72%
Welshpool	WWEL	Urban	11.19%	8.72%	8.72%
Wembley Downs	WWDN	Urban	11.19%	8.72%	8.72%
Willetton	WWLN	Urban	11.19%	8.72%	8.72%
Yokine	WYKE	Urban	11.19%	8.72%	8.72%

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 A.5.14: 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	-	-
Urban	8.74%	8.69%
Mining	8.62%	8.67%

Mixed	8.77%	8.67%
Rural	8.76%	8.62%

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 A.5.15: 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	-	-
Urban	8.75%	8.72%
Mining	8.63%	8.91%
Mixed	8.70%	8.78%
Rural	8.71%	8.65%

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[11].

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 A.5.16: Metering prices[12]

Reference Tariff	(c/revenue meter/day)
RT1	11.79%
RT2	11.80%
RT3	11.80%
RT4	11.80%
RT5 – RT8	11.80%

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

12 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)
RT11	11.80%
RT13	11.79%
RT14	11.80%
RT15	11.80%
RT16	11.80%
RT17	11.80%
RT18	11.80%
RT19	11.80%
RT20	11.80%
RT21	11.80%
RT22	11.80%
RT34	11.80%
RT35	11.79%
RT36	11.80%
RT37	11.79%
RT38	11.80%
RT39	11.80%
RT40	11.80%
RT41	11.80%
TRT1, TRT2 and TRT3	11.80%

Table A.5.17: Metering reference service prices

Metering Reference Service	(c/revenue meter/day)
M1	11.79%
M2	11.79%
M3	11.80%
M4	11.80%
M5	11.80%
M6	11.80%
M7 - SIM	11.80%
M7 - AMI	11.79%
M8	11.79%
M9	11.79%
M10	11.80%

Metering Reference Service	(c/revenue meter/day)
M11	11.80%
M12	11.80%
M13	11.80%
M14 - SIM	11.80%
M14 - AMI	11.79%
M15	
M17	11.80%
M18	11.80%
M19	11.80%
M20	11.80%

Table A.5.18: Metering reference service prices

Metering Reference Service	Charge per site visit ($)
M16	1.89%

Administration charges

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

Table A.5.19: Administration charges for RT7 and RT8

CMD	Price (c/day)
<7,000 kVA	8.72%
>=7,000 kVA	8.72%

LV prices

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

Table A.5.20: LV prices RT8

Bundled Tariff	Fixed Price (c/day)	Demand (c/kVA/day)
RT8	8.72%	8.72%

Connection price

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

Table A.5.21: Connection Price RT11

	Connection Price (c/kW/day)
Connection price	3.78%

A.5.2 Transmission prices

Use of system prices

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

Table A.5.22: Transmission prices TRT1

Substation	TNI	Use of System Price (c/kW/day)
Albany	WALB	11.18%
Alcoa Pinjarra	WAPJ	11.18%
Amherst	WAMT	11.17%
Arkana	WARK	11.18%
Australian Fused Materials	WAFM	11.19%
Australian Paper Mills	WAPM	11.18%
Baandee (WC)	WBDE	11.18%
Balcatta	WBCT	11.18%
Beckenham	WBEC	11.18%
Beechboro	WBCH	11.19%
Beenup	WBNP	11.18%
Belmont	WBEL	11.18%
Bentley	WBTY	11.19%
Bibra Lake	WBIB	11.18%
Binningup Desalination Plant	WBDP	11.17%
Black Flag	WBKF	11.18%
Boddington	WBOD	11.19%
Boddington Gold Mine	WBGM	11.18%
Boulder	WBLD	11.18%
Bounty	WBNY	11.18%
Bridgetown	WBTN	11.18%
British Petroleum	WBPM	11.18%
Broken Hill Kwinana	WBHK	11.17%

Substation	TNI	Use of System Price (c/kW/day)
Bunbury Harbour	WBUH	11.17%
Busselton	WBSN	11.18%
Byford	WBYF	11.18%
Canning Vale	WCVE	11.18%
Capel	WCAP	11.18%
Carrabin	WCAR	11.18%
Cataby Kerr McGee	WKMC	11.18%
Chapman	WCPN	11.18%
Clarence Street	WCLN	11.18%
Clarkson	WCKN	11.17%
Cockburn Cement	WCCT	11.18%
Cockburn Cement Ltd	WCCL	11.19%
Collie	WCOE	11.18%
Collier	WCOL	11.18%
Cook Street	WCKT	11.17%
Coolup	WCLP	11.18%
Cottesloe	WCTE	11.18%
Cunderdin	WCUN	11.18%
Darlington	WDTN	11.18%
Edgewater	WEDG	11.19%
Edmund Street	WEDD	11.19%
Eneabba	WENB	11.18%
Forrest Ave	WFRT	11.18%
Forrestfield	WFFD	11.18%
Geraldton	WGTN	11.18%
Glen Iris	WGNI	11.18%
Golden Grove	WGGV	11.18%
Gosnells	WGNL	11.17%
Hadfields	WHFS	11.19%
Hay Street	WHAY	11.19%
Hazelmere	WHZM	11.18%
Henley Brook	WHBK	11.17%
Herdsman Parade	WHEP	11.18%

Substation	TNI	Use of System Price (c/kW/day)
Joel Terrace	WJTE	11.18%
Joondalup	WJDP	11.18%
Kalamunda	WKDA	11.18%
Katanning	WKAT	11.18%
Kellerberrin	WKEL	11.18%
Kewdale	WKDL	11.19%
Kojonup	WKOJ	11.19%
Kondinin	WKDN	11.18%
Kwinana Alcoa	WAKW	11.18%
Kwinana Desalination Plant	WKDP	11.17%
Kwinana PWS	WKPS	11.18%
Landsdale	WLDE	11.18%
Maddington	WMDN	11.19%
Malaga	WMLG	11.18%
Mandurah	WMHA	11.18%
Manjimup	WMJP	11.18%
Manning Street	WMAG	11.18%
Margaret River	WMRV	11.18%
Marriott Road	WMRR	11.19%
Marriott Road Barrack Silicon Smelter	WBSI	11.17%
Mason Road	WMSR	11.18%
Mason Road CSBP	WCBP	11.18%
Mason Road Kerr McGee	WKMK	11.16%
Meadow Springs	WMSS	11.18%
Medical Centre	WMCR	11.18%
Medina	WMED	11.18%
Merredin 66kV	WMER	11.18%
Midland Junction	WMJX	11.18%
Milligan Street	WMIL	11.18%
Moora	WMOR	11.18%
Morley	WMOY	11.17%
Mt Barker	WMBR	11.18%
Muchea	WMUC	11.17%

Substation	TNI	Use of System Price (c/kW/day)
Muchea Kerr McGee	WKMM	11.18%
Muja PWS	WMPS	11.16%
Mullaloo	WMUL	11.19%
Mundaring Weir	WMWR	11.18%
Munday	WMDY	11.18%
Murdoch	WMUR	11.18%
Myaree	WMYR	11.17%
Narrogin	WNGN	11.18%
Nedlands	WNED	11.18%
North Beach	WNBH	11.18%
North Fremantle	WNFL	11.17%
North Perth	WNPH	11.19%
Northam	WNOR	11.18%
Nowgerup	WNOW	11.18%
O'Connor	WOCN	11.18%
Osborne Park	WOPK	11.18%
Padbury	WPBY	11.18%
Parkeston	WPRK	11.18%
Parklands	WPLD	11.18%
Piccadilly	WPCY	11.18%
Picton 66kv	WPIC	11.18%
Pinjarra	WPNJ	11.19%
Rangeway	WRAN	11.18%
Regans	WRGN	11.18%
Riverton	WRTN	11.18%
Rivervale	WRVE	11.18%
Rockingham	WROH	11.18%
Sawyers Valley	WSVY	11.18%
Shenton Park	WSPA	11.18%
South Fremantle 22kV	WSFT	11.18%
Southern River	WSNR	11.18%
Summer St	WSUM	11.18%
Sutherland	WSRD	11.19%

Substation	TNI	Use of System Price (c/kW/day)
Tate Street	WTTS	11.18%
Three Springs	WTSG	11.18%
Three Springs Terminal (Karara)	WTST	11.18%
Tomlinson Street	WTLN	11.18%
University	WUNI	11.18%
Victoria Park	WVPA	11.19%
Wagerup	WWGP	11.17%
Wagin	WWAG	11.18%
Waikiki	WWAI	11.19%
Wangara	WWGA	11.18%
Wanneroo	WWNO	11.18%
Wellington Street	WWNT	11.18%
Welshpool	WWEL	11.18%
Wembley Downs	WWDN	11.18%
West Kalgoorlie	WWKT	11.18%
Western Collieries	WWCL	11.17%
Western Mining	WWMG	11.18%
Westralian Sands	WWSD	11.17%
Willetton	WWLN	11.17%
Worsley	WWOR	11.17%
Wundowie	WWUN	11.18%
Yanchep	WYCP	11.18%
Yerbillon	WYER	11.18%
Yilgarn	WYLN	11.18%
Yokine	WYKE	11.17%

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

Table A.5.23: Reference tariffs RT11, TRT2 and TRT3

Substation	TNI	Use of System Price (c/kW/day)
Albany	WALB	11.18%
Alcoa Pinjarra	WAPJ	11.16%
Badgingarra	WBGA	11.18%

Substation	TNI	Use of System Price (c/kW/day)
Bluewaters	WBWP	11.18%
Boulder	WBLD	11.17%
Cockburn PWS	WCKB	11.20%
Collgar	WCGW	11.18%
Collie PWS	WCPS	11.18%
Emu Downs	WEMD	11.18%
Geraldton	WGTN	11.13%
Greenough Solar Farm	TMGS	11.22%
Kemerton PWS	WKEM	11.18%
Kwinana Alcoa	WAKW	11.20%
Kwinana BESS (KBESS)	WKWB	11.20%
Kwinana Donaldson Road	WKND	11.20%
Kwinana PWS	WKPS	11.20%
Kwinana Waste to Energy	WKWW	11.20%
Landwehr (Alinta)	WLWT	11.18%
Mason Road	WMSR	11.20%
Merredin Power Station	TMDP	11.16%
Merredin Solar Farm	WMSF	11.16%
Muja PWS	WMPS	11.18%
Mumbida Wind Farm	TMBW	11.19%
Mungarra GTs	WMGA	11.17%
Newgen Kwinana	WNGK	11.20%
Newgen Neerabup	WGNN	11.16%
Oakley (Alinta)	WOLY	11.17%
Parkeston	WPKS	11.16%
Pinjar GTs	WPJR	11.20%
Tiwest GT	WKMK	11.16%
Wagerup	WWGP	11.20%
Walkaway Windfarm	WWWF	11.18%
Warradarge Wind Farm	WWDW	11.18%
West Kalgoorlie GTs	WWKT	11.20%
Worsley	WWOR	11.18%

Substation	TNI	Use of System Price (c/kW/day)
Yandin Wind Farm	WYDW	11.16%

Common service prices

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

Table A.5.24: Common Service Prices TRT1

	Common Service Price (c/kW/day)
Common service price	11.17%

Control system service prices

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

Table A.5.25: Control system service prices for reference tariffs RT11, TRT2 and TRT3

	Price (c/kW/day)
Control system service price (Generators)	11.31%

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

Table A.5.26: Control system service prices for reference tariff TRT1

	Price (c/kW/day)
Control system service price (Loads)	11.19%