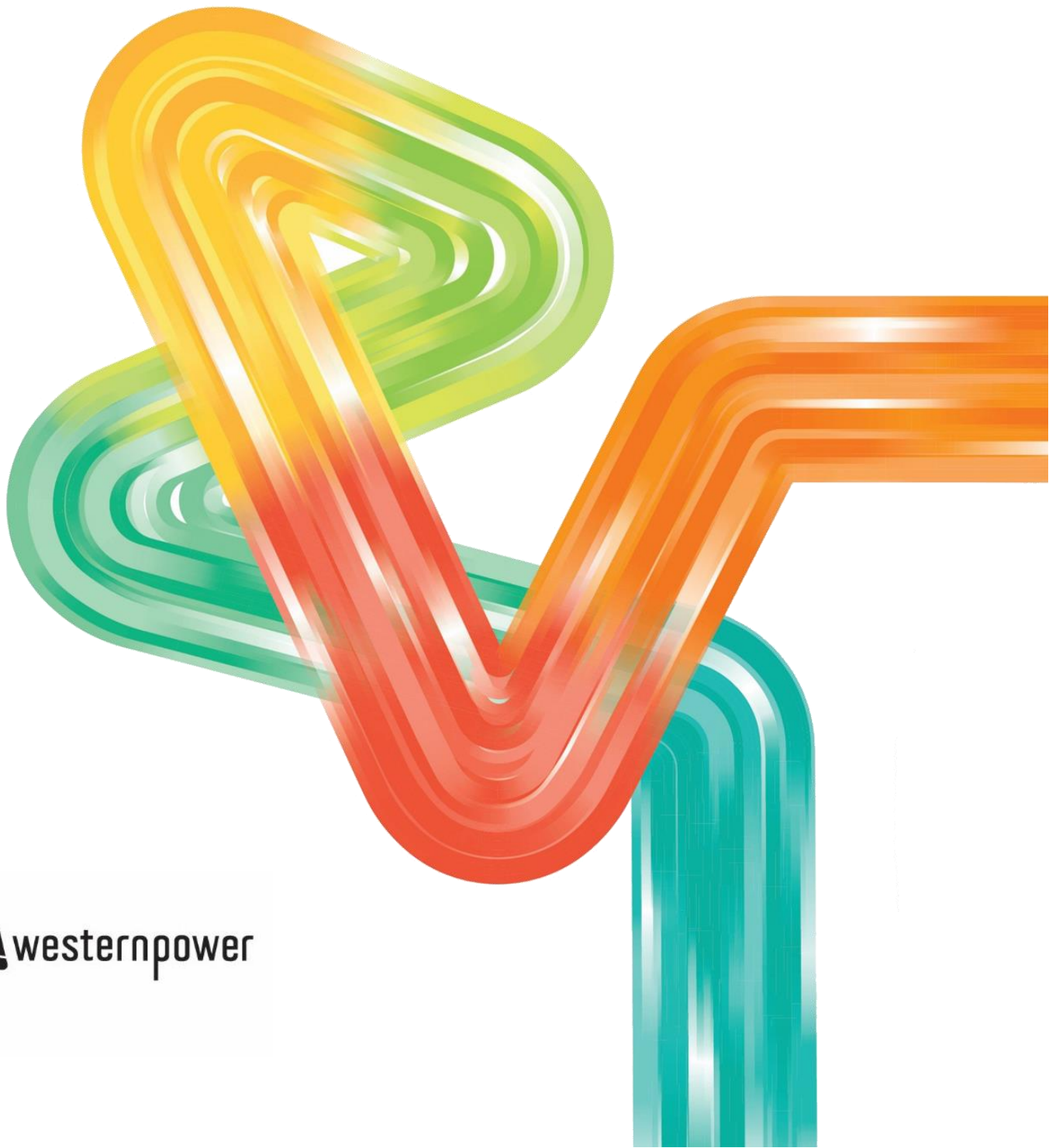


2025-26 Price List for the Western Power Network

Approved by the Economic Regulation Authority 16 May 2025

Public



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1. Introduction

1.1 Overview

This document details Western Power’s price list for the pricing year commencing on 1 July 2025 and ending on 30 June 2026, which represents the fourth 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 arrangement²; 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

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.era.gov.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 2025-26

1.4.1 Revenue targets for 2025-26

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 contract, on a post-tax real basis.

Table 1.1 – Maximum total network revenue target for 2025-26 (\$M nominal)

Maximum total target revenue	2024-25	2025-26
NR_t	1,754	1,862

Maximum total target revenue	2024-25	2025-26
TEC _t	199	236
DTEC _t	+7	+14
TNR _t	1,960	2,111

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 2025-26 (\$M)

Target Revenue	Revenue (Real)	Revenue (Nominal)
Target Revenue (NR ₂₀₂₅₋₂₆)	1,775	2,111

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 2025-26 Inflation Factor

December 2020 – December 2021 – Actual	3.50%
December 2021 – December 2022 – Actual	7.80%
December 2022 – December 2023 – Actual	4.10%
December 2023 – December 2024 – Actual	2.40%
Derived Inflation Factor	1.189

1.5 Proposed pricing strategy for 2025-26 price list

1.5.1 Overview of pricing strategy for the 2025-26 price list

This section sets out and describes how Western Power's pricing strategy for the 2025-26 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 to 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 but are consistent with movements indicated in the 2024-25 reference tariff change forecast.⁴
- 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.⁵ The proposed price list includes an increase of 5.5 per cent to streetlight asset charges. Similar increases are forecast for the 2026-27 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 2025-26 weighted average price changes with forecast weighted average price changes from the 2024-25 price list

Reference tariff	WAPC FY25 Price List - FY26 Pricing Year	WAPC FY26 Price List - FY26 Pricing Year	Variance
RT1 – Anytime Energy (Residential)	5.60%	8.65%	3.05%
RT2 – Anytime Energy (Business)	6.83%	8.96%	2.13%
RT3 – Time of Use Energy (Residential)	4.44%	12.12%	7.68%
RT4 – Time of Use Energy (Business)	20.82%	19.49%	-1.33%
RT5 – High Voltage Metered Demand	0.05%	2.40%	2.35%
RT6 – Low Voltage Metered Demand	0.09%	2.40%	2.31%
RT7 – High Voltage Contract Maximum Demand	0.01%	2.40%	2.39%
RT8 – Low Voltage Contract Maximum Demand	0.02%	2.34%	2.32%
RT9 – Streetlighting	4.67%	5.32%	0.65%
RT10 – Unmetered Supplies	0.90%	1.45%	0.56%
RT11 – Distribution Entry	1.84%	3.61%	1.77%
RT13 – Anytime Energy (Residential) Bi-directional	5.52%	8.63%	3.11%
RT14 – Anytime Energy (Business) Bi-directional	6.37%	8.77%	2.41%
RT15 – Time of Use (Residential) Bi-directional	4.91%	11.96%	7.05%
RT16 – Time of Use (Business) Bi-directional	21.39%	21.31%	-0.08%
RT17 – Time of Use Energy (Residential)	5.08%	11.92%	6.84%

⁴ Reference tariff change forecast can be found at: <https://www.westernpower.com.au/siteassets/documents/network-access-prices/reference-tariff-change-forecast-2024-25.pdf>

⁵ 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 FY25 Price List - FY26 Pricing Year	WAPC FY26 Price List - FY26 Pricing Year	Variance
RT18 – Time of Use Energy (Business)	19.65%	15.84%	-3.81%
RT19 – Time of Use Demand (Residential)	0.80%	13.68%	12.88%
RT20 – Time of Use Demand (Business)	22.07%	20.64%	-1.43%
RT21 – Multi Part Time of Use Energy (Residential)	5.96%	11.61%	5.66%
RT22 – Multi Part Time of Use Energy (Business)	21.30%	20.29%	-1.01%
RT34 – Super Off-peak Time of Use Energy (Business)	6.07%	8.50%	2.43%
RT35 – Super Off-peak Time of Use Energy (Residential)	5.71%	8.68%	2.97%
RT36 – Super Off-peak Time of Use Demand (Business)	4.67%	8.46%	3.79%
RT37 – Super Off-peak Time of Use Demand (Residential)	2.42%	8.24%	5.82%
RT38 – Low Voltage Distribution Storage	3.68%	4.58%	0.91%
RT39 – High Voltage Distribution Storage	3.68%	4.58%	0.91%
RT40 – Low Voltage Electric Vehicle Charging	4.06%	4.24%	0.18%
RT41 – High Voltage Electric Vehicle Charging	4.03%	4.21%	0.18%
Total Bundled Target Revenue from distribution customers	4.95%	7.20%	2.25%
TRT1 - Transmission exit	7.10%	7.17%	0.07%
TRT2 - Transmission entry	7.10%	6.63%	-0.47%
TRT3 - Transmission storage	7.04%	6.59%	-0.45%
Total Bundled Target Revenue from transmission customers	7.10%	6.87%	-0.22%
Total Bundled Target Revenue	5.08%	7.18%	2.10%

There are a number of general factors that have contributed to the difference in the weighted average price change calculated in accordance with the 2025-26 price list compared with the forecast from the 2024-25 price list. The main drivers of the change are an increase in the:

- amount of TEC Western Power must pay to the State Government; and
- DTEC with FY25 volumes higher than approved leading to +14m in target revenue.

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 2025-26 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 2025-26 (\$M nominal)

Reference tariff	MWh	Customer numbers	Forecast bundled revenue recovered	Average price change
RT1 – Anytime Energy (Residential)	1,765,281	412,667	377.46	8.65%
RT2 – Anytime Energy (Business)	159,805	46,604	63.09	8.96%
RT3 – Time of Use Energy (Residential)^	15,537	2,719	3.25	12.12%
RT4 – Time of Use Energy (Business)^	41,255	1,713	8.59	19.49%
RT5 – High Voltage Metered Demand	682,303	317	58.79	2.40%
RT6 – Low Voltage Metered Demand	1,640,713	3,763	160.35	2.40%
RT7 – High Voltage Contract Maximum Demand	3,359,548	420	222.37	2.40%
RT8 – Low Voltage Contract Maximum Demand	298,829	37	10.35	2.34%
RT9 – Streetlighting	141,748	302,467	50.54	5.32%
RT10 – Unmetered Supplies	48,586	20,513	7.42	1.45%
RT11 – Distribution Entry	197	26	5.08	3.61%
RT13 – Anytime Energy (Residential) Bi-directional	1,459,198	322,386	303.15	8.63%
RT14 – Anytime Energy (Business) Bi-directional	21,830	2,849	5.57	8.77%
RT15 – Time of Use (Residential) Bi-directional^	23,804	4,727	5.21	11.96%
RT16 – Time of Use (Business) Bi-directional^	13,320	321	2.47	21.31%
RT17 – Time of Use Energy (Residential)*	115,399	19,095	21.21	11.92%
RT18 – Time of Use Energy (Business)*	12,608	3,359	5.41	15.84%
RT19 – Time of Use Demand (Residential)*	12,538	163	1.15	13.68%
RT20 – Time of Use Demand (Business)*	45,521	686	8.29	20.64%
RT21 – Multi Part Time of Use Energy (Residential)*	149,544	33,761	32.62	11.61%
RT22 – Multi Part Time of Use Energy (Business)*	4,061	220	0.88	20.29%
RT34 – Super Off-peak Time of Use Energy (Business)**	1,827,942	57,716	269.11	8.50%
RT35 – Super Off-peak Time of Use Energy (Residential)**	1,125,558	254,105	225.27	8.68%
RT36 – Super Off-peak Time of Use Demand (Business)**	18,248	275	2.70	8.46%
RT37 – Super Off-peak Time of Use Demand (Residential)**	322,618	72,834	125.01	8.24%
RT38 – Low Voltage Distribution Storage**	1	9	2.16	4.58%
RT39 – High Voltage Distribution Storage**	1	9	2.16	4.58%
RT40 – Low Voltage Electric Vehicle Charging**	468	30	0.30	4.24%

Reference tariff	MWh	Customer numbers	Forecast bundled revenue recovered	Average price change
RT41 – High Voltage Electric Vehicle Charging**	94	6	0.19	4.21%
Total Bundled Target Revenue distribution customers	13,306,554	1,563,797	1,980.12	7.20%
TRT1 - Transmission exit	874	42	60.18	7.17%
TRT2 - Transmission entry	5,816	38	66.55	6.63%
TRT3 - Transmission storage**	350	3	4.51	6.59%
Total Bundled Target Revenue transmission customers	7,040	80	131.23	6.87%
Total Bundled Target Revenue	13,313,594	1,563,877	2,111.35	7.18%

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	NA6	
D6 – Remote Load / Inverter Control Service	RT26	
D8 – Remote De-energise Service	RT28	
D9 – Remote Re-energise Service	RT29	
D10 – Streetlight LED Replacement Service	RT30	
D11 – Site Visit to Support Remote Re-energise Service	RT31	
D12 – Manual De-energise Service	RT32	
D13 – Manual Re-energise Service	RT33	
A19 – Super Off-peak Energy (Business) Exit Service C17 – Super Off-peak Energy (Business) Bi-directional Service	RT34	STOUL
A18 – Super Off-peak Energy (Residential) Exit Service C16 – Super Off-peak Energy (Residential) Exit Service	RT35	STOUS
A21 – Super Off-peak Demand (Business) Exit Service C19 – Super Off-peak Demand (Business) Bi-directional Service	RT36	DSTOUL
A20 – Super Off-peak Demand (Residential) Exit Service C18 – Super Off-peak Demand (Residential) Bi-directional Service	RT37	DSTOUS
C22 – Transmission Storage Service	TRT3	TRST
C23 – Low Voltage Distribution Storage Service	RT38	LVST
C24 – High Voltage Distribution Storage Service	RT39	HVST
A22 – Low Voltage Electric Vehicle Charging Exit Service C20 – Low Voltage Electric Vehicle Charging Bidirectional Service	RT40	LVEV

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

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

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-Discout);

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

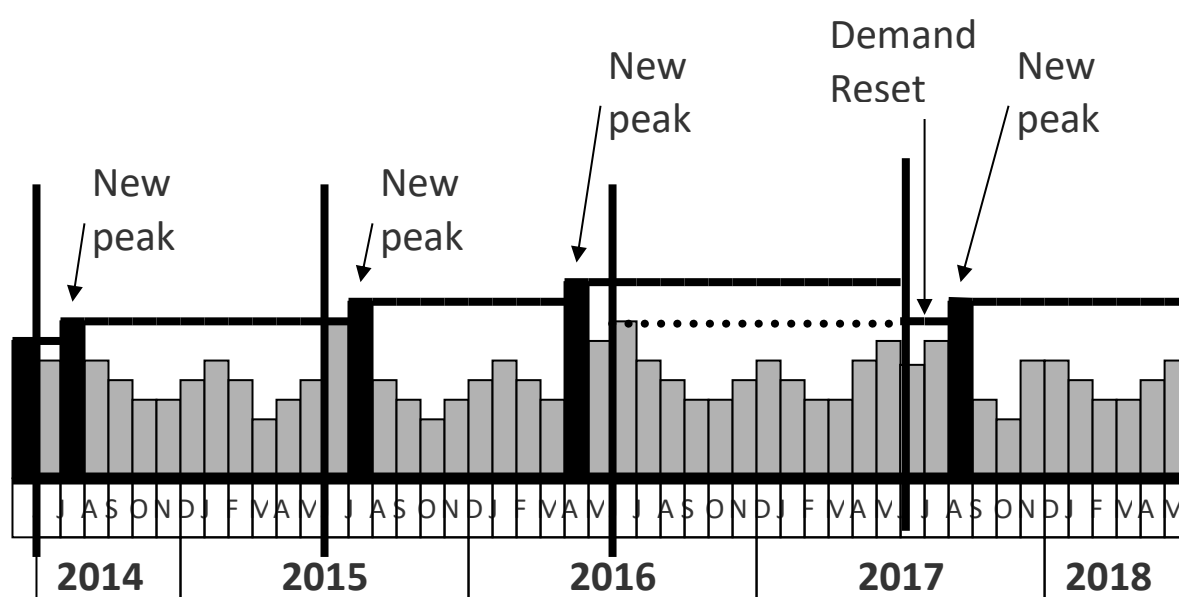
5.3.3 Derivation of rolling 12-month peak

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-Discout);
- 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-Discout);
- 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:

$$\text{ENUC} = \text{ENUC}_{\text{Transmission}} + \text{ENUC}_{\text{Distribution}}$$

Where:

$$\text{ENUC}_{\text{Transmission}} = \text{ENUM} * (\text{PD} - \text{CMD}) * \text{DC}_{\text{Transmission}} / \text{CMD};$$

$$\text{ENUC}_{\text{Distribution}} = \text{ENUM} * (\text{PD} - \text{CMD}) * (\text{DC}_{\text{Distribution}} + \text{DLC}) / \text{CMD};$$

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:

$$\text{ENUC} = \text{ENUC}_{\text{Transmission}} + \text{ENUC}_{\text{Distribution}}$$

Where

$$\text{ENUC}_{\text{Transmission}} = \text{ENUM} * (\text{PD} - \text{CMD}) * \text{DC}_{\text{Transmission}} / \text{CMD};$$

$$\text{ENUC}_{\text{Distribution}} = \text{ENUM} * (\text{PD} - \text{CMD}) * (\text{DC}_{\text{Distribution}} + \text{DLC} + \text{LVC}) / \text{CMD};$$

ENUM is the Excess network usage multiplier factor, which is defined in Table 8.25;

PD	is the peak half-hourly demand during the billing period of the load (expressed in kVA);
CMD	is the nominated CMD for the billing period of the load (expressed in kVA);
DC _{Transmission}	are the applicable transmission components of the fixed and variable demand charges for the billing period for the nominated CMD;
DC _{Distribution}	are the applicable distribution components of the fixed and variable demand charges for the billing period for the nominated CMD;
DLC	are the applicable variable demand length charges for the billing period for the nominated CMD; and
LVC	are the applicable additional fixed and additional demand (low voltage) charges for the billing period for the nominated CMD.

Notes:

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

5.7 Streetlighting (RT9)

RT9 consists of:

- a. a fixed use of system charge (detailed in Table 8.1) which is payable each day;
- b. a variable use of system charge calculated by multiplying the energy price (detailed in Table 8.1) by the estimated quantity of electricity consumed at an exit point (expressed in kWh and is based on the lamp wattage and illumination period); and
- c. a fixed asset charge based on the type of streetlight asset supplied (detailed in Table 8.7 and Table 8.8)

5.8 Unmetered supply (RT10)

RT10 consists of:

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

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

- a. the fixed use of system charge for RT9 (detailed in Table 8.1) which is payable each day; and
- b. the variable use of system charge for RT9 calculated by multiplying the energy price (detailed in Table 8.1) 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:

$$\text{ENUC} = \text{ENUC}_{\text{Transmission}} + \text{ENUC}_{\text{Distribution}}$$

Where

$$\text{ENUC}_{\text{Transmission}} = \text{ENUM} * (\text{PD}_{\text{kW}} - \text{DSOC}_{\text{kW}}) * \text{TEPC} / \text{DSOC}_{\text{kW}};$$

$$\text{ENUC}_{\text{Distribution}} = \text{ENUM} * (\text{PD}_{\text{kVA}} - \text{DSOC}_{\text{kVA}}) * (\text{DLC}) / \text{DSOC}_{\text{kVA}};$$

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

- 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 fixed use of system charge (detailed in Table 8.3) which is payable each day;
- 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);
- 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 8.14 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 5.11: 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 fixed use of system charge (detailed in Table 8.3) which is payable each day;
- 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;
- 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);
- 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);
- 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);
- 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
- 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:

- 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:

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

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:

$$\text{ENUC} = \text{ENUM} * (\text{PD} - \text{DSOC}) * (\text{UOS} + \text{CON} + \text{CSS}) / \text{DSOC}$$

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:

$$\text{ENUC} = \text{ENUM} * (\text{PD} - \text{DSOC}) * (\text{UOS} + \text{CON} + \text{CSS}) / \text{DSOC}$$

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:

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

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	118.608	10.061	-	-	-
Reference tariff 2 – RT2	224.904	13.888	-	-	-
Reference tariff 3 – RT3	118.608	-	22.369	-	5.514
Reference tariff 4 – RT4	411.729	-	26.421	-	6.808
Reference tariff 9 – RT9	8.391	5.671	-	-	-
Reference tariff 10 – RT10	63.799	5.444	-	-	-
Reference tariff 13 – RT13	118.608	10.061	-	-	-
Reference tariff 14 – RT14	224.904	13.888	-	-	-
Reference tariff 15 – RT15	118.608	-	22.369	-	5.514
Reference tariff 16 – RT16	411.729	-	26.421	-	6.808
Reference tariff 17 – RT17	118.608	-	17.131	9.811	7.067
Reference tariff 18 – RT18	234.441	-	29.007	18.476	13.099

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	118.608	7.471	14.809	8.647	5.863
Reference tariff 20 – RT20	282.333	9.551	26.326	15.395	11.162

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	118.608	-	17.068	9.594	7.158	7.158	-
Reference tariff 22 – RT22	224.904	-	29.274	15.764	11.606	11.606	11.606
Reference tariff 34 – RT34	224.904	-	22.727	11.364	8.742	-	5.784
Reference tariff 35 – RT35	118.608	-	17.621	8.811	6.778	-	0.114
Reference tariff 36 – RT36	373.379	7.986	20.625	10.313	7.933	-	5.784
Reference tariff 37 – RT37	118.608	6.608	14.753	7.377	5.675	-	0.114

Table 8.4: Reference tariffs for RT38 and RT39

Bundled tariff	Fixed Price	Energy Rates (network to storage - charging)				
	(c/day)	Off-Peak (c/kWh)	Shoulder (c/kWh)	Super Off-Peak (c/kWh)	On-Peak (c/kWh)	
Reference tariff 38 – RT38	Varies with capacity see Table 8.5 below	0.114	11.001	0.114	22.013	
		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)
		0.114	0.114	11.001	22.013	0.114
Bundled tariff	Fixed Price	Energy Rates (network to storage - charging)				
	(c/day)	Off-Peak (c/kWh)	Shoulder (c/kWh)	Super Off-Peak (c/kWh)	On-Peak (c/kWh)	
Reference tariff 39 – RT39	Varies with capacity see Table 8.5 below	0.114	11.001	0.114	22.013	
		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)
		0.114	0.114	11.001	22.013	0.114

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

Capacity of storage works (kVA)	Fixed Price (c/day)
≥ 0 and < 100	398.558
≥100 and < 1,000	797.114
≥1,000 and < 3,000	1,708.103
≥ 3,000	1,708.103

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	398.558	0.000	7.007	18.219	9.110	4.783
	≥15 & <30	398.558	17.082	3.504	9.110	4.555	3.417
	≥30	398.558	34.162	1.752	4.555	2.278	1.708
Reference tariff 41 – RT41	≥0 & <15	398.558	0.000	7.007	18.219	9.110	4.783
	≥15 & <30	398.558	17.082	3.504	9.110	4.555	3.417
	≥30	398.558	34.162	1.752	4.555	2.278	1.708

8.1.2 Streetlight asset prices

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

Table 8.7: Current light types

Light specification	Daily Charge (No contribution)	Daily Charge (Full upfront contribution)
	(c/day)	(c/day)
42 CFL DECORATIVE	32.248	N/A
42 CFL STANDARD	32.248	N/A
150 HPS STANDARD	36.195	N/A
14 LED DECORATIVE	36.367	12.146
16 LED DECORATIVE	36.367	12.146
18 LED DECORATIVE	36.367	12.146
20 LED DECORATIVE	36.367	12.146
22 LED DECORATIVE	36.367	12.146
28 LED DECORATIVE	36.367	12.146
30 LED DECORATIVE	36.367	12.146
43 LED DECORATIVE	36.367	12.146
53 LED DECORATIVE	36.367	12.146
80 LED DECORATIVE	36.367	12.146
100 LED DECORATIVE	40.849	12.146
150 LED DECORATIVE	40.849	12.146

170 LED DECORATIVE	40.849	12.146
16 LED STANDARD	17.010	12.146
17 LED STANDARD	17.010	12.146
18 LED STANDARD	17.010	12.146
20 LED STANDARD	17.010	12.146
28 LED STANDARD	17.010	12.146
36 LED STANDARD	17.010	12.146
42 LED STANDARD	17.147	12.146
43 LED STANDARD	17.147	12.146
53 LED STANDARD	17.147	12.146
70 LED STANDARD	16.982	12.146
80 LED STANDARD	16.982	12.146
135 LED STANDARD	18.631	12.146
140 LED STANDARD	18.631	12.146
165 LED STANDARD	18.631	12.146
170 LED STANDARD	18.631	12.146

Table 8.8: Obsolete light types

Light specification	Daily Charge (No contribution)	Daily Charge (Full upfront contribution)
	(c/day)	(c/day)
70 HPS STANDARD	27.516	N/A
80 HPS STANDARD	28.318	N/A
125 HPS STANDARD	37.251	N/A
250 HPS STANDARD	36.195	N/A
400 HPS STANDARD	37.251	N/A
40 FLU STANDARD	20.483	N/A
100 INC STANDARD	20.483	N/A
70 MH STANDARD	55.946	N/A
80 MH STANDARD	27.570	N/A
150 MH STANDARD	64.636	N/A
250 MH STANDARD	64.636	N/A
42 MV STANDARD	20.483	N/A
50 MV STANDARD	20.483	N/A
70 MV STANDARD	27.570	N/A

80 MV STANDARD	27.570	N/A
125 MV STANDARD	34.276	N/A
150 MV STANDARD	34.276	N/A
250 MV STANDARD	44.712	N/A
400 MV STANDARD	46.946	N/A
17 LED DECORATIVE	34.635	12.146
34 LED DECORATIVE	34.635	12.146
36 LED DECORATIVE	34.635	12.146
42 LED DECORATIVE	31.664	12.146
155 LED DECORATIVE	40.849	12.146
22 LED STANDARD	17.010	12.146
27 LED STANDARD	17.010	12.146
68 LED STANDARD	16.982	12.146
155 LED STANDARD	18.631	12.146
160 LED STANDARD	18.631	12.146

8.2 Prices for demand-based tariffs on the distribution network (RT5 to RT8 and RT11⁷)

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	211.833	101.434
300 to 1,000	30,430.200	73.686
1,000 to 1,500	82,010.400	35.310

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

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

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	1,222.434	105.675
300 to 1,000	31,702.500	81.416
1,000 to 1,500	88,693.700	42.468

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	61,185.263	35.328	39.022
Forrest Avenue	WFRT	CBD	61,185.263	35.328	39.022
Hay Street	WHAY	CBD	61,185.263	35.328	39.022
Milligan Street	WMIL	CBD	61,185.263	35.328	39.022
Wellington Street	WWNT	CBD	61,185.263	35.328	39.022
Black Flag	WBKF	Mining	61,185.263	52.500	53.741
Boulder	WBLD	Mining	61,185.263	48.942	50.691
Bounty	WBNY	Mining	61,185.263	87.513	83.752
West Kalgoorlie	WWKT	Mining	61,185.263	44.738	46,779
Albany	WALB	Mixed	61,185.263	58.488	58.873
Boddington	WBOD	Mixed	61,185.263	35.678	39.322
Bunbury Harbour	WBUH	Mixed	61,185.263	35.200	38.912
Busselton	WBSN	Mixed	61,185.263	44.781	47.123
Byford	WBYF	Mixed	61,185.263	36.789	40.274
Capel	WCAP	Mixed	61,185.263	41.349	44.183
Chapman	WCPN	Mixed	61,185.263	50.504	52.029
Darlington	WDTN	Mixed	61,185.263	39.465	42.568
Durlacher Street	WDUR	Mixed	61,185.263	46.957	48.989
Eneabba	WENB	Mixed	61,185.263	44.966	47.282

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)
Geraldton	WGTN	Mixed	61,185.263	46.957	48.989
Marriott Road	WMRR	Mixed	61,185.263	34.473	38.288
Muchea	WMUC	Mixed	61,185.263	39.258	42.391
Northam	WNOR	Mixed	61,185.263	48.120	49.987
Picton	WPIC	Mixed	61,185.263	36.901	40.370
Rangeway	WRAN	Mixed	61,185.263	49.132	50.854
Sawyers Valley	WSVY	Mixed	61,185.263	45.237	47.516
Yanchep	WYCP	Mixed	61,185.263	39.170	42.315
Yilgarn	WYLN	Mixed	61,185.263	55.549	56.354
Baandee	WBDE	Rural	61,185.263	52.216	53.497
Beenup	WBNP	Rural	61,185.263	55.746	56.523
Bridgetown	WBTN	Rural	61,185.263	36.069	39.657
Carrabin	WCAR	Rural	61,185.263	56.833	57.455
Cataby	WKMC	Rural	61,185.263	37.122	40.560
Collie	WCOE	Rural	61,185.263	41.676	44.463
Coolup	WCLP	Rural	61,185.263	46.282	48.411
Cunderdin	WCUN	Rural	61,185.263	48.494	50.306
Katanning	WKAT	Rural	61,185.263	44.716	47.069
Kellerberrin	WKEL	Rural	61,185.263	50.986	52.443
Kojonup	WKOJ	Rural	61,185.263	32.654	36.730
Kondinin	WKDN	Rural	61,185.263	34.758	38.533
Manjimup	WMJP	Rural	61,185.263	35.823	39.446
Margaret River	WMRV	Rural	61,185.263	44.857	47.190
Merredin	WMER	Rural	61,185.263	46.739	48.804
Moora	WMOR	Rural	61,185.263	36.145	39.722
Mount Barker	WMBR	Rural	61,185.263	46.619	48.699
Narrogin	WNGN	Rural	61,185.263	51.914	53.239
Pinjarra	WPNJ	Rural	61,185.263	27.257	32.103
Regans	WRGN	Rural	61,185.263	37.122	40.560

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)
Three Springs	WTSG	Rural	61,185.263	36.051	39.642
Wagerup	WWGP	Rural	61,185.263	26.223	31.218
Wagin	WWAG	Rural	61,185.263	45.270	47.543
Wundowie	WWUN	Rural	61,185.263	40.215	43.211
Yerbillon	WYER	Rural	61,185.263	55.508	56.319
Amherst	WAMT	Urban	61,185.263	26.283	31.269
Arkana	WARK	Urban	61,185.263	26.283	31.269
Australian Paper Mills	WAPM	Urban	61,185.263	26.283	31.269
Balcatta	WBCT	Urban	61,185.263	26.283	31.269
Beechboro	WBCH	Urban	61,185.263	26.283	31.269
Belmont	WBEL	Urban	61,185.263	26.283	31.269
Bentley	WBTY	Urban	61,185.263	26.283	31.269
Bibra Lake	WBIB	Urban	61,185.263	26.283	31.269
British Petroleum	WBPM	Urban	61,185.263	26.283	31.269
Canning Vale	WCVE	Urban	61,185.263	26.283	31.269
Clarence Street	WCLN	Urban	61,185.263	26.283	31.269
Clarkson	WCKN	Urban	61,185.263	26.283	31.269
Cockburn Cement	WCCT	Urban	61,185.263	26.283	31.269
Collier	WCOL	Urban	61,185.263	26.283	31.269
Cottesloe	WCTE	Urban	61,185.263	26.283	31.269
Edmund Street	WEDD	Urban	61,185.263	26.283	31.269
Forrestfield	WFFD	Urban	61,185.263	26.283	31.269
Gosnells	WGNL	Urban	61,185.263	26.283	31.269
Hadfields	WHFS	Urban	61,185.263	26.283	31.269
Hazelmere	WHZM	Urban	61,185.263	26.283	31.269
Henley Brook	WHBK	Urban	61,185.263	26.283	31.269
Herdsmen Parade	WHEP	Urban	61,185.263	26.283	31.269
Joel Terrace	WJTE	Urban	61,185.263	26.283	31.269
Joondalup	WJDP	Urban	61,185.263	26.283	31.269

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)
Kalamunda	WKDA	Urban	61,185.263	26.283	31.269
Kambalda	WKBA	Urban	61,185.263	44.781	47.123
Kewdale	WKDL	Urban	61,185.263	26.283	31.269
Landsdale	WLDE	Urban	61,185.263	26.283	31.269
Maddington	WMDN	Urban	61,185.263	26.283	31.269
Malaga	WMLG	Urban	61,185.263	26.283	31.269
Mandurah	WMHA	Urban	61,185.263	26.283	31.269
Manning Street	WMAG	Urban	61,185.263	26.283	31.269
Mason Road	WMSR	Urban	61,185.263	26.283	31.269
Meadow Springs	WMSS	Urban	61,185.263	26.283	31.269
Medical Centre	WMCR	Urban	61,185.263	26.283	31.269
Medina	WMED	Urban	61,185.263	26.283	31.269
Midland Junction	WMJX	Urban	61,185.263	26.283	31.269
Morley	WMOY	Urban	61,185.263	26.283	31.269
Mullaloo	WMUL	Urban	61,185.263	26.283	31.269
Mundaring Weir	WMWR	Urban	61,185.263	26.283	31.269
Munday	WMDY	Urban	61,185.263	26.283	31.269
Murdoch	WMUR	Urban	61,185.263	26.283	31.269
Myaree	WMYR	Urban	61,185.263	26.283	31.269
Nedlands	WNED	Urban	61,185.263	26.283	31.269
North Beach	WNBH	Urban	61,185.263	26.283	31.269
North Fremantle	WNFL	Urban	61,185.263	26.283	31.269
North Perth	WNPH	Urban	61,185.263	26.283	31.269
O'Connor	WOCN	Urban	61,185.263	26.283	31.269
Osborne Park	WOPK	Urban	61,185.263	26.283	31.269
Padbury	WPBY	Urban	61,185.263	26.283	31.269
Piccadilly	WPCY	Urban	61,185.263	42.286	44.986
Riverton	WRTN	Urban	61,185.263	26.283	31.269
Rivervale	WRVE	Urban	61,185.263	26.283	31.269

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)
Rockingham	WROH	Urban	61,185.263	26.283	31.269
Shenton Park (Old)	WSPA	Urban	61,185.263	26.283	31.269
Shenton Park (New AA5)	WSPK	Urban	61,185.263	26.283	31.269
Sth Ftle Power Station	WSFT	Urban	61,185.263	26.283	31.269
Southern River	WSNR	Urban	61,185.263	26.283	31.269
Southern Cross	WSNX	Mixed	61,185.263	55.549	56.354
Tate Street	WTTS	Urban	61,185.263	26.283	31.269
University	WUNI	Urban	61,185.263	26.283	31.269
Victoria Park	WVPA	Urban	61,185.263	26.283	31.269
Waikiki	WWAI	Urban	61,185.263	26.283	31.269
Wangara	WWGA	Urban	61,185.263	26.283	31.269
Wanneroo	WWNO	Urban	61,185.263	26.283	31.269
Welshpool	WWEL	Urban	61,185.263	26.283	31.269
Wembley Downs	WWDN	Urban	61,185.263	26.283	31.269
Willetton	WWLN	Urban	61,185.263	26.283	31.269
Yokine	WYKE	Urban	61,185.263	26.283	31.269

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	2.003	1.415
Mining	0.429	0.300
Mixed	0.935	0.646
Rural	0.582	0.406

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	1.715	1.204
Mining	0.371	0.258
Mixed	0.805	0.558
Rural	0.505	0.347

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.1.2⁸.

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 prices⁹

Reference Tariff	(c/revenue meter/day)
RT1	10.632
RT2	11.221
RT3	11.055
RT4	17.437
RT5 – RT8	19.224
RT11	19.224
RT13	10.632
RT14	11.221

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

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

Reference Tariff	(c/revenue meter/day)
RT15	11.055
RT16	17.437
RT17	19.224
RT18	19.224
RT19	19.224
RT20	19.224
RT21	19.224
RT22	19.224
RT34	11.221
RT35	10.632
RT36	11.221
RT37	10.632
RT38	19.224
RT39	19.224
RT40	19.224
RT41	19.224
TRT1, TRT2 and TRT3	1,090.105

Table 8.15: Metering reference service prices

Metering Reference Service	(c/revenue meter/day)
M1	3.232
M2	3.232
M3	36.891
M4	73.785
M5	19.713
M6	19.713
M7 - SIM	170.895
M7 - AMI	3.232
M8	3.232
M9	3.232
M10	36.891
M11	73.785
M12	19.713
M13	19.713

Metering Reference Service	(c/revenue meter/day)
M14 - SIM	170.895
M14 - AMI	3.232
M15	-
M17	886.956
M18	87.167
M19	886.956
M20	87.167

Table 8.16: Metering reference service prices

Metering Reference Service	Charge per site visit (\$)
M16	24.779

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	6,215.905
>=7,000 kVA	10,825.698

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	1,294.562	12.622

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	1.930

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	21.697
Alcoa Pinjarra	WAPJ	6.154
Amherst	WAMT	5.165
Arkana	WARK	6.592
Australian Fused Materials	WAFM	4.280
Australian Paper Mills	WAPM	6.674
Baandee (WC)	WBDE	23.257
Balcatta	WBCT	6.754
Beckenham	WBEC	17.039
Beechboro	WBCH	5.998
Beenup	WBNP	26.020
Belmont	WBEL	5.315
Bentley	WBTY	6.919
Bibra Lake	WBIB	4.751
Binningup Desalination Plant	WBDP	3.671
Black Flag	WBKF	23.716
Boddington	WBOD	3.879
Boddington Gold Mine	WBGM	3.981
Boulder	WBLD	20.906
Bounty	WBNY	51.360
Bridgetown	WBTN	10.626
British Petroleum	WBPM	9.175
Broken Hill Kwinana	WBHK	7.160
Bunbury Harbour	WBUH	3.510
Busselton	WBSN	10.990
Byford	WBYF	4.749
Canning Vale	WCVE	5.431
Capel	WCAP	8.311

Substation	TNI	Use of System Price (c/kW/day)
Carrabin	WCAR	26.867
Cataby Kerr McGee	WKMC	9.911
Chapman	WCPN	15.461
Clarence Street	WCLN	8.924
Clarkson	WCKN	6.730
Cockburn Cement	WCCT	3.730
Cockburn Cement Ltd	WCCL	3.719
Collie	WCOE	15.013
Collier	WCOL	8.882
Cook Street	WCKT	6.390
Coolup	WCLP	18.615
Cottesloe	WCTE	6.921
Cunderdin	WCUN	20.347
Darlington	WDTN	6.841
Edgewater	WEDG	5.926
Edmund Street	WEDD	6.097
Eneabba	WENB	11.133
Forrest Ave	WFRT	8.936
Forrestfield	WFFD	7.005
Geraldton	WGTN	12.689
Glen Iris	WGNI	4.140
Golden Grove	WGGV	33.260
Gosnells	WGNL	5.639
Hadfields	WHFS	6.776
Hay Street	WHAY	6.776
Hazelmere	WHZM	5.252
Henley Brook	WHBK	5.790
Herdsmen Parade	WHEP	10.276
Joel Terrace	WJTE	9.328
Joondalup	WJDP	6.352
Kalamunda	WKDA	7.157
Katanning	WKAT	17.392
Kellerberrin	WKEL	22.297

Substation	TNI	Use of System Price (c/kW/day)
Kewdale	WKDL	5.211
Kojonup	WKOJ	7.957
Kondinin	WKDN	9.603
Kwinana Alcoa	WAKW	1.646
Kwinana Desalination Plant	WKDP	4.520
Kwinana PWS	WKPS	3.301
Landsdale	WLDE	6.108
Maddington	WMDN	5.488
Malaga	WMLG	5.216
Mandurah	WMHA	4.481
Manjimup	WMJP	10.434
Manning Street	WMAG	7.586
Margaret River	WMRV	17.503
Marriott Road	WMRR	2.940
Marriott Road Barrack Silicon Smelter	WBSI	3.356
Mason Road	WMSR	2.621
Mason Road CSBP	WCBP	3.963
Mason Road Kerr McGee	WKMK	2.401
Meadow Springs	WMSS	5.082
Medical Centre	WMCR	8.039
Medina	WMED	3.784
Merredin 66kV	WMER	18.974
Midland Junction	WMJX	6.385
Milligan Street	WMIL	7.568
Moora	WMOR	10.687
Morley	WMOY	6.962
Mt Barker	WMBR	18.881
Muchea	WMUC	6.677
Muchea Kerr McGee	WKMM	10.083
Muja PWS	WMPS	2.007
Mullaloo	WMUL	6.561
Mundaring Weir	WMWR	10.243
Munday	WMDY	7.072

Substation	TNI	Use of System Price (c/kW/day)
Murdoch	WMUR	4.230
Myaree	WMYR	8.081
Narrogin	WNGN	23.019
Nedlands	WNED	7.567
North Beach	WNBH	6.754
North Fremantle	WNFL	6.793
North Perth	WNPH	5.765
Northam	WNOR	13.598
Nowgerup	WNOW	7.791
O'Connor	WOCN	7.048
Osborne Park	WOPK	7.325
Padbury	WPBY	6.842
Parkeston	WPRK	23.799
Parklands	WPLD	5.223
Piccadilly	WPCY	18.926
Picton 66kv	WPIC	4.837
Pinjarra	WPNJ	3.735
Rangeway	WRAN	14.391
Regans	WRGN	11.450
Riverton	WRTN	4.676
Rivervale	WRVE	7.270
Rockingham	WROH	4.006
Sawyers Valley	WSVY	11.348
Shenton Park	WSPA	7.872
South Fremantle 22kV	WSFT	5.090
Southern River	WSNR	4.909
Summer St	WSUM	9.627
Sutherland	WSRD	5.765
Tate Street	WTTS	8.129
Three Springs	WTSG	10.614
Three Springs Terminal (Karara)	WTST	25.632
Tomlinson Street	WTLN	8.235
University	WUNI	8.728

Substation	TNI	Use of System Price (c/kW/day)
Victoria Park	WVPA	7.948
Wagerup	WWGP	2.927
Wagin	WWAG	17.824
Waikiki	WWAI	4.379
Wangara	WWGA	6.272
Wanneroo	WWNO	6.600
Wellington Street	WWNT	9.579
Welshpool	WWEL	5.180
Wembley Downs	WWDN	7.729
West Kalgoorlie	WWKT	17.301
Western Collieries	WWCL	2.946
Western Mining	WWMG	3.463
Westralian Sands	WWSD	7.535
Willetton	WWLN	4.977
Worsley	WWOR	2.444
Wundowie	WWUN	13.871
Yanchep	WYCP	6.610
Yerbillon	WYER	25.834
Yilgarn	WYLN	19.404
Yokine	WYKE	7.159

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

Table 8.21: Reference tariffs RT11, TRT2 and TRT3

Substation	TNI	Use of System Price (c/kW/day)
Albany	WALB	2.782
Alcoa Pinjarra	WAPJ	2.473
Badgingarra	WBGA	2.836
Bluewaters	WBWP	2.799
Boulder	WBLD	2.014
Cockburn PWS	WCKB	1.697
Collgar	WCGW	3.212
Collie PWS	WCPS	3.255

Substation	TNI	Use of System Price (c/kW/day)
Emu Downs	WEMD	2.836
Geraldton	WGTN	0.476
Greenough Solar Farm	TMGS	0.606
Kemerton PWS	WKEM	2.262
Kwinana Alcoa	WAKW	1.750
Kwinana BESS (KBESS)	WKWB	1.697
Kwinana Donaldson Road	WKND	1.330
Kwinana PWS	WKPS	1.697
Kwinana Waste to Energy	WKWW	1.330
Landwehr (Alinta)	WLWT	2.111
Mason Road	WMSR	1.330
Merredin Power Station	TMDP	2.338
Merredin Solar Farm	WMSF	2.338
Muja PWS	WMPS	3.416
Mumbida Wind Farm	TMBW	2.878
Mungarra GTs	WMGA	2.828
Newgen Kwinana	WNGK	1.974
Newgen Neerabup	WGNN	1.739
Oakley (Alinta)	WOLY	2.354
Parkeston	WPKS	2.428
Pinjar GTs	WPJR	1.411
Tiwest GT	WKMK	1.371
Wagerup	WWGP	1.946
Walkaway Windfarm	WWWF	3.122
Warradarge Wind Farm	WWDW	2.836
West Kalgoorlie GTs	WWKT	1.974
Worsley	WWOR	2.210
Yandin Wind Farm	WYDW	1.739

8.3.2 Common service prices

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

Table 8.22: Common Service Prices TRT1

	Common Service Price (c/kW/day)
Common service price	6.480

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)	0.274

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)	2.431

8.4 Excess network usage charges – substation classification

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

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

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

8.5 Other prices

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

Table 8.26: Supply abolishment charges for RT25

Location	Charge (\$)
Whole current meters metropolitan area ¹⁰	514.464
Whole current meters non-Metropolitan area	655.288

¹⁰ As defined in the Electricity Industry (Metering) Code

Location	Charge (\$)
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	6.312
RT29	6.312

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

Table 8.28: Metering prices for manual services

Metering Reference Service		Metropolitan Charge per site visit (\$)	Country Metropolitan Charge per site visit (\$)	Country Charge per site visit (\$)
RT31	AMS standard	22.007	27.051	38.203
	AMS urgent	88.167	130.554	177.630
RT32	Standard	71.474	71.474	71.474
RT33	Standard	71.474	71.474	71.474
	Urgent	180.334	180.334	180.334

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 $\geq 30\text{kVA}$ to $\leq 200\text{ kVA}$	\$250.00
Enquiry Fee $> 200\text{ kVA}$	\$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)	\$6.312 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 2025-26 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 2025-26 (\$M Nominal)

Reference Service	Reference Tariff	Avoidable Cost	Stand-alone Cost	Forecast Revenue Recovered from Reference Tariff
A1	RT1	62.53	1,053.89	377.46
A2	RT2	13.83	826.95	63.09
A3	RT3	0.50	770.16	3.25
A4	RT4	3.17	781.18	8.59
A5, C5	RT5	6.36	558.23	58.79
A6, C6	RT6	20.58	859.07	160.35
A7, C7	RT7	36.94	694.78	222.37
A8, C8	RT8	1.16	773.07	10.35
A9	RT9	16.75	808.70	50.54
A10	RT10	1.54	773.92	7.42
B1	RT11	0.76	771.39	5.08
C1	RT13	55.42	1,018.50	303.15
C2	RT14	0.93	771.84	5.57
C3	RT15	1.01	772.38	5.21
C4	RT16	1.26	773.19	2.47
A12, C9	RT17	4.46	787.62	21.21
A13, C10	RT18	3.15	781.16	5.41
A14, C11	RT19	0.25	768.92	1.15
A15, C12	RT20	2.27	777.38	8.29
A16, C13	RT21	19.45	850.74	32.62
A17, C14	RT22	0.20	768.74	0.88
A19, C17	RT34	47.18	966.65	269.11

Reference Service	Reference Tariff	Avoidable Cost	Stand-alone Cost	Forecast Revenue Recovered from Reference Tariff
A18, C16	RT35	48.07	983.61	225.27
A21, C19	RT36	0.22	768.84	2.70
A20, C18	RT37	13.78	829.73	125.01
C23	RT38	0.01	767.93	2.16
C24	RT39	0.01	529.92	2.16
A22, C20	RT40	0.04	768.06	0.30
A23, C21	RT41	0.01	529.90	0.19
A11	TRT1	2.39	423.97	60.18
B2	TRT2	2.39	86.33	66.55
C22	TRT3	2.39	76.69	4.51

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:

- 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
- 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 2025-26 (\$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	482.84	396.21	54.81	72.01	0.00	176.98	1,182.85	228.52	1,182.85	56.02%
LV business - small	229.24	189.19	21.25	7.78	0.00	19.12	466.57	75.60	466.57	22.10%
LV business - large	80.77	8.42	7.89	0.26	0.00	0.64	97.99	15.42	97.99	4.64%
HV business	158.25	16.47	13.72	0.06	0.00	0.14	188.64	60.36	188.64	8.93%

Streetlights	0.00	0.44	0.00	0.00	33.23	4.90	38.57	7.54	38.57	1.83%
Unmetered	0.79	1.86	0.09	0.00	0.00	2.76	5.50	1.33	5.50	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	131.23	131.23	6.22%
Total	951.89	612.59	97.76	80.10	33.23	204.53	1,980.11	520.01	2,111.35	100.00%

Distribution revenue of \$1,980 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:

- reflect the service provider's total efficient costs of serving the customers that are currently on that reference tariff;
- 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
- 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 2025-26 (\$M nominal)

Reference tariff	MWh	Customer numbers	Forecast bundled revenue recovered
RT1 – Anytime Energy (Residential)	1,765,281	412,667	377.46
RT2 – Anytime Energy (Business)	159,805	46,604	63.09
RT3 – Time of Use Energy (Residential)	15,537	2,719	3.25
RT4 – Time of Use Energy (Business)	41,255	1,713	8.59
RT5 – High Voltage Metered Demand	682,303	317	58.79
RT6 – Low Voltage Metered Demand	1,640,713	3,763	160.35
RT7 – High Voltage Contract Maximum Demand	3,359,548	420	222.37

Reference tariff	MWh	Customer numbers	Forecast bundled revenue recovered
RT8 – Low Voltage Contract Maximum Demand	298,829	37	10.35
RT9 – Streetlighting	141,748	302,467	50.54
RT10 – Unmetered Supplies	48,586	20,513	7.42
RT11 – Distribution Entry	197	26	5.08
RT13 – Anytime Energy (Residential) Bi-directional	1,459,198	322,386	303.15
RT14 – Anytime Energy (Business) Bi-directional	21,830	2,849	5.57
RT15 – Time of Use (Residential) Bi-directional	23,804	4,727	5.21
RT16 – Time of Use (Business) Bi-directional	13,320	321	2.47
RT17 – Time of Use Energy (Residential)	115,399	19,095	21.21
RT18 – Time of Use Energy (Business)	12,608	3,359	5.41
RT19 – Time of Use Demand (Residential)	12,538	163	1.15
RT20 – Time of Use Demand (Business)	45,521	686	8.29
RT21 – Multi Part Time of Use Energy (Residential)	149,544	33,761	32.62
RT22 – Multi Part Time of Use Energy (Business)	4,061	220	0.88
RT34 – Super Off-peak Time of Use Energy (Business)	1,827,942	57,716	269.11
RT35 – Super Off-peak Time of Use Energy (Residential)	1,125,558	254,105	225.27
RT36 – Super Off-peak Time of Use Demand (Business)	18,248	275	2.70
RT37 – Super Off-peak Time of Use Demand (Residential)	322,618	72,834	125.01
RT38 – Low Voltage Distribution Storage	0	9	2.16
RT39 – High Voltage Distribution Storage	0	9	2.16
RT40 – Low Voltage Electric Vehicle Charging	468	30	0.30
RT41 – High Voltage Electric Vehicle Charging	94	6	0.19
Total Bundled Target Revenue from distribution customers	13,306,554	1,563,797	1,980.12
TRT1 - Transmission exit	874	42	60.18
TRT2 - Transmission entry	5,816	35	66.55
TRT3 - Transmission storage	350	3	4.51
Total Bundled Target Revenue from transmission customers	7,040	80	131.23
Total Bundled Target Revenue	13,313,594	1,563,877	2,111.35

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 2025-26 tariffs exceeds the avoidable cost calculated for the comparison of stand-alone and avoidable costs above, except for reference tariffs RT8, RT9, RT18 and RT21 which have minor variances between avoidable and the variable tariff components. The difference for RT9 can be explained due to the inclusion of the fixed asset charge in the avoidable cost stack for streetlights, this has led to the variable tariff component being lower than the avoidable cost.

Table A.4 Demonstration that variable costs exceed avoidable costs of reference tariff provision for 2025-26 (\$M nominal)

Reference Service	Reference Tariff	Avoidable Cost	Variable tariff components
A1	RT1	62.53	182.80
A2	RT2	13.83	22.92
A3	RT3	0.50	1.96
A4	RT4	3.17	5.90
A5, C5	RT5	6.36	22.23
A6, C6	RT6	20.58	104.24
A7, C7	RT7	36.94	124.96
A8, C8	RT8	1.16	1.07
A9	RT9	16.75	8.04
A10	RT10	1.54	2.65
B1	RT11	0.76	5.07
C1	RT13	55.42	151.07
C2	RT14	0.93	3.11
C3	RT15	1.01	2.97
C4	RT16	1.26	1.97
A12, C9	RT17	4.46	11.61
A13, C10	RT18	3.15	2.30
A14, C11	RT19	0.25	1.06
A15, C12	RT20	2.27	7.53
A16, C13	RT21	19.45	15.63
A17, C14	RT22	0.20	0.68
A19, C17	RT34	47.18	219.37

Reference Service	Reference Tariff	Avoidable Cost	Variable tariff components
A18, C16	RT35	48.07	105.40
A21, C19	RT36	0.22	2.31
A20, C18	RT37	13.78	90.66
C23	RT38	0.01	2.13
C24	RT39	0.01	2.13
A22, C20	RT40	0.04	0.25
A23, C21	RT41	0.01	0.18

Notes: * As customers continue to churn off the grandfathered tariffs, some of them may have avoidable cost greater than the variable tariff component due to low customer numbers.

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 2025-26.

A.2.1 Transmission pricing cost pools

The following sets out the allocation of revenue to the transmission cost pools for the 2025-26 pricing year.

Table A.5 - Transmission Pricing Cost Pools for 2025-26 (\$M Nominal)

Cost Pool	Allocated Revenue
Entry connection	13.09
Exit connection HV	3.17
Exit connection LV	135.68
CSS entry	5.92
CSS exit	42.62
UOS entry	48.23
UOS exit	133.72
Common service	137.30
Metering CT/VT	0.27
Total	520.01

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 2025-26 (\$M Nominal)

Cost Pool	Locational Zone					Total
	CBD	Urban	Mining	Mixed	Rural	
High Voltage Network	6.45	225.01	11.54	283.37	425.52	951.89
Low Voltage Network	7.62	394.88	0.30	143.49	66.29	612.59
Transformers	2.86	45.77	0.33	27.20	21.61	97.76
Streetlight Assets	0.82	32.08	0.59	21.88	24.74	80.10
Metering	0.34	13.31	0.24	9.08	10.26	33.23
Administration	2.08	81.91	1.50	55.87	63.17	204.53
Revenue requirement	20.17	792.96	14.50	540.89	611.60	1,980.11

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

2025-26 cost of service	Streetlights	Metering
Opening RAB	85.44	318.49
Return on asset	6.44	13.66
Depreciation	9.50	29.09

2025-26 cost of service	Streetlights	Metering
Opex	16.49	20.55
Indirect cost allocation	-	4.03
Cost of service	32.44	67.34

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 FY26 price list, the smoothed target revenue used was \$33.2 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	Baseline \$/year FY25	Annual change FY25 to FY26	Baseline \$/year FY26
Low consumption end-user	0%	5%	11%	616	9%	672

Representative end-user	Annual change FY22 to FY23	Annual change FY23 to FY24	Annual change FY24 to FY25	Baseline \$/year FY25	Annual change FY25 to FY26	Baseline \$/year FY26
Medium consumption end-user	0%	4%	10%	751	9%	817
High consumption end-user	0%	3%	9%	903	9%	981
Typical solar end-user	0%	3%	10%	814	9%	885
Typical non-solar end-user	0%	4%	10%	741	9%	806

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	Baseline \$/year FY25	Annual change FY25 to FY26	Baseline \$/year FY26
Low consumption end-user	0%	12%	12%	669	11%	743
Medium consumption end-user	0%	14%	11%	840	12%	938
High consumption end-user	0%	14%	11%	1,030	12%	1,154
Typical solar end-user	0%	14%	11%	886	12%	989
Typical non-solar end-user	0%	13%	11%	827	12%	923

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	Baseline \$/year FY25	Annual change FY25 to FY26	Baseline \$/year FY26
Low consumption end-user	0%	9%	12%	629	11%	697
Medium consumption end-user	0%	11%	11%	750	11%	834
High consumption end-user	0%	12%	10%	885	12%	989
Typical solar end-user	0%	12%	11%	815	11%	909
Typical non-solar end-user	0%	11%	11%	741	11%	824

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	Baseline \$/year FY25	Annual change FY25 to FY26	Baseline \$/year FY26
Low consumption end-user	0%	13%	22%	698	11%	773
Medium consumption end-user	0%	14%	19%	813	11%	905
High consumption end-user	0%	15%	17%	938	12%	1,047
Typical solar end-user	0%	14%	19%	870	11%	969
Typical non-solar end-user	0%	14%	19%	803	11%	893

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	Baseline \$/year FY25	Annual change FY25 to FY26	Baseline \$/year FY26
Low consumption end-user	0%	12%	12%	652	11%	723
Medium consumption end-user	0%	14%	12%	793	11%	884
High consumption end-user	0%	15%	11%	952	12%	1,065
Typical solar end-user	0%	14%	12%	867	12%	967
Typical non-solar end-user	0%	14%	12%	783	11%	872

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	Baseline \$/year FY25	Annual change FY25 to FY26	Baseline \$/year FY26
Low consumption end-user		0%	11%	598	9%	651
Medium consumption end-user		0%	10%	717	9%	780
High consumption end-user		0%	9%	852	9%	926
Typical solar end-user		0%	10%	826	9%	898
Typical non-solar end-user		0%	10%	708	9%	770

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	Baseline \$/year FY25	Annual change FY25 to FY26	Baseline \$/year FY26
Low consumption end-user		0%	14%	600	9%	654
Medium consumption end-user		0%	15%	712	9%	775
High consumption end-user		0%	15%	834	9%	906
Typical solar end-user		0%	15%	805	9%	875
Typical non-solar end-user		0%	15%	702	9%	764

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	Baseline \$/year FY25	Annual change FY25 to FY26	Baseline \$/year FY26
Low consumption end-user	0%	6%	12%	1,032	9%	1,126
Medium consumption end-user	0%	5%	11%	1,462	9%	1,592
High consumption end-user	0%	3%	9%	2,202	9%	2,393
Typical solar end-user	0%	3%	9%	2,129	9%	2,314
Typical non-solar end-user	0%	3%	9%	2,511	9%	2,728

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	Baseline \$/year FY25	Annual change FY25 to FY26	Baseline \$/year FY26
Low consumption end-user	0%	7%	12%	1,729	12%	1,930
Medium consumption end-user	0%	9%	11%	2,215	15%	2,538
High consumption end-user	0%	11%	10%	3,106	18%	3,652
Typical solar end-user	0%	11%	11%	2,722	17%	3,171
Typical non-solar end-user	0%	12%	10%	3,364	18%	3,974

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	Baseline \$/year FY25	Annual change FY25 to FY26	Baseline \$/year FY26
Low consumption end-user	0%	9%	19%	1,127	13%	1,276
Medium consumption end-user	0%	11%	16%	1,587	17%	1,861
High consumption end-user	0%	13%	14%	2,399	21%	2,891
Typical solar end-user	0%	13%	15%	2,302	20%	2,768
Typical non-solar end-user	0%	14%	14%	2,695	21%	3,267

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	Baseline \$/year FY25	Annual change FY25 to FY26	Baseline \$/year FY26
Low consumption end-user	0%	15%	10%	1,335	12%	1,492
Medium consumption end-user	0%	16%	10%	1,781	14%	2,036
High consumption end-user	0%	16%	10%	2,560	17%	2,987
Typical solar end-user	0%	16%	11%	2,447	16%	2,849
Typical non-solar end-user	0%	16%	10%	2,828	17%	3,314

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	Baseline \$/year FY25	Annual change FY25 to FY26	Baseline \$/year FY26
Low consumption end-user	0%	8%	12%	1,089	13%	1,227
Medium consumption end-user	0%	10%	11%	1,551	16%	1,800
High consumption end-user	0%	12%	10%	2,372	19%	2,818
Typical solar end-user	0%	12%	11%	2,242	19%	2,657
Typical non-solar end-user	0%	12%	10%	2,659	19%	3,174

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	Baseline \$/year FY25	Annual change FY25 to FY26	Baseline \$/year FY26
Low consumption end-user		0%	15%	1,010	9%	1,102
Medium consumption end-user		0%	13%	1,369	9%	1,491
High consumption end-user		0%	11%	1,984	9%	2,157
Typical solar end-user		0%	11%	2,069	9%	2,250
Typical non-solar end-user		0%	11%	2,245	9%	2,440

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	Baseline \$/year FY25	Annual change FY25 to FY26	Baseline \$/year FY26
Low consumption end-user		0%	7%	1,547	9%	1,690
Medium consumption end-user		0%	8%	1,906	9%	2,078
High consumption end-user		0%	8%	2,515	9%	2,738
Typical solar end-user		0%	8%	2,553	9%	2,779
Typical non-solar end-user		0%	8%	2,756	9%	2,999

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 2025-26 (\$M Nominal)

Reference Tariff	MWh	Number Customers	Forecast TEC Recovered
RT1 - Anytime Energy (Residential)	1,765,281	412,667	40.28
RT2 - Anytime Energy (Business)	159,805	46,604	3.73
RT3 - Time of Use Energy (Residential)	15,537	2,719	0.30
RT4 - Time of Use Energy (Business)	41,255	1,713	0.78

Reference Tariff	MWh	Number Customers	Forecast TEC Recovered
RT5 - High Voltage Metered Demand	682,303	317	18.53
RT6 - Low Voltage Metered Demand	1,640,713	3,763	42.89
RT7 - High Voltage Contract Maximum Demand	3,359,548	420	11.33
RT8 - Low Voltage Contract Maximum Demand	298,829	37	1.04
RT9 – Streetlighting	141,748	302,467	1.27
RT10 - Unmetered Supplies	48,586	20,513	0.46
RT11 - Distribution Entry	197	26	Not Applicable
RT13 – Anytime Energy (Residential) Bi-directional	1,459,198	322,386	33.30
RT14 – Anytime Energy (Business) Bi-directional	21,830	2,849	0.51
RT15 – Time of Use (Residential) Bi-directional	23,804	4,727	0.45
RT16 – Time of Use (Business) Bi-directional	13,320	321	0.26
RT17 - Time of Use Energy (Residential)	115,399	19,095	2.53
RT18 - Time of Use Energy (Business)	12,608	3,359	0.28
RT19 – Time of Use Demand (Residential)	12,538	163	0.27
RT20 – Time of Use Demand (Business)	45,521	686	0.99
RT21 – Multi Part Time of Use Energy (Residential)	149,544	33,761	3.32
RT22 – Multi Part Time of Use Energy (Business)	4,061	220	0.09
RT34 – Super Off-peak Time of Use Energy (Business)	1,827,942	57,716	40.32
RT35 – Super Off-peak Time of Use Energy (Residential)	1,125,558	254,105	25.39
RT36 – Super Off-peak Time of Use Demand (Business)	18,248	275	0.40
RT37 – Super Off-peak Time of Use Demand (Residential)	322,618	72,834	7.26
RT40 – Low Voltage Electric Vehicle Charging	468	30	0.01
RT41 – High Voltage Electric Vehicle Charging	94	6	0.01
Total			236.00

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	9.15%	7.79%			
Reference tariff 2 - RT2	9.15%	8.30%			
Reference tariff 3 - RT3	9.15%		14.05%		14.04%
Reference tariff 4 - RT4	9.15%		25.00%		25.01%
Reference tariff 9 – RT9	5.53%	4.21%			
Reference tariff 10 – RT10	-	4.19%			
Reference tariff 13 - RT13	9.15%	7.79%			
Reference tariff 14 - RT14	9.15%	8.30%			
Reference tariff 15 - RT15	9.15%		14.05%		14.04%
Reference tariff 16 - RT16	9.15%		25.00%		25.01%
Reference tariff 17 - RT17	9.15%		14.05%	14.05%	14.06%
Reference tariff 18 - RT18	9.15%		27.00%	27.00%	27.00%

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	9.15%	14.04%	14.05%	14.05%	14.04%
Reference tariff 20 - RT20	9.15%	22.00%	22.00%	22.00%	22.00%

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	9.15%		14.05%	14.05%	14.05%	14.05%	
Reference tariff 22 – RT22	9.15%		24.00%	24.00%	24.00%	24.00%	24.00%
Reference tariff 34 – RT34	9.15%		8.30%	8.30%	8.30%		8.29%
Reference tariff 35 – RT35	9.15%		7.79%	7.79%	7.79%		7.55%
Reference tariff 36 – RT36	9.15%	8.30%	8.30%	8.31%	8.30%		8.29%
Reference tariff 37 – RT37	9.15%	7.78%	7.79%	7.79%	7.79%		7.55%

Table A.5.6: Reference tariffs for RT38 and RT39

Bundled tariff	Fixed Price	Energy Rates (network to storage - charging)				
	(c/day)	Off-Peak (c/kWh)	Shoulder (c/kWh)	Super Off-Peak (c/kWh)	On-Peak (c/kWh)	
Reference tariff 38 – RT38	Varies with capacity see Table 8.5 below	4.59%	4.20%	4.59%	4.20%	
		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)
		4.59%	4.59%	4.20%	4.20%	4.59%
Bundled tariff	Fixed Price	Energy Rates (network to storage - charging)				
	(c/day)	Off-Peak (c/kWh)	Shoulder (c/kWh)	Super Off-Peak (c/kWh)	On-Peak (c/kWh)	
Reference tariff 39 – RT39	Varies with capacity see Table 8.5 below	4.59%	4.20%	4.59%	4.20%	
		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)
		4.59%	4.59%	4.20%	4.20%	4.59%

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	4.20%
≥100 and < 1,000	4.20%
≥1,000 and < 3,000	4.20%
≥ 3,000	4.20%

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	4.20%		4.19%	4.20%	4.20%	4.20%
	≥15 & <30	4.20%	4.20%	4.19%	4.20%	4.21%	4.21%
	≥30	4.20%	4.20%	4.22%	4.21%	4.21%	4.21%
Reference tariff 41 – RT41	≥0 & <15	4.20%		4.19%	4.20%	4.20%	4.20%
	≥15 & <30	4.20%	4.20%	4.19%	4.20%	4.21%	4.21%
	≥30	4.20%	4.20%	4.22%	4.21%	4.21%	4.21%

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)	Daily Charge (Full upfront contribution)
	(c/day)	(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 RT11¹¹)

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	2.40%	2.40%
300 to 1,000	2.40%	2.40%
1,000 to 1,500	2.40%	2.40%

¹¹ 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	2.40%	2.40%
300 to 1,000	2.40%	2.40%
1,000 to 1,500	2.40%	2.40%

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	2.40%	2.40%	2.40%
Forrest Avenue	WFRT	CBD	2.40%	2.40%	2.40%
Hay Street	WHAY	CBD	2.40%	2.40%	2.40%
Milligan Street	WMIL	CBD	2.40%	2.40%	2.40%
Wellington Street	WWNT	CBD	2.40%	2.40%	2.40%
Black Flag	WBKF	Mining	2.40%	2.40%	2.40%
Boulder	WBLD	Mining	2.40%	2.40%	2.40%
Bounty	WBNY	Mining	2.40%	2.40%	2.40%
West Kalgoorlie	WWKT	Mining	2.40%	2.40%	2.40%
Albany	WALB	Mixed	2.40%	2.40%	2.40%
Boddington	WBOD	Mixed	2.40%	2.40%	2.40%
Bunbury Harbour	WBUH	Mixed	2.40%	2.40%	2.40%
Busselton	WBSN	Mixed	2.40%	2.40%	2.40%
Byford	WBYF	Mixed	2.40%	2.40%	2.40%
Capel	WCAP	Mixed	2.40%	2.40%	2.40%
Chapman	WCPN	Mixed	2.40%	2.40%	2.40%
Darlington	WDTN	Mixed	2.40%	2.40%	2.40%

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	2.40%	2.40%	2.40%
Eneabba	WENB	Mixed	2.40%	2.40%	2.40%
Geraldton	WGTN	Mixed	2.40%	2.40%	2.40%
Marriott Road	WMRR	Mixed	2.40%	2.40%	2.40%
Muchea	WMUC	Mixed	2.40%	2.40%	2.40%
Northam	WNOR	Mixed	2.40%	2.40%	2.40%
Picton	WPIC	Mixed	2.40%	2.40%	2.40%
Rangeway	WRAN	Mixed	2.40%	2.40%	2.40%
Sawyers Valley	WSVY	Mixed	2.40%	2.40%	2.40%
Yanchep	WYCP	Mixed	2.40%	2.40%	2.40%
Yilgarn	WYLN	Mixed	2.40%	2.40%	2.40%
Baandee	WBDE	Rural	2.40%	2.40%	2.40%
Beenup	WBNP	Rural	2.40%	2.40%	2.40%
Bridgetown	WBTN	Rural	2.40%	2.40%	2.40%
Carrabin	WCAR	Rural	2.40%	2.40%	2.40%
Cataby	WKMC	Rural	2.40%	2.40%	2.40%
Collie	WCOE	Rural	2.40%	2.40%	2.40%
Coolup	WCLP	Rural	2.40%	2.40%	2.40%
Cunderdin	WCUN	Rural	2.40%	2.40%	2.40%
Katanning	WKAT	Rural	2.40%	2.40%	2.40%
Kellerberrin	WKEL	Rural	2.40%	2.40%	2.40%
Kojonup	WKOJ	Rural	2.40%	2.40%	2.40%
Kondinin	WKDN	Rural	2.40%	2.40%	2.40%
Manjimup	WMJP	Rural	2.40%	2.40%	2.40%
Margaret River	WMRV	Rural	2.40%	2.40%	2.40%
Merredin	WMER	Rural	2.40%	2.40%	2.40%
Moora	WMOR	Rural	2.40%	2.40%	2.40%
Mount Barker	WMBR	Rural	2.40%	2.40%	2.40%
Narrogin	WNGN	Rural	2.40%	2.40%	2.40%

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	2.40%	2.40%	2.40%
Regans	WRGN	Rural	2.40%	2.40%	2.40%
Three Springs	WTSG	Rural	2.40%	2.40%	2.40%
Wagerup	WWGP	Rural	2.40%	2.40%	2.40%
Wagin	WWAG	Rural	2.40%	2.40%	2.40%
Wundowie	WWUN	Rural	2.40%	2.40%	2.40%
Yerbillon	WYER	Rural	2.40%	2.40%	2.40%
Amherst	WAMT	Urban	2.40%	2.40%	2.40%
Arkana	WARK	Urban	2.40%	2.40%	2.40%
Australian Paper Mills	WAPM	Urban	2.40%	2.40%	2.40%
Balcatta	WBCT	Urban	2.40%	2.40%	2.40%
Beechboro	WBCH	Urban	2.40%	2.40%	2.40%
Belmont	WBEL	Urban	2.40%	2.40%	2.40%
Bentley	WBTY	Urban	2.40%	2.40%	2.40%
Bibra Lake	WBIB	Urban	2.40%	2.40%	2.40%
British Petroleum	WBPM	Urban	2.40%	2.40%	2.40%
Canning Vale	WCVE	Urban	2.40%	2.40%	2.40%
Clarence Street	WCLN	Urban	2.40%	2.40%	2.40%
Clarkson	WCKN	Urban	2.40%	2.40%	2.40%
Cockburn Cement	WCCT	Urban	2.40%	2.40%	2.40%
Collier	WCOL	Urban	2.40%	2.40%	2.40%
Cottesloe	WCTE	Urban	2.40%	2.40%	2.40%
Edmund Street	WEDD	Urban	2.40%	2.40%	2.40%
Forrestfield	WFFD	Urban	2.40%	2.40%	2.40%
Gosnells	WGNL	Urban	2.40%	2.40%	2.40%
Hadfields	WHFS	Urban	2.40%	2.40%	2.40%
Hazelmere	WHZM	Urban	2.40%	2.40%	2.40%
Henley Brook	WHBK	Urban	2.40%	2.40%	2.40%
Herdsman Parade	WHEP	Urban	2.40%	2.40%	2.40%

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	2.40%	2.40%	2.40%
Joondalup	WJDP	Urban	2.40%	2.40%	2.40%
Kalamunda	WKDA	Urban	2.40%	2.40%	2.40%
Kambalda	WKBA	Urban	2.40%	2.40%	2.40%
Kewdale	WKDL	Urban	2.40%	2.40%	2.40%
Landsdale	WLDE	Urban	2.40%	2.40%	2.40%
Maddington	WMDN	Urban	2.40%	2.40%	2.40%
Malaga	WMLG	Urban	2.40%	2.40%	2.40%
Mandurah	WMHA	Urban	2.40%	2.40%	2.40%
Manning Street	WMAG	Urban	2.40%	2.40%	2.40%
Mason Road	WMSR	Urban	2.40%	2.40%	2.40%
Meadow Springs	WMSS	Urban	2.40%	2.40%	2.40%
Medical Centre	WMCR	Urban	2.40%	2.40%	2.40%
Medina	WMED	Urban	2.40%	2.40%	2.40%
Midland Junction	WMJX	Urban	2.40%	2.40%	2.40%
Morley	WMOY	Urban	2.40%	2.40%	2.40%
Mullaloo	WMUL	Urban	2.40%	2.40%	2.40%
Mundaring Weir	WMWR	Urban	2.40%	2.40%	2.40%
Munday	WMDY	Urban	2.40%	2.40%	2.40%
Murdoch	WMUR	Urban	2.40%	2.40%	2.40%
Myaree	WMYR	Urban	2.40%	2.40%	2.40%
Nedlands	WNED	Urban	2.40%	2.40%	2.40%
North Beach	WNBH	Urban	2.40%	2.40%	2.40%
North Fremantle	WNFL	Urban	2.40%	2.40%	2.40%
North Perth	WNPH	Urban	2.40%	2.40%	2.40%
O'Connor	WOCN	Urban	2.40%	2.40%	2.40%
Osborne Park	WOPK	Urban	2.40%	2.40%	2.40%
Padbury	WPBY	Urban	2.40%	2.40%	2.40%
Piccadilly	WPCY	Urban	2.40%	2.40%	2.40%

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	2.40%	2.40%	2.40%
Rivervale	WRVE	Urban	2.40%	2.40%	2.40%
Rockingham	WROH	Urban	2.40%	2.40%	2.40%
Shenton Park (Old)	WSPA	Urban	2.40%	2.40%	2.40%
Shenton Park (New AA5)	WSPK	Urban	2.40%	2.40%	2.40%
Sth Ftle Power Station	WSFT	Urban	2.40%	2.40%	2.40%
Southern River	WSNR	Urban	2.40%	2.40%	2.40%
Southern Cross	WSNX	Mixed	2.40%	2.40%	2.40%
Tate Street	WTTS	Urban	2.40%	2.40%	2.40%
University	WUNI	Urban	2.40%	2.40%	2.40%
Victoria Park	WVPA	Urban	2.40%	2.40%	2.40%
Waikiki	WWAI	Urban	2.40%	2.40%	2.40%
Wangara	WWGA	Urban	2.40%	2.40%	2.40%
Wanneroo	WWNO	Urban	2.40%	2.40%	2.40%
Welshpool	WWEL	Urban	2.40%	2.40%	2.40%
Wembley Downs	WWDN	Urban	2.40%	2.40%	2.40%
Willetton	WWLN	Urban	2.40%	2.40%	2.40%
Yokine	WYKE	Urban	2.40%	2.40%	2.40%

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	2.40%	2.39%
Mining	2.39%	2.39%

Mixed	2.41%	2.38%
Rural	2.46%	2.53%

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	2.39%	2.38%
Mining	2.49%	2.38%
Mixed	2.42%	2.39%
Rural	2.43%	2.36%

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.1.2¹².

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 prices¹³

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

¹² <https://www.erawa.com.au/cproot/20419/2/ERA-Approved---Appendix-E---Reference-Services.pdf>

¹³ 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	11.80%
RT14	11.80%
RT15	-
RT16	-
RT17	11.80%
RT18	11.80%
RT19	11.80%
RT20	11.80%
RT21	11.80%
RT22	11.80%
RT34	11.80%
RT35	11.80%
RT36	11.80%
RT37	11.80%
RT38	11.80%
RT39	11.80%
RT40	11.80%
RT41	11.80%
TRT1, TRT2 and TRT3	7.40%

Table A.5.17: Metering reference service prices

Metering Reference Service	(c/revenue meter/day)
M1	11.80%
M2	11.80%
M3	11.80%
M4	11.80%
M5	11.80%
M6	11.80%
M7 - SIM	11.80%
M7 - AMI	11.80%
M8	11.80%
M9	11.80%
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	11.80%
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	0.52%

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	2.40%
>=7,000 kVA	2.40%

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	2.40%	2.40%

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	4.21%

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	7.40%
Alcoa Pinjarra	WAPJ	7.40%
Amherst	WAMT	7.40%
Arkana	WARK	7.40%
Australian Fused Materials	WAFM	7.40%
Australian Paper Mills	WAPM	7.40%
Baandee (WC)	WBDE	7.40%
Balcatta	WBCT	7.39%
Beckenham	WBEC	7.40%
Beechboro	WBCH	7.39%
Beenup	WBNP	7.40%
Belmont	WBEL	7.40%
Bentley	WBTY	7.40%
Bibra Lake	WBIB	7.39%
Binningup Desalination Plant	WBDP	7.40%
Black Flag	WBKF	7.40%
Boddington	WBOD	7.39%
Boddington Gold Mine	WBGM	7.39%
Boulder	WBLD	7.40%
Bounty	WBNY	7.40%
Bridgetown	WBTN	7.40%
British Petroleum	WBPM	7.40%
Broken Hill Kwinana	WBHK	7.39%

Substation	TNI	Use of System Price (c/kW/day)
Bunbury Harbour	WBUH	7.41%
Busselton	WBSN	7.40%
Byford	WBYF	7.39%
Canning Vale	WCVE	7.40%
Capel	WCAP	7.41%
Carrabin	WCAR	7.40%
Cataby Kerr McGee	WKMC	7.40%
Chapman	WCPN	7.40%
Clarence Street	WCLN	7.40%
Clarkson	WCKN	7.41%
Cockburn Cement	WCCT	7.40%
Cockburn Cement Ltd	WCCL	7.39%
Collie	WCOE	7.40%
Collier	WCOL	7.40%
Cook Street	WCKT	7.39%
Coolup	WCLP	7.40%
Cottesloe	WCTE	7.40%
Cunderdin	WCUN	7.40%
Darlington	WDTN	7.39%
Edgewater	WEDG	7.39%
Edmund Street	WEDD	7.40%
Eneabba	WENB	7.40%
Forrest Ave	WFRT	7.40%
Forrestfield	WFFD	7.41%
Geraldton	WGTM	7.40%
Glen Iris	WGNI	7.39%
Golden Grove	WGGV	7.40%
Gosnells	WGNL	7.41%
Hadfields	WHFS	7.40%
Hay Street	WHAY	7.40%
Hazelmere	WHZM	7.40%
Henley Brook	WHBK	7.40%
Herdsmen Parade	WHEP	7.40%

Substation	TNI	Use of System Price (c/kW/day)
Joel Terrace	WJTE	7.40%
Joondalup	WJDP	7.41%
Kalamunda	WKDA	7.40%
Katanning	WKAT	7.40%
Kellerberrin	WKEL	7.40%
Kewdale	WKDL	7.40%
Kojonup	WKOJ	7.40%
Kondinin	WKDN	7.40%
Kwinana Alcoa	WAKW	7.37%
Kwinana Desalination Plant	WKDP	7.39%
Kwinana PWS	WKPS	7.38%
Landsdale	WLDE	7.40%
Maddington	WMDN	7.40%
Malaga	WMLG	7.39%
Mandurah	WMHA	7.41%
Manjimup	WMJP	7.40%
Manning Street	WMAG	7.40%
Margaret River	WMRV	7.40%
Marriott Road	WMRR	7.42%
Marriott Road Barrack Silicon Smelter	WBSI	7.39%
Mason Road	WMSR	7.42%
Mason Road CSBP	WCBP	7.40%
Mason Road Kerr McGee	WKMK	7.38%
Meadow Springs	WMSS	7.40%
Medical Centre	WMCR	7.40%
Medina	WMED	7.41%
Merredin 66kV	WMER	7.40%
Midland Junction	WMJX	7.40%
Milligan Street	WMIL	7.39%
Moora	WMOR	7.40%
Morley	WMOY	7.41%
Mt Barker	WMBR	7.40%
Muchea	WMUC	7.40%

Substation	TNI	Use of System Price (c/kW/day)
Muchea Kerr McGee	WKMM	7.40%
Muja PWS	WMPS	7.38%
Mullaloo	WMUL	7.40%
Mundaring Weir	WMWR	7.40%
Munday	WMDY	7.40%
Murdoch	WMUR	7.39%
Myaree	WMYR	7.40%
Narrogin	WNGN	7.40%
Nedlands	WNED	7.39%
North Beach	WNBH	7.39%
North Fremantle	WNFL	7.40%
North Perth	WNPH	7.40%
Northam	WNOR	7.40%
Nowgerup	WNOW	7.40%
O'Connor	WOCN	7.41%
Osborne Park	WOPK	7.40%
Padbury	WPBY	7.39%
Parkeston	WPRK	7.40%
Parklands	WPLD	7.40%
Piccadilly	WPCY	7.40%
Picton 66kv	WPIC	7.39%
Pinjarra	WPNJ	7.39%
Rangeway	WRAN	7.40%
Regans	WRGN	7.40%
Riverton	WRTN	7.40%
Rivervale	WRVE	7.40%
Rockingham	WROH	7.40%
Sawyers Valley	WSVY	7.40%
Shenton Park	WSPA	7.39%
South Fremantle 22kV	WSFT	7.41%
Southern River	WSNR	7.39%
Summer St	WSUM	7.40%
Sutherland	WSRD	7.40%

Substation	TNI	Use of System Price (c/kW/day)
Tate Street	WTTS	7.40%
Three Springs	WTSG	7.40%
Three Springs Terminal (Karara)	WTST	7.40%
Tomlinson Street	WTLN	7.39%
University	WUNI	7.40%
Victoria Park	WVPA	7.41%
Wagerup	WWGP	7.41%
Wagin	WWAG	7.40%
Waikiki	WWAI	7.41%
Wangara	WWGA	7.40%
Wanneroo	WWNO	7.40%
Wellington Street	WWNT	7.40%
Welshpool	WWEL	7.40%
Wembley Downs	WWDN	7.41%
West Kalgoorlie	WWKT	7.40%
Western Collieries	WWCL	7.40%
Western Mining	WWMG	7.41%
Westralian Sands	WWSD	7.40%
Willetton	WWLN	7.40%
Worsley	WWOR	7.38%
Wundowie	WWUN	7.40%
Yanchep	WYCP	7.39%
Yerbillon	WYER	7.40%
Yilgarn	WYLN	7.40%
Yokine	WYKE	7.40%

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	7.41%
Alcoa Pinjarra	WAPJ	7.38%
Badgingarra	WBGA	7.38%

Substation	TNI	Use of System Price (c/kW/day)
Bluewaters	WBWP	7.41%
Boulder	WBLD	7.41%
Cockburn PWS	WCKB	7.41%
Collgar	WCGW	7.39%
Collie PWS	WCPS	7.39%
Emu Downs	WEMD	7.38%
Geraldton	WGTN	7.45%
Greenough Solar Farm	TMGS	7.45%
Kemerton PWS	WKEM	7.41%
Kwinana Alcoa	WAKW	7.43%
Kwinana BESS (KBESS)	WKWB	n/a
Kwinana Donaldson Road	WKND	7.43%
Kwinana PWS	WKPS	7.41%
Kwinana Waste to Energy	WKWW	n/a
Landwehr (Alinta)	WLWT	7.38%
Mason Road	WMSR	7.43%
Merredin Power Station	TMDP	7.40%
Merredin Solar Farm	WMSF	7.40%
Muja PWS	WMPS	7.39%
Mumbida Wind Farm	TMBW	7.39%
Mungarra GTs	WMGA	7.41%
Newgen Kwinana	WNGK	7.40%
Newgen Neerabup	WGNN	7.41%
Oakley (Alinta)	WOLY	7.39%
Parkeston	WPKS	7.39%
Pinjar GTs	WPJR	7.38%
Tiwest GT	WKMK	7.36%
Wagerup	WWGP	7.40%
Walkaway Windfarm	WWWF	7.40%
Warradarge Wind Farm	WWDW	7.38%
West Kalgoorlie GTs	WWKT	7.40%
Worsley	WWOR	7.39%

Substation	TNI	Use of System Price (c/kW/day)
Yandin Wind Farm	WYDW	7.41%

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	7.43%

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)	7.45%

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)	7.42%