Appendix F.4

2018/19 Price List Information

Revised proposed access arrangement

14 June 2018

Access arrangement for the period
1 July 2017 to 30 June 2022

westernpower

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Appendix F.4

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Contents

1. Introduction

This document is Western Power's Price List Information, as defined in the *Electricity Networks Access Code 2004* (Code), to apply from 1 July 2018 or as approved by the Economic Regulation *Authority* (the *Authority*).

This document details:

- the history of the network tariffs
- the Price List's compliance with the *access arrangement*
- the objectives and principles that underlie Western Power's approach to deriving the reference tariffs
- the methodology of deriving cost of supply and the reference tariffs from the target revenue.

1.1 Code Requirements

Section 8.1 of the *Code* requires Western Power to submit *Price List Information* to the *Authority*.

The *Code* defines *Price List Information* as:

> "price list information" means a document which sets out information which would reasonably be required to enable the *Authority*, users and applicants to:
>
> a. Understand how the service provider derived the elements of the proposed price list; and
>
> b. Assess the compliance of the proposed price list with the *access arrangement*.

The *access arrangement* specifies the revenue cap form of price control and details the revenue that Western Power is able to earn in each year of the *access arrangement* period. The *access arrangement* contains the detailed price control formula that is applied each year to determine the network tariffs. Network tariffs are set each year to recover no more than the revenue cap. The revenue cap is the sum of:

- Western Power's revenue requirement contained in the *access arrangement* plus
- an adjustment for any previous year revenue over or under-recoveries (known as the k-factor adjustment) plus
- an adjustment for the Tariff Equalisation Contribution (TEC)

The *access arrangement* requires Western Power to seek the *Authority*'s approval each year for the price list.

1.2 2018/19 Foreword

This section details a number of matters that relate specifically to the preparation of the 2018/19 Price List.

1.2.1 Price List forms part of revised proposal

The 2018/19 Price List forms part of Western Power's revised proposal for the fourth *access arrangement* period (AA4). It covers the balance of the 2018/19 financial year from the AA4 commencement date until the end of the financial year, however the exact date of commencement will be decided as part of the *Authority*'s decision making process. Due to delays with the commencement of the AA4 process, there was no 2017/18 Price List produced in April 2017, with the 2016/17 Price List remaining in place. The access arrangement includes a 2017/18 Price List (attached at appendix F.1) however this is just the 2016/17 Price List, repurposed. The 2017/18 Price List will remain in force until the AA4 commencement date.

1.2.2 Modelling a mid-year price change

The access arrangement contains revenue caps for the whole of 2018/19. However, the financial year is split into two parts for pricing purposes: the first part commences on 1 July 2018 and involves no changes to existing tariffs; the second part will begin on 1 November 2018. The prices due to commence from 1 November are calculated such that the total revenue earned throughout 2018/19 is equal to the 2018/19 approved revenue caps.

As the pricing model requires annual revenue targets, where applicable (and noted) elsewhere in this document, revenues and costs have been converted to an 'annualised' dollar amount.

1.2.3 Metering pricing

For this revised proposal, the prices for distribution metering will now be split into two charges:

- For accumulation or Advanced Metering Installations (AMI)
- For interval meters (that are not AMI).

The costs involved in reading interval meters are higher than for accumulation meters and are priced accordingly. The largest contributor to this cost difference is the reading costs; manual reads involve higher labour costs (as the data is time consuming to extract), and for remotely read (non-AMI) meters the higher costs are attributable to the costs of the monthly data transmission via sim cards.

Distribution metering revenue is part of the distribution revenue cap, however section 4.5.1 details how the distribution revenue cap is allocated between metering and other revenue components.

1.2.4 Streetlight pricing

As discussed in the revised access arrangement information, Western Power is adopting a new replacement strategy for the AA4 period.

As is the case for metering above, streetlight revenue is recovered within the distribution revenue cap and is detailed in section 4.5.1.

1.2.4.1 Revised roll out and replacement strategy

Western Power is currently evaluating its luminaire replacement strategy. Our preferred position is light emitting diode (LED) streetlight replacements as the default for failed luminaries. In the event of a lamp failure, Western Power will continue to replace the lamp with a traditional lamp equivalent.

Western Power will also offer customers LED equivalent option for all current streetlight types for State Underground Power Program (SUPP) and new subdivision applications.

We do not expect there to be a significant variation in forecast costs as the take-up of LEDs as a proportion of the entire streetlight population will not be material during the AA4 period. LED luminaires installed during the AA4 period are not expected to have a materially different maintenance requirement, therefore no change to the streetlight opex allowance has been included in this revised AA4 proposal

1.2.4.2 LED streetlight options

The table below outlines the LED streetlight models and Western Power's tariff prices that will be available during the AA4 period:

Table 1.1: LED Models and Tariffs

LED Streetlight	Wattage	Price (c/day)
Standard LED	20	26.66
Standard LED	36	26.66
Standard LED	53	26.72
Standard LED	80	26.64
Standard LED	160	27.38
Standard LED	170	27.38
Decorative Bourke Hill LED	17	33.16
Decorative LED	42	33.16
Decorative Kensington LED	17	34.51
Decorative LED	34	34.47
Decorative LED	80	35.24
Decorative LED	100	37.23
Decorative LED	155	37.23

The table below shows the mapping of LED streetlight equivalents against Western Power's currently installed streetlight assets.

Table 1.2: LED Equivalents Mapped Against Current Luminaire Types

Light specification	Wattage	Standard/Decorative	Wattage
42W CFL BH	42	Decorative Bourke Hill LED	17
42W CFL SE	42	Standard LED	20
42W CFL KN	42	Decorative Kensington LED	17
150W HPS	150	Standard LED	80
	150	Decorative LED	80
250W HPS	250	Standard LED	170

Light specification	Wattage	Standard/Decorative	Wattage
	250	Decorative LED	155
70W HPS	70	Standard LED	36
	70	Decorative LED	42
	70	Decorative LED	34
125W MV	125	Standard LED	53
	125	Decorative LED	42
150W MH	150	Standard LED	80
	150	Decorative LED	80
250W MH	250	Standard LED	160
	250	Decorative LED	100
70W MH	70	Standard LED	36
	70	Decorative LED	42
	70	Decorative LED	34
40W FLU	40	Standard LED	20
100W INC	100	Decorative Kensington LED	17
50W MV	50	Standard LED	20
80W MV	80	Standard LED	20
250W MV	250	Standard LED	170
22W LED	18	Standard LED	20

1.2.5 Changes to the Excess Network Usage Charge

As discussed in attachment 11.1 of the initial AA4 proposal, Western Power is proposing changes to the way that use of the network in excess of contracted values is charged. Excess Network Usage Charges (ENUC) apply when a customer exceeds their contracted maximum demand (for a load) or their declared sent out capacity (for a generator). The ENUC is there to incentivise customers to operate within the contracted values as these are the values used when planning and operating the network.

However, Western Power recognises that not all instances of exceedance have equal impact. That is, there are some parts of the network where a demand increase would not have an impact on the safety or reliability of the network. The way the ENUC has been applied over the AA3 period does not make that distinction. To address this concern, Western Power is proposing to introduce a more nuanced ENUC. The new charges will consider the location of the customer, making the signal clearer and fairer. Each year, Western Power produces a State of the Infrastructure Report, this document includes discussion on which parts of the transmission network that are constrained. It is these areas that the revised ENUC will focus on.

In line with the most recent version of the report[1], for the 2018/19 Price List, the ENUC will be higher for customers in the goldfields region and connected to the Albany substation. Other customers will see a reduction in the ENUC.

1.3 Revenue requirement for 2018/19

The following sections detail the calculation of the revenue requirements for Western Power's Transmission and Distribution networks.

1.3.1 Maximum Transmission Regulated Revenue

The following table demonstrates the derivation of the maximum transmission regulated revenue for 2018/19 in accordance with section 5.6.6 of the *access arrangement*.

Table 1.3 – Maximum Transmission Regulated Revenue for 2018/19 ($M real as at 30 June 2017)

Transmission Revenue	2018/19
TR_t	302.7
plus TK_t	0.0
MTR_t	302.7

The derivation of the transmission system cost of supply cost pools and tariffs require the reference service revenue as an input in nominal terms. The following table details the transmission reference service revenue in nominal terms (please see section 1.3.3 for details of the inflation factor used). Also shown is the revenue cap converted to an annualised value for pricing.[2]

Table 1.4 - Transmission Revenue Cap Revenue for 2018/19 ($M)

Transmission Revenue	Revenue (Real)	Revenue (Nominal)
Revenue Cap Revenue ($MTR_{2018/19}$)	302.7	314.0
Revenue Cap Revenue - annualised		326.5

1.3.2 Maximum Distribution Regulated Revenue

The following table demonstrates the derivation of the maximum distribution regulated revenue for 2018/19 in accordance with section 5.7.6 of the *access arrangement*.

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[1] Published on Western Power's website: https://westernpower.com.au/media/2355/state-of-the-infrastructure-report-2016.pdf

[2] Of the $314M revenue in 2018/19, $217.7M is recovered between November – June. Dividing by 8 (months) and multiplying by 12 (months) converts this number to $326.5M as shown.

Table 1.5 – Maximum Distribution Regulated Revenue for 2018/19 ($M real as at 30 June 2017)

Distribution Revenue	2018/19
DR_t	1,001.4
plus DK_t	0
MDR_t (not including TEC_t)	1,001.4
TEC_t ($M nominal)	198.0

The derivation of the distribution system cost of supply cost pools and tariffs require the reference service revenue as an input in nominal terms. The following table details the distribution reference service revenue in nominal terms (please see section 1.3.3 for details of the inflation factor used). Also shown is the revenue cap converted to an annualised value for pricing.[3]

Table 1.6 - Distribution Revenue Cap Revenue for 2018/19 ($M)

Distribution Revenue	Revenue (Real)	Revenue (Nominal)
MDR_t (not including TEC_t)	1,001.4	1,038.5
Revenue Cap Revenue ($MDR_{2018/19}$)		1,236.5
Revenue Cap Revenue - annualised		1,248.7

1.3.3 Derivation of Inflation Factor

In sections 1.3.1 and 1.3.2 Western Power has inflated the reference service revenue from real terms to nominal terms by using real and forecast inflation in accordance with sections 5.6.6 and 5.7.6 of the *access arrangement*.

Table 1.7 - Derivation of 2018/19 Inflation Factor

December 2016 – December 2017 – Forecast	1.84%
December 2017 – December 2018 – Forecast	1.84%
Derived Inflation Factor	1.037

1.4 Forecast revenue recovery

The following table sets out the reference service revenue, by tariff, which is forecast to be collected when applying the 2018/19 Price List. Note the new reference tariffs are showing zero volumes as there are unlikely to be any customers on these reference services at 1 November 2018. The new reference services require a remotely communicating advanced meter to be installed.

[3] Of the $1,236.5M revenue in 2018/19, $832.4M is recovered between November – June. Dividing by 8 (months) and multiplying by 12 (months) converts this number to $1,248.7M as shown.

Table 1.8 – Reference Service Revenue Forecast in 2018/19 ($M Nominal, annualised values)

Reference Tariff	kWh	Customer Numbers	Forecast Transmission Revenue Recovered	Forecast Distribution Revenue Recovered
TRT1 – Transmission Exit	N/A	31	37.2	0.0
TRT2 – Transmission Entry	N/A	31	49.6	0.0
RT1 - Anytime Energy (Residential)	4,234,000,000	803,987	71.1	572.7
RT2 - Anytime Energy (Business)	1,051,000,000	73,608	20.9	151.0
RT3 - Time of Use Energy (Residential)	60,000,000	7,993	1.0	6.6
RT4 - Time of Use Energy (Business)	965,000,000	9,760	18.9	90.3
RT5 - High Voltage Metered Demand	672,000,000	288	8.1	26.3
RT6 - Low Voltage Metered Demand	2,029,000,000	3,901	32.8	125.0
RT7 - High Voltage Contract Maximum Demand	3,089,000,000	285	55.6	55.1
RT8 - Low Voltage Contract Maximum Demand	196,000,000	57	4.0	9.7
RT9 – Streetlighting	134,000,000	272,664	1.4	41.2
RT10 - Unmetered Supplies	37,000,000	16,198	0.3	4.8
RT11 - Distribution Entry	-	20	1.3	2.2
RT13 – Anytime Energy (Residential) Bi-directional Service	1,012,000,000	204,050	17.0	141.0
RT14 – Anytime Energy (Business) Bi-directional Service	59,000,000	1,363	1.2	6.5
RT15 – Time of Use (Residential) Bi-directional Service	53,000,000	9,631	0.8	6.5
RT16 – Time of Use (Business) Bi-directional Service	102,000,000	548	2.0	9.0
RT17 - Time of Use Energy (Residential)	0	0	-	-
RT18 - Time of Use Energy (Business)	0	0	-	-
Total Reference Service Revenue	**13,693,000,000**	**1,404,415**	**323.0**	**1,248.0**
Standby Services	-	-	3.5	0.7
TOTAL REVENUE CAP REVENUE			**326.5**	**1,248.7**
Over/(Under) recovery compared to maximum transmission/distribution regulated revenue			0	0

2. Pricing Principles Overview

This section discusses the principles, objectives and an overview of the methodology used in determining the reference tariffs.

2.1 Pricing Objectives

Reference service revenue is recovered through a set of reference tariffs that have been designed to meet high-level objectives described below. These objectives have been updated for the AA4 period.

Table 2.1: Pricing Objectives

Theme	Pricing objectives
Revenue sufficiency	Tariffs should be formulated to recover revenue from users in a manner that achieves: • sufficient revenue to provide a safe and reliable network • efficient network services to all network users • sufficient revenue to recover the revenue allowance defined in the price control.
Network efficiency	Tariffs must send appropriate and effective signals to promote the economically efficient investment in, operation and use of the Western Power Network. Tariff signals will include the objective of: • informing network users of their impact on existing and future network capacity and costs • assisting in managing growth in peak demand (to avoid increases in capital expenditure requirements) • providing network users with an incentive to shift their loads away from peak to off-peak periods. Tariffs will be cost reflective by: • reflecting the actual long run, time-varying cost of service provision to network users • individual charging parameters within each tariff taking account of the long run marginal costs.
Choice	Tariffs should provide network users with tariff choices that enable them to manage their costs
Simplicity	Be simple and straightforward, readily understood by customers and minimise administration costs, as far as is reasonable taking into account other objectives

2.2 Pricing Methods

The pricing methods (cost allocations) are set out in section 6.5 of the *access arrangement*. This section provides a summary of Western Power's pricing methods.

2.2.1 General

Reference tariffs aim to reasonably reflect the cost of providing the network service to users. The first step in developing reference tariffs is to model the cost of supply for users. The cost of supply cannot be derived at an individual customer level and so customers are categorised into a number of groups with similar costs.

Reference tariffs will generally have a number of components, which fall into fixed and variable categories. Fixed components would generally be a charge per user regardless of their size whereas the variable component would be related to energy or demand. These categories of costs reflect the fact that costs will be related either to the number of users serviced or to the amount of capacity provided.

The two processes of 'determining cost of supply' and 'setting reference tariffs' to recover those costs are separated so the costs of supply can be allocated to particular customer groups and the reference tariffs can be set to recover those costs. The costs are separated into fixed and variable components and the reference tariffs are similarly split so that fixed costs are recovered by fixed charges and variable costs by variable charges.

It is recognised the determination of the cost of supply for users and respective reference tariffs is an inexact process. A number of simplifying assumptions are required, for example, to categorise users into a small number of customer groups or classes with similar characteristics.

It is also noted that demand is the best measurement of capacity. However, the vast majority of users have energy only metering (or no metering at all) that does not record demand, and therefore energy is used as a proxy for demand.

2.2.2 Process to Determine Cost of Supply

This section presents an overview of the process to derive the cost of supply. Detailed information on this process is provided in sections 3 and 4.

There are two basic stages in determining the cost of supply for users:

- determination of the reference service revenue for Western Power; and
- allocation of the revenue components to different cost pools for various customer groups, based on factors such as supply voltage, location and load characteristics.

Note: Transmission and distribution are treated separately and each has independent target revenues.

The reference service revenue requirement must then be allocated to asset classes and the use of the assets allocated to users. The customer groups used in the analysis and modelling of costs generally reflect the nature of the physical connection to the network and the relative size and nature of the user, namely:

Transmission connected:

- Transmission Generation
- Transmission Loads

Distribution connected:

- High Voltage >1 MVA maximum demand
- High Voltage <1 MVA maximum demand
- Low Voltage >1 MVA maximum demand
- General Business Large (300 to < 1,000 kVA maximum demand)
- General Business Medium (100 to < 300 kVA maximum demand)
- General Business Small (15 to < 100 kVA maximum demand)
- Small Business (<15 kVA maximum demand)
- Residential
- Streetlights
- Unmetered Supplies

2.2.3 Process to Determine Reference Tariffs

This section presents an overview of the process by which reference tariffs are derived. Detailed information on the process is provided in sections 6 and 7.

The users within the customer groups are linked to reference tariffs so that cost of supply can then be derived for each reference tariff. The cost of supply is in terms of fixed and variable costs and price settings are then simply established to recover the cost pools from the users.

2.2.4 Modelling Cost Allocations

Western Power's transmission and distribution cost of supply (COS) models accurately reflect the network cost of supply for the various customer groups. The model assembles capital and operating costs for the components (lines, substations, transformers, etc.) of the modern equivalent assets employed in providing network capacity and delivering energy and allocates these to each customer group according to a pre-determined set of principles.

Tables from Western Power's COS model are provided in this document to demonstrate that Western Power complies with its cost allocation methodology.

3. Derivation of Transmission System Cost of Supply

This section details the derivation of the transmission system cost of supply for connection points on the transmission system.

3.1 Cost Pools

The following cost pools are used in the derivation of the transmission system cost of supply:

- Connection Services Cost Pool. Which is further allocated to the following cost pools:
  - Connection Services for Exit Points Cost Pool; and
  - Connection Services for Entry Points Cost Pool.
- Shared Network Services Cost Pool. Which is further allocated to the following cost pools:
  - Use Of System for Loads Cost Pool;
  - Use Of System for Generators Cost Pool; and
  - Common Service for Loads Cost Pool.
- Control System Services Cost Pool. Which is further allocated to the following cost pools:
  - Control System Services for Loads Cost Pool; and
  - Control System Services for Generators Cost Pool.

3.1.1 Connection Services for Exit Points Cost Pool

The Connection Services for Exit Points Cost Pool includes the Gross Optimised Deprival Value (GODV) of all connection assets at each Exit Point and one-third of the value of the voltage control assets at those points (since the function of voltage control equipment is partly location specific and partly system related).

3.1.2 Connection Services for Entry Points Cost Pool

The Connection Services for Entry Points Cost Pool includes the GODV of all connection assets at each Entry Point and one-third of the value of the voltage control assets at those points (since the function of voltage control equipment is partly location specific and partly system related).

3.1.3 Use of System for Loads Cost Pool

Use of System for Exit Points Cost Pool includes 50% of the total Shared Network Services Cost Pool.

3.1.4 Use of System for Generators Cost Pool

Use of System for Entry Points Cost Pool includes 20% of the total Shared Network Services Cost Pool.

3.1.5 Common Service for Loads Cost Pool

The Common Service for Loads Cost Pool includes:

- 30% of the total Shared Network Services Cost Pool;
- Shared Voltage Control Assets – two thirds of the value of voltage control assets at Entry and Exit points (since the function of voltage control equipment is partly location specific and partly system related) and the value of all of voltage control assets at transmission substations; and

- Adjustments for under or over recovery of revenue expected for any reason in any other tariff component.

3.1.6 Control System Service for Loads Cost Pool

The Control System Service for Loads Cost Pool consists of a portion of the total cost of all Supervisory Control and Data Acquisition (SCADA), SCADA related communications equipment, and costs associated with the control centre, proportioned based on the total number of points in the SCADA master station relevant to loads.

3.1.7 Control System Service for Generators Cost Pool

The Control System Service for Generators Cost Pool consists of a portion of the total cost of all SCADA, SCADA related communications equipment, and costs associated with the control centre, proportioned based on the total number of points in the SCADA master station relevant to generators.

3.2 Cost of Supply

In order to calculate transmission cost of supply, all transmission assets are valued and categorised into the above cost pools. Each network branch is further defined as either exit, entry or shared network and cost allocation is then applied based on the GODV of all relevant assets.

3.2.1 Transmission Assets

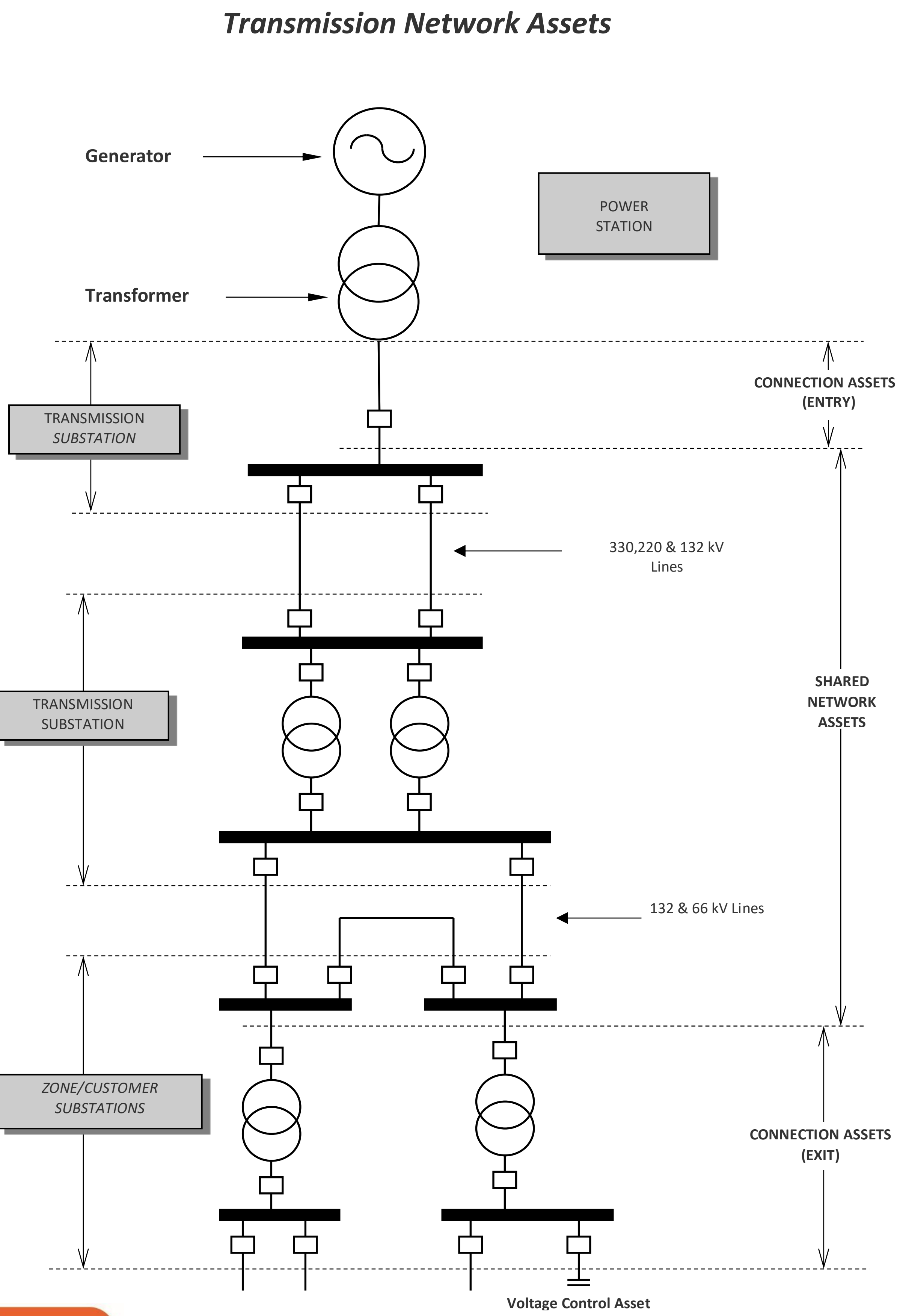
The principal elements of the transmission networks include transmission substations and zone substations, interconnected by transmission and sub-transmission lines. The transmission networks enable the transportation of electricity from power stations to zone substations and high voltage user loads. The zone substations provide the interface between the transmission network and distribution network.

Generally, the transmission networks assets comprise connection assets, shared network assets and other or ancillary assets. These are described as follows:

- Connection Assets: those assets at the point of physical interconnection with the transmission networks which are dedicated to a User - that is, at substations including transformers and switchgear, but excluding the incoming line switchgear. Connection assets for generators are referred to as entry assets and for loads they are called exit assets.
- Shared Network Assets: all other transmission assets, which are shared to some extent by network Users.
- Other or Ancillary Assets: network assets performing an Ancillary Services function comprise:
  - those providing a Control System Service, for example, system control centres, supervisory control and communications facilities.
  - those providing a Voltage Control Service in the networks, for example, a proportion of the costs of capacitor and reactor banks in substations.

Figure 1 shows, in simplified form, the principal elements of the transmission networks and the categorisation of the assets as described above.

Figure 1: Transmission Network Assets



3.2.2 Asset Valuation

All valuations of transmission assets are performed using the Optimised Deprival Value (ODV) methodology.

3.2.3 Valuation of Individual Branches and Nodes

To determine cost of supply, valuation data is required for every individual branch and node on the network. Every branch and node consists of many individual asset valuation building blocks that are all individually assessed.

Branches include transmission lines and transformers and include the substation circuits at each end. Each transmission line branch will typically have the cost of each of the circuit breakers at different substations included, whereas each transformer branch will typically have the cost of each of the circuit breakers at that same substation included.

Substation site establishment costs are allocated equally to all substation circuits.

The costs for shared circuit breakers (such as bus section breakers etc.) are allocated equally between all other substation circuits, which derive benefit from that shared circuit breaker.

3.3 Methodology of Allocating to Cost Pools

3.3.1 Overview

The methodology for allocating the transmission revenue to each cost pool is to allocate the revenue in the proportion to the GODV of the assets in each cost pool.

However, the annual revenue requirement for the Control System Service Cost Pool is calculated separately (using the same method as for all other network assets) but assuming higher depreciation and operating expenditure than for other network assets. When calculating other Cost Pool Revenues appropriate adjustments are required.

Consequently:

Cost Pool Revenue = RR * GODV (Cost Pool)

where:

RR = a revenue rate of return determined as $AARR_{network}$ / $\Sigma GODV_{network}$

$AARR_{network}$ = Transmission Reference Service Revenue excluding Annual Revenue Requirement for Control System Services.

GODV (Cost Pool) = GODV of the transmission network assets which belong in that cost pool.

$\Sigma GODV_{network}$ = GODV of all transmission assets excluding Control System Service assets

3.4 Cost Pool Allocations

Applying the above methodology, the following cost pool revenues were derived for 2018/19.

Table 3.1 - Transmission Pricing Cost Pools for 2018/19 ($M Nominal, annualised values)

Cost Pool	Allocated Revenue
Entry Connection	6.5
Exit Connection HV	0.5
Exit Connection LV	70.5
Control System Services for Generators	5.1
Control System Services for Loads	26.4
Use Of System for Generators	37.5
Use Of System for Loads	101.7
Common Service for Loads (including Voltage Control)	77.9
Metering CT/VT	0.4
Total Revenue Cap Revenue	**326.5**

4. Derivation of Distribution System Cost of Supply

This section details the derivation of the distribution system cost of supply for connection points on the distribution system.

The derivation of the distribution system cost of supply operates along the same principles as the transmission system. That is, the reference service revenue entitlement (which includes TEC) is determined for the distribution system, and that revenue is then allocated to asset categories to derive the cost of supply for each of the customer groups. The cost of supply is based on the relative usage of each asset category by the various customer groups.

The structure of the distribution network cost of supply and reference tariffs reflects the features of the distribution network.

4.1 Cost Pools

The distribution cost pools used in the distribution system cost of supply are:

- High Voltage Network
- Low Voltage Network
- Transformers
- Streetlight Assets
- Metering
- Administration

4.2 Customer Groups

The distribution customer groups used in the distribution system cost of supply are:

- High Voltage >1 MVA maximum demand
- High Voltage <1 MVA maximum demand
- Low Voltage >1 MVA maximum demand
- General Business Large (300 to < 1,000 kVA maximum demand)
- General Business Medium (100 to < 300 kVA maximum demand)
- General Business Small (15 to < 100 kVA maximum demand)
- Small Business (<15 kVA maximum demand)
- Residential
- Streetlights
- Unmetered Supplies

4.3 Locational Zones

Distribution reference tariffs are provided for individual locational zones for users with energy demands in excess of 1 MVA. Locational zones are defined as those areas supplied by the network where the distribution system cost of supply is similar. For example, the rural wheat belt areas of Western Australia are considered to have a reasonably uniform distribution system and costs of supply, as do the urban and CBD areas of Perth.

Zone substations with similar cost structures are allocated to locational zones that feed an area of the distribution system. Where a zone substation supplies an area of more than one distinct cost of supply, then all users supplied from that substation are considered to be in the one dominant category. That is, there is only one locational zone defined for each zone substation.

The five zones are defined in the sections below, and for details of the allocation of each zone substation to locational zones see the price list in the *access arrangement*.

4.3.1 CBD Locational Zone

This is defined as the intense business area generally recognised as the Perth CBD area. The defining street boundaries is generally from the Swan River north to Aberdeen Street Northbridge, west to Rokeby Road Subiaco, and east to the East Perth redevelopment area.

4.3.2 Urban Locational Zone

This is defined as the uniformly and continuously settled areas of Perth that contains the urban domestic, commercial and industrial users but exclude the CBD zone. This area also excludes the outer urban area that is treated as mixed. The country towns of Geraldton and Kalgoorlie are also included.

4.3.3 Rural Locational Zone

This is defined to include those areas which have a predominantly rural/farming characteristic and includes small to medium size towns within the southwest land division, for example Merredin.

4.3.4 Mixed Locational Zone

This is defined to include those areas that have a mixed user base that has at least two dominant load types, for example a mix of significant mining and rural loads or significant urban and rural loads. It also includes significant outer areas of Perth, which can be a mix of fringe urban, semi-rural and rural types, for example Yanchep.

4.3.5 Mining Locational Zone

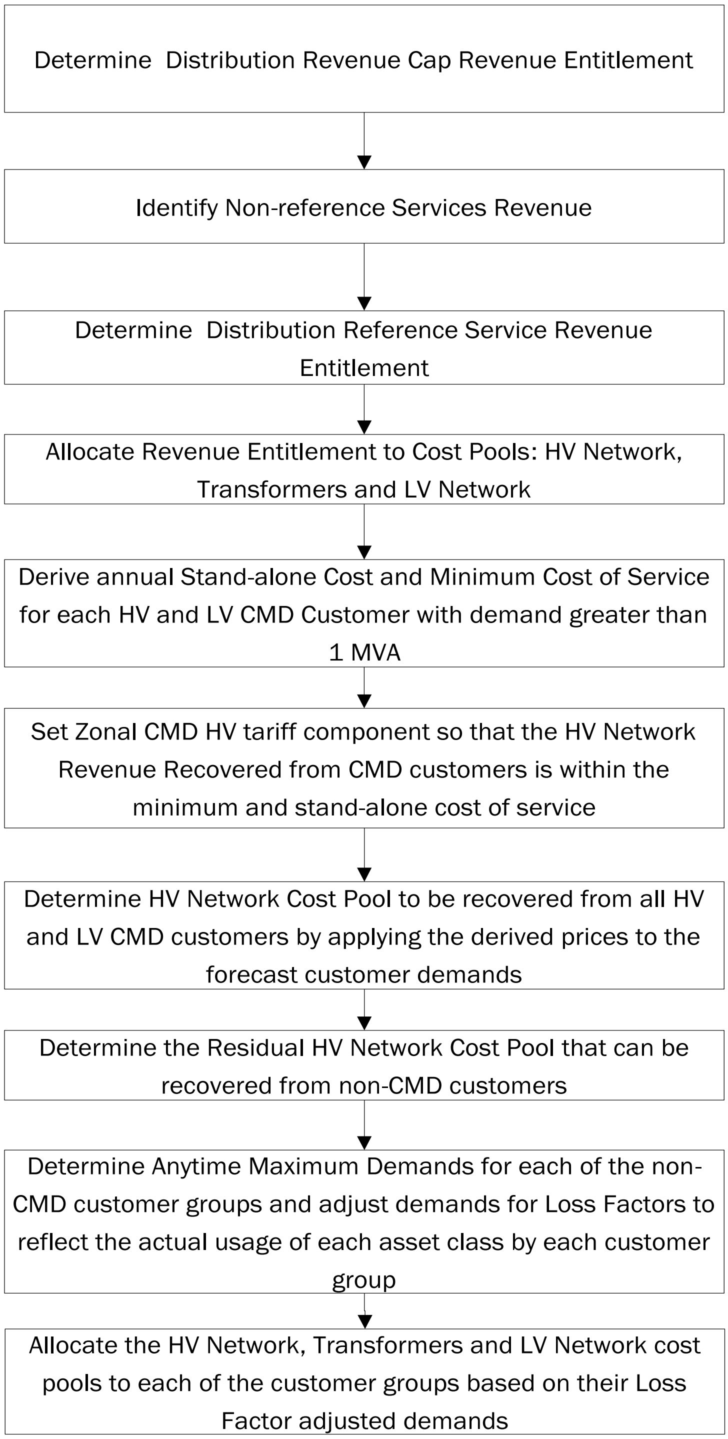
This is defined to include the mining area surrounding Kalgoorlie, which is supplied at 33 kV and the mining area at Forrestania which is also supplied at 33 kV. It does not include the town of Kalgoorlie (Urban zone).

4.4 Methodology of Deriving the Cost of Supply

4.4.1 Flowchart

The derivation of the cost of supply for each customer group is illustrated in the following flow diagram.

Figure 2: Distribution Cost of Supply Flow Chart



Each step in this process to derive the distribution cost of supply is described in more detail in the following sections.

4.4.2 Calculate the Forecast Distribution Network Revenue to be recovered from Distribution-Connected Users

The forecast distribution network revenue entitlement, determined in accordance with the approach approved by the *Authority* in the *access arrangement,* includes an amount for the TEC. The allocation of TEC to the cost pools and the customer groups is undertaken on the same basis as the network revenue entitlement set out below.

4.4.3 Allocate Revenue Entitlement to Cost Pools HV Network, Transformers and LV Network

The network revenue entitlement is then allocated to each of the asset classes being the High Voltage (HV) network, transformers and the Low Voltage (LV) network. The allocation is based on the GODV of each asset category as a proportion of the total GODV.

4.4.4 Derive HV annual stand-alone cost and incremental cost of supply for all HV and LV CMD users with demand greater than 1 MVA

In the cost of supply analysis, the costs for users with annual maximum demands less than 1,000 kVA are assumed to be uniform across the network whereas costs for users with demands above 1,000 kVA are determined on the basis of their location on the network and relative use of network assets.

On this basis, the HV network costs that can be allocated to users with maximum demands in excess of 1,000 kVA are calculated through a process that ensures the cost is between the incremental and stand-alone cost of supply. This approach is consistent with the requirements of section 7.3 of the *Code* and demonstrated in section 7.3.

In terms of costs of supply analysis, this approach is contrary to the approach for users with demands below 1,000 kVA. For these users the approach is facilitated by allocating the network costs on the basis of sharing the average costs of the network between users depending on their relative usage of the network components.

This approach for larger users can distort the final price outcomes because it assumes that costs can be allocated linearly on usage. This approach is reasonable for smaller users where the stand-alone cost will far exceed the average cost of supply. On the other hand, the stand-alone cost for larger users can be less than a simple linear allocation of costs and for this reason it is essential to take a different approach.

The approach taken is to derive the HV network incremental and stand-alone cost for each user with maximum demand in excess of 1,000 kVA. This process will give maximum and minimum revenues that could be recovered from this customer group.

The reality of network pricing is that the actual revenue recovered from these users should fall between these two values. The actual value is determined by deriving reference tariff components that, when applied to the forecast user data will produce charge and revenue outcomes that recover at least the incremental cost of supply but do not recover more than the stand-alone cost of supply. The detail of this price setting is contained in section 7.

4.4.5 Redefine Revenue Pools

The outcome of the process to date is that the HV network revenue for HV and LV users with maximum demands greater than 1,000 kVA has been forecast. This now results in a reallocation of the reference tariff revenue entitlement into the costs pools of:

- HV network cost pool that is recovered from users with demands greater than 1,000 kVA

- Residual HV network cost pool for users with demands less than 1,000 kVA
- Transformer cost pool
- LV network cost pool

These cost pools must now be allocated to customer groups based on relative usage of the network elements.

4.4.6 Allocation of Residual HV Network Costs to Customer Groups

This allocation is to reflect the usage of each of the customer groups of the HV network remembering that the costs associated with users with maximum demands greater than 1,000 kVA have already been determined.

The allocation is based on the diversified maximum demand imposed by each customer group. Where a user has a metered demand, that demand is recorded but for the vast majority of users there is no metered demand. For all of these users a notional demand is calculated based on their diversified load factor. Those calculated demands are adjusted by average loss factors to reflect the actual demand placed on the HV network.

The load factors are based on industry codes that reflect typical users. These load factors were derived from sample data taken over a large number of users and are recorded against each user. The sum of the demands is called the anytime maximum demand (ATMD).

The load factors that are used are listed by customer group as follows:

Table 4.1: Load Factor by Customer Group

Customer Group	Load Factor (%)
Unmetered	8
Streetlights	8
Residential	8
Small Business	8
General Business Small	8
General Business Medium	5
General Business Large	4
Low Voltage >1MVA	4
High Voltage	1

4.4.7 Fixed and Variable Costs

Based on the premise that the network was built in part to supply each user, it is reasonable to allocate some of the HV costs on a per user basis rather than purely on demand. Capacity to carry load should clearly be allocated on demand, but the cost to get a minimum capacity supply to a user should, in principle, simply be allocated on a per user basis. This reflects the principle that all users benefit from the HV line regardless of their actual usage.

The question of what percentage of costs should be allocated on a per user basis is the classical fixed and variable cost allocation issue. To determine the fixed component of the cost the approach taken will be to calculate the cost to establish the network to supply the smallest possible load to each user. The variable component of the cost can then be based on all costs that give the network capacity to provide differential supply to each user. This process is described below.

4.4.7.1 Capital related costs (return and depreciation)

The "minimal" cost HV line could be seen as a single-phase line with minimum conductor size, maximum bay lengths and minimum pole and hardware ratings. It is reasonable to assign 40 metre bays in the urban area and 250 metre bays in rural areas for this purpose. The approximate costs for such hypothetical constructions (derived from the results of the 2004 valuation study) would be as follows.

Table 4.2: Capital Related Costs

Line Construction	Cost per Kilometre ($)
1 Phase Steel (40 m bays)	18,000
3 Phase Large Size (40 m bays)	50,000
1 Phase Steel (250 m bays)	8,500
3 Phase Large Size (120 m bays)	24,000

From these numbers it is reasonable to deduce that the cost to provide a minimal HV supply is approximately 35% of the cost to provide a full capacity supply in both the urban and rural cases. The remaining 65% is therefore considered related to load and should be allocated on demand.

4.4.7.2 Operating and maintenance costs

A proportion of the costs associated with operations and maintenance do not vary with load, while other costs are determined to be load related.

A proportion of maintenance costs relating to routine inspection and repair could be regarded as being fixed in nature, whereas a proportion is required to maintain capacity, and therefore could be regarded as variable. Fault restoration work can be similarly differentiated, depending on the nature of the faults.

It is difficult to be definitive in allocating maintenance costs but a 50:50 split between fixed and variable is considered reasonable and has been adopted for cost allocation purposes.

4.4.7.3 Resultant cost allocation

Applying these percentage allocations to three phase HV capital and operational and maintenance costs results in a fixed to variable ratio of approximately 40:60.

4.4.8 Allocation of Transformer Costs to Customer Groups

Transformers are installed to provide capacity and energy for each load and the costs can be fairly allocated on demand.

The cost of maintenance of transformers is a very small proportion of the total distribution network maintenance expense, and so no maintenance costs are allocated to transformers.

4.4.9 Allocation of LV Network Costs to Customer Groups

The logic for developing cost allocation principles for LV network costs is identical to the HV case. Therefore, the LV costs are allocated on a similar basis.

However, the LV costs per kVA are generally higher for smaller users than for larger users. Larger users use proportionately less of the LV network because they are typically connected closer to transformers, and generally have a lower level of back-up. For example, a user with a load of 300 kVA or more would generally be connected directly to a transformer with limited capacity in the LV network to supply only part load in the event of an HV contingency.

Appropriate weighting factors have therefore been derived to reflect the proportionate usage of the LV network by the different customer groups, as follows:

Customer Group	Cost Weighting
Residential	1
Small Business	1
General Business - Small	1
General Business - Medium	0.9
General Business - Large	0.1
Low Voltage > 1 MVA	0.1
High Voltage	0

4.4.10 Allocation of TEC Costs to Customer Groups

TEC is allocated to the cost pools consistent with the methodology detailed above. TEC is then allocated to customers groups on the same basis that is set out above for:

- allocation of HV network costs to customer groups
- allocation of transformer costs to customer groups
- allocation of LV network costs to customer groups

4.4.11 Streetlighting Costs

Allocation of network costs to streetlighting is in two components - the use of network costs and the costs associated with the streetlight asset itself.

4.4.11.1 Use of Network Costs

Costs for the use of the HV and LV networks and transformers are allocated on a fixed and variable basis as for other customer groups, but with customer numbers reduced by a factor of 10.

4.4.11.2 Streetlight Asset Costs

Streetlighting costs are directly allocated to streetlights based on the share of the revenue cap that is directly attributable to streetlight maintenance. This calculation is shown in section 4.5.1.

4.4.12 Metering Costs

Similarly to streetlights, metering costs are allocated based on their share of the revenue cap, shown in section 4.5.1.

4.4.13 Administration Costs

The allocation of administration costs is based on specific charges for the larger customer groups, with the residual cost pool allocated by ATMD over the other customer groups.

4.5 Cost Pool Allocations

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

Table 4.3: Allocation of the Distribution Network Revenue Entitlement to Cost Pools

Customer group	ATMD MVA	GWh	Loss Adjusted ATMD's	Transformer Adjusted ATMD's	LV Adjusted ATMD's	Number of Customers	LV Adjusted Customer Numbers	High Voltage Network		Low Voltage Network		Transformers	Streetlight Assets	Metering	Administration
								Fixed $/annum	Variable $/annum	Fixed $/annum	Variable $/annum	Variable $/annum	Fixed		
Unmetered	6	37	6	6	6	16,345	16,345	2.1	0.4	1.5	0.3	0.2	0.0	0.0	0.7
Streetlights	34	134	37	37	4	280,437	28,044	3.8	2.5	2.2	0.2	1.3	28.4	0.0	2.0
Residential	2,040	5,302	2,135	2,135	2,135	1,045,638	1,045,638	139.0	148.4	83.1	114.7	78.2	0.0	26.0	101.2
Small Business	322	722	337	337	337	74,041	74,041	14.0	27.6	6.2	19.4	13.9	0.0	3.7	15.0
General Business - Small	532	1,192	556	556	556	13,045	13,045	2.2	46.5	1.1	32.2	23.3	0.0	2.1	21.8
General Business - Medium	470	1,055	486	486	437	2,931	2,637	0.5	40.2	0.2	25.6	20.4	0.0	1.2	19.1
General Business - Large	449	1,006	464	464	46	970	97	0.2	35.1	0.0	2.7	18.5	0.0	0.6	18.1
LV greater than 1 MVA	162	362	165	165	17	126	13	3.9	15.3	0.0	0.9	6.9	0.0	0.1	2.4
HV less than 1 MVA	78	279	79	0	0	149	0	0.0	4.3	0.0	0.0	0.0	0.0	0.2	2.4

Customer group	ATMD MVA	GWh	Loss Adjusted ATMD's	Transformer Adjusted ATMD's	LV Adjusted ATMD's	Number of Customers	LV Adjusted Customer Numbers	High Voltage Network		Low Voltage Network		Transformers	Streetlight Assets	Metering	Administration
								Fixed $/annum	Variable $/annum	Fixed $/annum	Variable $/annum	Variable $/annum	Fixed		
HV>1 MVA	1,038	3,083	1,095	0	0	406	0	22.4	39.7	0.0	0.0	0.0	0.0	0.6	6.2
TOTAL	**5,131**	**13,172**	**5,360**	**4,186**	**3,538**	**1,434,088**	**1,179,859**	**188.1**	**359.9**	**94.3**	**195.9**	**162.8**	**28.4**	**34.4**	**188.2**

Table 4.4 - Distribution Cost Pools for 2018/19 ($M Nominal, annualised values)

	Locational Zone					
Cost Pool	CBD	Urban	Goldfields Mining	Mixed	Rural	Total
High Voltage Network	12.8	194.9	4.6	127.6	132.3	472.2
High Voltage Network > 1 MVA	9.8	39.6	5.6	14.9	4.1	74.0
High Voltage Network Total	**22.6**	**234.5**	**10.2**	**142.5**	**136.4**	**546.2**
Low Voltage Network	12.6	203.1	1.7	52.2	19.6	289.2
Transformers	8.6	86.2	2.3	39.7	25.5	162.3
Streetlight Assets						28.4
Metering						34.4
Administration						188.2
Revenue requirement						1,248.7

4.5.1 Derivation of streetlight and metering asset cost pools

The costs for streetlight and metering shown in Table 4.4 are calculated using a similar approach as the overall revenue modelling approach taken to determine the transmission and distribution revenue caps. That is, using a building block approach to revenue. The cost pool is the sum of the:

- Return on assets (that is, the product of the rate of return with the Regulated Asset Base (RAB) of the assets);
- Depreciation (based on the regulated value of the assets and the expected life of the assets); and
- Operating expenditure approved.

Added to these costs are a portion of Western Power's overall tax building block and a portion of the recovery of deferred revenue. For a more detailed explanation of the building blocks, see Chapter 10 of the AAI for the initial proposal.

Table 4.5: Derivation of Streetlight and Metering Costs

2018/19 cost of service	Streetlights	Metering
Opening RAB	90.2	133.2
Return on asset	3.7	6.3
Depreciation	7.4	9.5
Opex	14.1	14.8
Indirect cost allocation	3.2	3.9
Cost of service	28.4	34.5

5. Reference Tariff Structure

This section provides an overview of the reference tariffs that apply to the transmission and distribution system.

5.1 Reference Services and Tariff Structure

The following table details the relationship between the reference services, detailed in the *access arrangement*, and the reference tariffs.

Table 5.1 - Reference Services

Reference Service	Reference Tariff
A1 – Anytime Energy (Residential) Exit Service	RT1
A2 – Anytime Energy (Business) Exit Service	RT2
A3 – Time of Use Energy (Residential) Exit Service	RT3
A4 – Time of Use Energy (Business) Exit Service	RT4
A5 – High Voltage Metered Demand Exit Service	RT5
A6 – Low Voltage Metered Demand Exit Service	RT6
A7 – High Voltage Contract Maximum Demand Exit Service	RT7
A8 – Low Voltage Contract Maximum Demand Exit Service	RT8
A9 – Streetlighting Exit Service	RT9
A10 – Unmetered Supplies Exit Service	RT10
A11 – Transmission Exit Service	TRT1
B1 – Distribution Entry Service	RT11
B2 – Transmission Entry Service	TRT2
C1 – Anytime Energy (Residential) Bi-directional Service	RT13
C2 – Anytime Energy (Business) Bi-directional Service	RT14
C3 – Time of Use (Residential) Bi-directional Service	RT15
C4 – Time of Use (Business) Bi-directional Service	RT16
C5 – High Voltage Metered Demand Bi-directional Service	RT5
C6 – Low Voltage Metered Demand Bi-directional Service	RT6
C7 – High Voltage Contract Maximum Demand Bi-directional Service	RT7
C8 – Low Voltage Contract Maximum Demand Bi-directional Service	RT8
D1 - 3 Part Time of Use Energy (Residential) Service	RT17

Reference Service	Reference Tariff
D2 - 3 Part Time of Use Energy (Business) Service	RT18

5.2 Exit Service Tariff Overview

An overview of the structure of each of the reference tariffs applicable to exit services is presented in the following sections.

5.2.1 RT1, RT2, RT 13 and RT14

The tariff structure for distribution includes:

- A fixed charge per user, and
- A charge per kWh for energy consumption.

The tariff structure for transmission includes:

- A charge per kWh for energy consumption.

Energy only tariffs have no incentive for users to improve their load factor or shift energy consumption to off-peak.

5.2.2 RT3, RT4, RT15 and RT16

The tariff structure for distribution includes:

- A fixed charge per user;
- A charge per kWh for metered on peak energy consumption; and
- A charge per kWh for metered off peak energy consumption.

The tariff structure for transmission includes:

- A charge per kWh for metered on peak energy consumption; and
- A charge per kWh for metered off peak energy consumption.

Time of use tariffs have the incentive for users to manage their energy consumption to shift energy consumption from on-peak to off-peak. However, as noted earlier, these time of use tariffs do not adequately reflect the actual peak periods of the network.

5.2.3 RT5 – High Voltage Metered Demand

The tariff structure is based on the metered demand of the user, with a discount to the demand charge based on the ratio of off-peak energy to total energy used. In addition the tariff has a demand length tariff component for users with demand greater than 1,000 kVA.

This tariff has a mix of incentives for the user to manage their electricity consumption.

The demand used is a running 12-month peak. This provides a clear incentive to manage the peak demand because any excessive demand recorded in one month then impacts upon the demand charge for the next 12 months. The demand length charge is also based on the running 12-month peak.

The second incentive is the off-peak energy discount which is based upon the ratio of off-peak energy to total energy used. The maximum discount is 30% for off-peak energy usage.

5.2.4 RT6 – Low Voltage Metered Demand

The tariff structure is identical to RT5 – High Voltage Metered Demand.

5.2.5 RT7 – High Voltage Contract Maximum Demand

The tariff structure requires the user to nominate a contracted maximum demand (CMD) that reasonably reflects their expected annual peak demand. In addition the tariff has a demand length tariff component also based on the CMD. There is a monthly penalty for any demand excursion above the CMD. All prices are in terms of $ per kVA.

The distribution component of the prices is zonal and there are 5 locational zones ranging from CBD to rural. This is because the costs of supply are seen to be dependent on the nature of the network that varies according to the location and consequent construction standard and cost.

There are also separate charges for administration and metering.

The transmission component of the tariff is nodal with prices based on the zone substation to which the user is connected.

This tariff has a mix of incentives for the user to manage their electricity consumption.

The demand is in kVA rather than kW so there is a clear benefit from managing the power factor as close to unity as possible. For example, improving the power factor from 0.7 to 0.8 will reduce the demand charge by 12.5%.

The second incentive is to manage the peak demand, which can be achieved by improving the load factor and by containing the peak demand. This incentive is very strong and the user has flexibility in the options available for managing the demand. The penalty for exceeding the contract maximum demand provides additional incentive.

The demand length charge provides an incentive for the user to locate as close as possible to the zone substation. For existing users there is no real opportunity to respond to this incentive, but for new users there is some ability to respond.

The transmission component of the price is nodal so that there is a clear signal for users to locate near to the lower price substations. This may or may not be achievable depending on the individual user circumstances.

5.2.6 RT8 – Low Voltage Contract Maximum Demand

The tariff structure is identical to RT7 – High Voltage Contract Maximum Demand with the addition of a low voltage charge that reflects the additional cost for usage of the low voltage distribution network.

5.2.7 RT9 – Streetlighting and RT10 – Unmetered Supplies

Streetlights and unmetered supplies do not have metering information to support either the initial setting of the tariff or the billing of users based on energy consumption or energy demand and therefore the energy consumption must be estimated based on burn hours and globe wattage.

The tariff structure for distribution includes:

- A fixed charge per user; and
- A charge per kWh for calculated energy consumption.

The tariff structure for transmission includes:

- A charge per kWh for calculated energy consumption.

Where the asset is a Western Power maintained streetlight, there is a charge to reflect the capital and operating costs of the streetlight asset itself, revenue to recover these costs are included within the revenue cap. The tariff structure for the streetlight asset is a fixed charge per light based on the type and rating of the light.

5.2.8 TRT1 – Transmission

The tariff is based on the zone substation to which the user is connected. The user will pay the use of system, common service and control system service charges. There is also a separate metering charge. All prices are in dollars per kW.

The tariff structure requires the user to nominate a CMD, in kWs, that reasonably reflects their expected annual peak demand. There is a monthly penalty for any demand excursion above the CMD.

The incentive is clearly for the user to manage their peak demand through the initial nomination of the CMD and also the monthly penalty for exceeding the CMD.

5.3 Entry Service Tariff Overview

An overview of the structure of each of the reference tariffs applicable to entry services is presented in the following sections.

5.3.1 RT11 – Distribution

The transmission charge is identical to the charge for a transmission connected generator in that the generator nominates a declared sent out capacity (DSOC) and the charge is based on the transmission nodal price at the nearest transmission entry point. The transmission charge for use of system is in dollars per kW. Unlike the transmission exit reference tariff (TRT1) there is no common service charge. The generator must also pay the connection charge which is also expressed in terms of $ per kW.

The generator's DSOC is in kW and is corrected for losses from the zone substation to the generator site, for purposes of calculation of the transmission price component.

The distribution charge is based on the zonal CMD demand length price. There is no demand only charge. As such the distribution charge for generators with demand less than 1,000 kVA is zero. There is also a separate metering charge.

The DSOC must be nominated in kW for the transmission charge and in kVA for the distribution charge. However the power factor is assumed to be unity for the purpose of charging because the power factor will not generally be within the control of the generator.

The incentive for distribution-connected generators is to locate as near as possible to the zone substation although for generators with a DSOC less than 1,000 kVA there is no such incentive. However, small generators are not considered to require strong locational incentives because the network will generally not be impacted to any significant extent.

The transmission component also contains a locational signal. Like for TRT2 customers, there is a monthly penalty for any demand excursion above the DSOC that has not been authorised by System Management.

5.3.2 TRT2 – Transmission

The tariff is based on the zone substation to which the generator is connected. The generator will pay the entry point use of system and control system service charges. There is also a separate metering charge. All prices are in dollars per kW.

The tariff structure requires the generator to nominate a DSOC, in kWs, that reflects their maximum intended export capacity. There is a monthly penalty for any demand excursion above the DSOC that has not been authorised by System Management.

6. Derivation of Transmission System Tariff Components

This section describes the methodology used to calculate transmission reference tariff components.

6.1 Cost Reflective Network Pricing

6.1.1 General

The Cost Reflective Network Pricing (CRNP) cost allocation method allocates the revenue requirement to all network elements, based on their GODV, then determines the use made of each network element by each connection point during the survey period.

The CRNP cost allocation process requires detailed network analysis and involves the following steps:

1. Determining the annual revenue requirement for individual transmission shared network assets (see below);
2. Determining the network load and generation pattern;
3. Performing a load-flow to calculate the MVA loading on network elements;
4. Determining the allocation of generation to loads;
5. Determining the utilisation of each asset on the network by each connection point;
6. Allocating the revenue requirement of individual network elements to each user based on the assessed usage share; and
7. Determining the total cost allocated to each connection point by adding the share of the costs of each individual network element attributed to each point in the network.

6.1.2 Allocation of Generation to Load

A major assumption in the use of the CRNP methodology is the allocation of generation to load using the 'electrical distance'. With this approach, a greater proportion of load at a particular location is supplied by generators that are electrically closer than those that are electrically remote. The electrical distance is the impedance between the two locations, and this can readily be determined through a standard 'fault level calculation'. Once the assumption has been made as to the proportion that each generator actually supplies each load for a particular load and generation condition (time of day) it is possible to trace the flow through the network that results from supplying each load (or generator).

The utilisation that any load makes of any element is then simply the ratio of the flow on the element resulting from the supply to this load to the total flow on the element made by all loads and generators in the system.

6.1.3 Operating Conditions for Cost Allocation

The choice of operating conditions is important in developing prices using the CRNP methodology. The use made of the network by particular loads and generators will vary depending on the load and generation conditions on the network at the time. The National Electricity Rules (NER) sets out principles that could be applied to determine the sample of operating conditions to consider.

The load and generation patterns used to establish transmission prices should include all operating scenarios that result in most stress in the network and for which network investment may be contemplated. The operating conditions chosen should broadly correspond to the times at which high demands drive network expansion decisions. Operating conditions should be included that impose peak loading conditions on particular elements, recognising that these may occur at times other than for peak demand.

Consistent with these principles, the operating conditions to be used for the cost allocation process for the transmission system are as follows:

- Load and generation conditions shall be actual operating conditions from 12 months prior; and
- Operating conditions shall include data for every node for every half hour where system peak demand is greater than an amount such that data from 10 individual summer days and 10 individual winter days are included.

6.2 Price Setting for Transmission Reference Services

Transmission tariffs for exit and entry services are fixed and are generally expressed as dollars/kw/annum. Generally, transmission prices are derived by dividing the cost pool, either in its entirety or at a zone substation level, by the assigned maximum demand applying to those assets. However, the details of some parts of the process are complex and explained in more detail in the following sections.

6.2.1 Transmission Pricing Model

Once Transmission assets are valued and T-price (see below for details) has established the relativity of Use of System (UOS) prices the Transmission Pricing Model is used:

1. to calculate the annual revenue requirements for all respective cost pools (based on valuation data and the rate of return required); and
2. to scale the raw T-price derived UOS prices to give the required UOS cost pool revenues.

6.2.2 Connection Price

The Connection Price is a price for the utilisation of Western Power owned connection assets. The Connection Price reflects the total annual costs allocated to the connection assets divided by the total usage at all points. The Connection Price is calculated by taking the Connection Cost Pool Revenue and dividing it by the aggregate of relevant CMDs and DSOCs (over all Exit or Entry points where the charge is applied).

Connection charges for connection points on the distribution system will be differentiated between loads and generators by applying the principles applied to the transmission shared system.[4] This results in generators paying approximately a quarter of the price as for loads.

Connection charges for connection points on the transmission system are not published but are determined subject to the specific connection arrangements. These connection charges are individually calculated to reflect the actual connection assets that apply to that user. The amount of the charge is based on achieving a regulated return on all relevant assets and an allocation of the transmission network operating costs.

4 By adopting the principle of 20 per cent of costs being allocated to generation and the remaining 80 per cent to loads.

6.2.3 UOS Prices

Consistent with the NER, the proportion of the transmission reference service revenue that is allocated to Transmission UOS is allocated to each and every connection point using a CRNP method. CRNP assigns a proportion of shared network costs to individual user connection points.

6.2.3.1 T-Price

Western Power uses T-price to establish the relativity of UOS prices for each exit and entry point. T-price is a modelling tool to allocate network costs using CRNP. T-price requires significant work to establish all of the inputs and to run the model, in summary:

- The GODV of every branch and node of the network is allocated. Every node is classified as either Exit or Entry, and every branch is classified as either shared or dedicated to consumers or dedicated to generators.
- Electrical configuration and parameters of the network are established (PSSE system Raw Data file).
- Interval data is assembled for all entry and exit points.
- Load flow analysis is carried out so that all network element costs are allocated to each zone substation based on usage of those network elements.
- The costs for all entry and exit points are then converted to prices by assigning a maximum demand to each node and using that demand to calculate a price in terms of dollars/kW/annum.

6.2.3.2 UOS Price Moderation

The application of CRNP for UOS prices can introduce volatility to individual prices as a result of changes in network usage beyond the control of any one user. It is hence appropriate to moderate any price fluctuations to mitigate price shock and improve certainty to customers. Annual variations to UOS prices are therefore scaled and moderated such that annual changes are constrained within a band of ± 5%.

6.2.4 Common Service Price for Loads

The Common Service Price is expressed in cents/kW/day and is uniform for all exit points. The Common Service Price is calculated by taking the Common Service Cost Pool Revenue and dividing it by the aggregate of relevant CMDs (over all Exit points where the charge is applied).

6.2.5 Control System Service Price

The Control System Service Price is expressed in cents /kW/day. Separate Prices for consumers and generators are calculated based on the respective cost pools but are uniform for each.

6.2.5.1 Control System Service for Loads

The Control System Services price for Loads is calculated by taking the Control System Services for Loads Cost Pool Revenue and dividing it by the aggregate of relevant CMDs (over all Exit points where the charge is applied).

6.2.5.2 Control System Service for Generators

The Control System Services price for Generators is calculated by taking the Control System Services for Generators Cost Pool Revenue and dividing it by the aggregate of relevant DSOCs (over all Entry Points where the charge is applied).

6.2.6 Transmission Tariff Setting

The following table details the forecast transmission revenue which will be collected from transmission connection points and the total amount that will be collected from distribution connection points (please see section 6.3 for further details).

Table 6.1 - Transmission Revenue Forecast for 2018/19 ($M Nominal, annualised values)

Customer type	Forecast Total MW	Number Customers	Forecast Transmission Revenue Recovered
Transmission Exit	710	28	37.2
Transmission Entry	5505	30	49.6
Distribution Users	3683		236.9
Transmission Standby			2.8
Total Revenue Cap Revenue			**326.5**

6.3 Price Setting for Distribution Reference Services

The tariffs for connection points on the transmission system do not collect the full transmission reference service revenue entitlement. Connection points on the distribution system utilise the transmission system as well as the distribution system. The remainder of the transmission reference service revenue entitlement is collected from tariffs for connection points on the distribution system.

Charges are determined for each direct connected transmission user based on respective CMDs. The revenue from these users is then deducted from the revenue entitlement for that substation to give a net revenue amount to be recovered from users connected to that substation via tariffs for connection points on the distribution system.

Reference tariffs for users connected to the distribution system with a peak demand >1 MVA incorporate transmission nodal prices. The transmission pass-through revenue, net of the revenues from the >1 MVA users, is then allocated in aggregate to the various small customer groupings on the basis of loss adjusted any time maximum demand (ATMD) for each grouping (further described below).

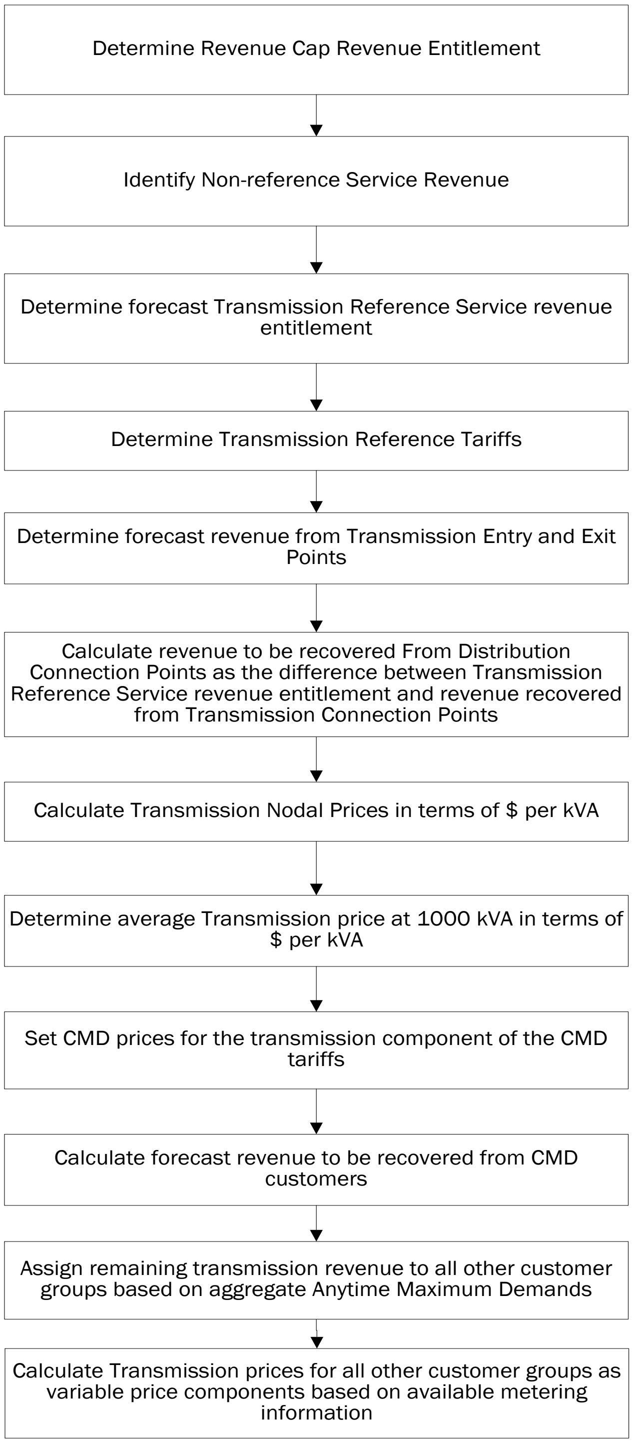
A number of processes take place to determine transmission prices that match the structure of distribution reference tariffs so that a full suite of bundled tariffs can be produced.

Transmission prices take a range of forms, as discussed in section 5. The CMD tariffs are based on a nominated peak demand in terms of kVA. The CMD tariffs are nodal in that they are based on the transmission node to which the load user is connected. All other tariffs are uniform across the Western Power Network.

6.3.1 Flow Chart

The process to derive prices is illustrated in the following flow diagram.

Figure 3: Derivation of Transmission Tariff Component of Distribution System Flow Chart



Each step in this process to derive transmission component of the distribution system reference tariffs is described in more detail as follows. The first two steps of determining the revenue entitlement and prices for transmission connected users have been covered earlier in this section.

6.3.2 Calculate the Forecast Revenue to be recovered from Distribution-Connected Users

It is assumed at this stage of the process that the forecast transmission revenue entitlement has been determined and transmission reference tariffs set. By applying the reference tariffs to the forecast transmission-connected user data, the revenue to be recovered from transmission entry and exit points can be forecast. The residual is the revenue that must be recovered from connection points on the distribution system.

6.3.3 Calculate Transmission Nodal Prices in terms of $ per kVA

To calculate the transmission prices in terms of dollars per kVA the zone substation power factors must be determined. The power factors are measured at the low voltage bus of the zone substations at system peak. To create a single nodal price the transmission use of system, common service and connection prices are added together for each zone substation. Multiplying that price by the power factor then provides the price in terms of dollars/kVA.

There is an additional factor taken into account at this stage. The Urban and CBD prices are set to be uniform for distribution-connected users. To achieve this, a weighted average transmission nodal price and a weighted average power factor are used.

This step is taken for a number of reasons. It does not make sense for users across the Perth metropolitan area to see a range of prices depending on location. For example users can be connected to one zone substation for a period of time and then transferred to a different zone substation for operational reasons. Individual zone substation nodal prices would result in such a user seeing a price change although they had not changed anything from their perspective. From an administrative perspective it would be very difficult to manage such a situation. Price changes would also need to be managed within any side constraints imposed on price movements.

Another reason for this approach is that nodal prices are designed to give users an economic signal in terms of location. However, in an urban environment it is difficult for users to respond to any economic signal because land zoning and availability will normally be the determining factor in location rather than cost of supply.

This process produces a set of zone substation prices that are individual for Rural, Mixed and Mining substations and uniform for the CBD and Urban substations. These transmission nodal prices apply to connection points on the distribution system with demands equal to or greater than 7,000 kVA. This principle is established because the cost that a 7,000 kVA user imposes on the transmission network will be the same whether connected to the distribution or transmission networks.

For users with CMD below 7,000 kVA the factor of load diversity becomes more relevant. In addition, the price must be structured to fit into the bundled tariff structure for all CMD users with demands greater than 1,000 kVA.

6.3.4 Determine Average Transmission Price at 1,000 kVA

At this stage we have the transmission nodal prices at 7,000 kVA. We also have established that the transmission price in terms of $/kVA at 1,000 kVA will be uniform for all users and will be the same from 0 to 1,000 kVA. The next task is to establish that uniform price.

Transmission costs are allocated to all users on the basis of anytime peak kVA demand. The transmission price is simply the revenue to be recovered from users with demands below 1,000 kVA divided by the sum of the anytime maximum demands of all those users.

The anytime maximum demands are not metered for the vast majority of users with demands below 1,000 kVA. The energy consumption is metered and the anytime maximum demands are estimated by applying load factors based on Industry Codes. The industry codes and associated load factors were developed using sample data for actual representative user types.

At this stage the size of the revenue pool is not established. The revenue pool will be the amount defined by the following formula:

$$RP_{Below\ 1,000} = RP_{Total} - RP_{Over\ 7,000} - RP_{1,000\ to\ 7,000}$$

where,

$RP_{Below\ 1,000}$ = revenue to be recovered from users with demands below 1,000 kVA

RP_{Total} = revenue to be recovered from all distribution connected users

$RP_{Over\ 7,000}$ = revenue to be recovered from users with demands greater than 7,000 kVA

$RP_{1,000\ to\ 7,000}$ = revenue to be recovered from users with demands between 1,000 and 7,000 kVA

This equation has unknown elements in several terms at this stage. The revenue to be recovered from users with demands greater than 7,000 kVA is known because it is equal to the forecast demands of those users multiplied by the nodal price for each user.

The next step is to determine the pricing structure for users with demands between 1,000 and 7,000 kVA. To facilitate the bundling of transmission and distribution components in reference tariffs for connection points on the distribution system the transmission price structure must be consistent with the distribution price structure. For these users this means the prices will be in 'rate block' structure and take the form:

$$\text{User Charge}_{1,000\ to\ 7,000} = (\text{Price}_{At\ 1,000} * 1,000\ kVA) + (\text{Price}_{1,000\ to\ 7,000} *(CMD_{User} - 1,000\ kVA))$$

Where:

$\text{User Charge}_{1,000\ to\ 7,000}$ = the use of system charge for a user with CMD between 1,000 and 7,000 kVA

$\text{Price}_{At\ 1,000}$ = the average use of system price for all users with CMD below 1,000 kVA

$\text{Price}_{1,000\ to\ 7,000}$ = the use of system for this user with CMD between 1,000 and 7,000 kVA

CMD_{User} = the contract maximum demand for that user

The $\text{Price}_{1,000\ to\ 7,000}$ will be different for each zone substation but can be calculated by the formula:

$$\text{Price}_{1,000\ to\ 7,000} = [(\text{Price}_{At\ 7,000} * 7,000\ kVA) - (\text{Price}_{At\ 1,000} * 1,000\ kVA)]/6,000\ kVA$$

So there is now a formula to calculate the price for each user with CMD between 1,000 and 7,000 kVA with the unknown being the price at 1,000 kVA. There is a single unknown ($\text{Price}_{At\ 1,000}$) that can be solved in the above equation which can be expanded as below.

Original Equation:

$$RP_{Below\ 1,000} = RP_{Total} - RP_{Over\ 7,000} - RP_{1,000\ to\ 7,000}$$

Expansion of each term:

RP $_{\text{Below 1,000}}$ = ∑ User anytime maximum demands multiplied by Price At 1,000

RP $_{\text{Total}}$ = Total transmission revenue entitlement allocated to distribution-connected users

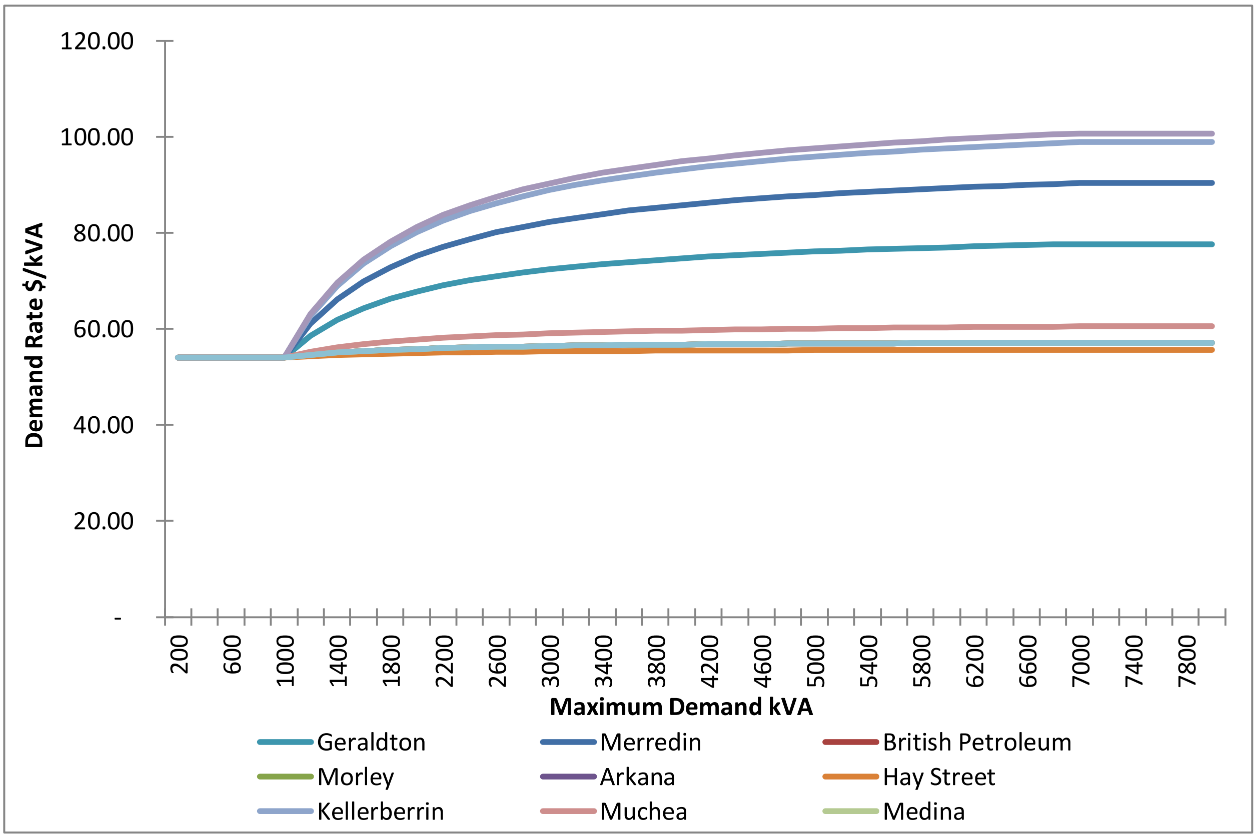
RP $_{\text{Over 7,000}}$ = ∑ Individual demands for users greater than 7,000 kVA anytime maximum demands multiplied by the nodal price at the zone substation to which the user is connected

RP $_{\text{1,000 to 7,000}}$ = ∑ User charges for all users with CMDs between 1,000 and 7,000 kVA

At this stage of the process the average price at and below 1,000 kVA, the nodal price for each zone substation for demands between 1,000 and 7,000 kVA and the nodal price for demands greater than 1,000 kVA are known. This has set the transmission tariffs for CMD users.

The rate blocks were developed using the principle of a straight-line transition from the charge at 1,000 kVA to the charge at 7,000 kVA. When converted back to prices the actual prices at any demand can be mapped and in fact the transition from a flat price below 1,000 kVA to a flat price above 7,000 kVA is a 1/x curve. The following graph illustrates the price outcomes for the above process. A number of substations have been chosen to represent the range of prices across urban and rural substations.

Figure 4: Rate Blocks Example



6.3.5 Calculate Transmission Revenue to be recovered from users with demands below 1,000 kVA

This has been determined in the previous section in that the revenue is the average price multiplied by the sum of the anytime maximum demands of all users with demands less than 1,000 kVA.

6.3.6 Calculate Transmission Prices for all other Customer Groups

The first step in this process is to allocate the total revenue entitlement for all users with demands below 1,000 kVA to the customer groups within this category. The customer groups are restated for reference.

- General Business Large (300 to < 1,000 kVA maximum demand)
- General Business Medium (100 to < 300 kVA maximum)
- General Business Small (15 to < 100 kVA maximum demand)
- Small Business (<15 kVA maximum demand)
- Residential
- Streetlights
- Unmetered Supplies

The result of this process is an amount of revenue that must be recovered within each customer group. At this stage the customer group users are mapped to reference tariff groups together with their associated revenues.

In the case of Transmission reference tariff components the cost pools are allocated on the basis of demand. The tariffs now being considered do not have metered values for demand and on that basis; energy is used as a proxy for demand. The revenue is recovered entirely through the variable component of the tariffs, which in each of these tariffs is the energy rate. Thus the tariff components are in terms of cents per kWh.

In the case of unmetered supplies, streetlights, energy small and energy large tariffs the price is calculated by the formula:

$$\text{Price}_{\text{Tariff}} = \text{Forecast Revenue Entitlement for Tariff} / \text{Total Forecast Energy for Tariff}$$

In the case of the time of use energy tariffs the transmission revenue allocated to those tariffs is recovered through both the on-peak and off-peak energy amounts. It is essentially the on-peak demand and therefore on-peak energy that drives the cost of the transmission network. However off-peak energy must also be served and a proportion of the revenue is recovered through the off-peak energy.

Approximately 30% of the forecast revenue entitlement is recovered through the off-peak energy and 70% through the on-peak energy. This ratio is chosen to achieve three outcomes:

- It recovers most of the cost from on-peak usage which is the main driver of transmission costs;
- It allows for a portion of the costs to be recovered from off-peak energy usage to provide for equity between users with different load patterns; and
- It provides an economic signal to encourage off-peak energy usage that has the benefit of reducing network costs resulting in lower reference tariffs for all users.

6.3.7 Transmission Components of Distribution Reference Tariffs Forecast Revenue

The following table details the forecast transmission reference service revenue, by tariff, which will be collected from distribution connection points.

Table 6.2: Transmission Reference Service Revenue Recovered from Distribution Connection Points for 2018/19 ($M Nominal, annualised values)

Reference Tariff	kWh	Number Customers	Forecast Transmission Revenue Recovered
RT1 - Anytime Energy (Residential)	4,234,000,000	803,987	71.1
RT2 - Anytime Energy (Business)	1,051,000,000	73,608	20.9
RT3 - Time of Use Energy (Residential)	60,000,000	7,993	1.0
RT4 - Time of Use Energy (Business)	965,000,000	9,760	18.9
RT5 - High Voltage Metered Demand	672,000,000	288	8.1
RT6 - Low Voltage Metered Demand	2,029,000,000	3,901	32.8
RT7 - High Voltage Contract Maximum Demand	3,089,000,000	285	55.6
RT8 - Low Voltage Contract Maximum Demand	196,000,000	57	4.0
RT9 – Streetlighting	134,000,000	272,664	1.4
RT10 - Unmetered Supplies	37,000,000	16,198	0.3
RT11 - Distribution Entry	-	20	1.3
RT13 – Anytime Energy (Residential) Bi-directional	1,012,000,000	204,050	17.0
RT14 – Anytime Energy (Business) Bi-directional	59,000,000	1,363	1.2
RT15 – Time of Use (Residential) Bi-directional	53,000,000	9,631	0.8
RT16 – Time of Use (Business) Bi-directional	102,000,000	548	2.0
RT17 - Time of Use Energy (Residential)	0	0	-
RT18 - Time of Use Energy (Business)	0	0	-
TOTAL - Reference Service	**13,693,000,000**	**1,404,415**	**323.0**
TOTAL – Non-Reference Service	-	-	3.5
TOTAL			**326.5**

6.4 Annual Price Review

As described in the *access arrangement*, revenue cap service revenue is reviewed annually and adjusted if necessary for under or over recovery. Together with changes to user CMDs and DSOCs (including zone substation maximum demands) it is consequently necessary to adjust prices annually also.

6.5 Compliance with sections 7.3 (b) and 7.6 of the *Code*

Section 7.3 (b) of the *Code* requires that reference tariffs are set between the incremental and stand-alone costs of service provision. For transmission reference tariffs, Western Power asserts that the pricing method described above, in particular the application of the T-price approach to tariff setting, ensures that tariffs remain between these two bounds.

As a result, section 7.6 of the *Code* which requires that variable components of tariffs recover the incremental costs of service provision, is also deemed to be satisfied.

For distribution reference tariffs, compliance is demonstrated in section 7.3 of this document.

7. Derivation of Distribution System Tariff Components

This section describes the methodology used to calculate distribution reference tariff components.

The cost allocation process reflects the costs of supply for a customer group reasonably accurately. The process for determining prices for that customer group, while ideally similar in principle, is somewhat different in that it must take into account other factors such as equity, simplicity and efficiency (e.g. existing metering type).

Prices are determined with pre loss-adjusted ATMDs.

The *Code* requires uniform reference tariffs for all users with annual energy demand below 1 MVA, which equates to approximately all but 500 connected to the Western Power Network. Users with energy demand below 1 MVA will exhibit the full range of energy consumption patterns. It is therefore clear that any tariff structure will not be totally cost reflective. However, the assumptions that are made in allocating users to particular load groups and in deriving the cost of supply to those customer groups, and the consequent prices, are all considered reasonable. Through the process described in this paper the tariff settings are derived through a rigorous process taking into account the information available and the requirements of the *Code*.

The distribution reference tariff components include the costs associated with the TEC. Section 7.12 of the *Code* sets out the requirement for Western Power to recover TEC through distribution reference tariffs for exit services (Western Power has extended this to include bi-directional services to be consistent with the Code Objective). Section 7.6 details the amounts associated with TEC that are embedded within the distribution reference tariff components.

7.1 Price Setting

This section details the methodology used to derive the tariff components from the cost pools, customer groups and locational zones.

7.1.1 Tariff Components

Distribution reference tariffs have been developed to enable users with different loads and usage patterns to choose the most appropriate form for them. The tariffs have fixed and variable components and are generally compatible with existing forms of user metering.

The components of each reference tariff are shown in the following table.

Table 7.1: Distribution Reference Tariff Components

TARIFF		TARIFF COMPONENTS								
	Fixed Component	Energy Only	On Peak Energy	Shoulder Energy	Off Peak Energy	Metered Demand	Annual Metered Demand	Off Peak Discount Factor (%)	CMD/DSOC	Demand/ Length for ATMD > 1,000 kVA	Fixed Metering Component
RT1 – Anytime Energy (Residential)	✓	✓									✓
RT2 – Anytime Energy (Business)	✓	✓									✓
RT3 - Time of Use Energy (Residential)	✓		✓		✓						✓
RT4 - Time of Use Energy (Business)	✓		✓		✓						✓
RT5 - HV Metered Demand	✓					✓	✓	✓		✓	✓
RT6 - LV Metered Demand	✓					✓	✓	✓		✓	✓
RT7 - HV CMD	✓								✓	✓	✓
RT8 - LV CMD	✓								✓	✓	✓
RT9 - Streetlighting	✓	✓									
RT10 – Unmetered Supplies	✓	✓									
RT11 - Distribution Entry									✓	✓	✓
RT13 – Anytime Energy (Residential) Bi-directional	✓	✓									✓
RT14 – Anytime Energy (Business) Bi-directional	✓	✓									✓
RT15 – Time of Use (Residential) Bi-directional	✓		✓		✓						✓
RT16 – Time of Use (Business) Bi-directional	✓		✓		✓						✓
RT17 - Time of Use Energy (Residential)	✓		✓	✓	✓						✓
RT18 - Time of Use Energy (Business)	✓		✓	✓	✓						✓

7.1.2 The tariff comprises a fixed component ($/annum) and a variable component (cents/kWh)

This is the simplest and most appropriate charging methodology for large numbers of small users with existing energy only metering.

The fixed and variable components are set to best recover the costs associated with the smaller customer groups. The tariff components for residential and business are different, reflecting the different costs of supply.

7.1.3 RT3 and RT4 - Time of Use Energy Tariff (Residential or Business)

The tariff comprises a fixed component ($/annum) and variable on- and off-peak energy components (cents/kWh).

The tariff components for residential and business are different, reflecting the different costs of supply.

The fixed component of the residential time of use tariff is set to be the same as the fixed component of the residential energy only tariff.

Analysis of system load profiles by other utilities shows that typically 70% and 30% of network costs are associated with on- and off-peak load respectively. The on- and off-peak energy components of the tariffs are set to recover these approximate proportions of the variable cost pools for the respective customer groups.

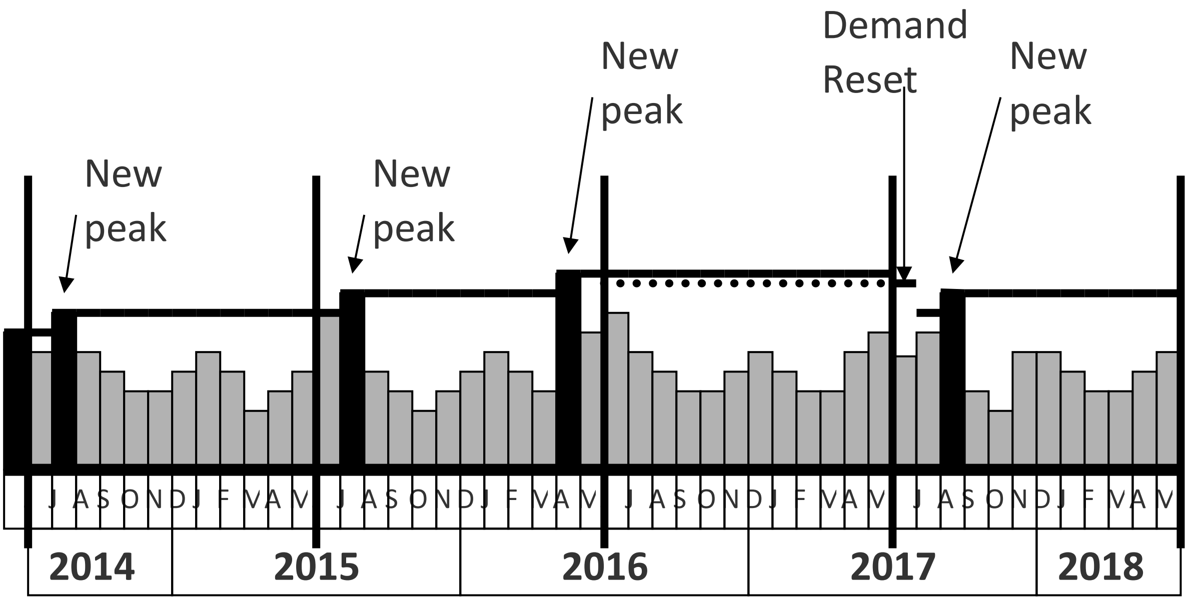
7.1.4 RT5 and RT6 - Metered Demand Tariff (HV and LV)

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.

Figure 5: 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.

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 and is defined within the Price List.

7.1.5 RT7 and RT8 - Contract Maximum Demand Tariff (HV and LV)

The HV component of the CMD tariff is set to reflect a price that results in a user charge that is greater than the user incremental cost of supply but less than the stand-alone cost of supply. To achieve this outcome the two costs of service are modelled for each of the HV and LV CMD users.

Customers on transition tariffs are modelled, for pricing setting purposes, as contract maximum demand tariff customers.

The price structure is based on two particular components. There is a component that is directly linked to the nominated maximum demand which is in terms of $/kVA. The second component is based on a combination of the maximum demand and the length of HV feeder from the zone substation to the user's connection point. This price component is expressed in terms of $/kVA.km. Both of these tariff components are set to be uniform at 1,000 kVA and to be fully cost reflective at 7,000 kVA. This structure is consistent with the transmission CMD tariff for distribution connected customers.

The demand-length component of the tariff cannot be used in isolation because it distorts the charge for users either very close to the zone substation, where the cost could be virtually zero, or at a long distance from the substation, where the charge could be unreasonably high. The demand-based components of the tariff ameliorates this distortion as it recognises the cost of supply of a user does not only relate to the distance from the zone substation but also relates to the demand the user places on the network.

The effect of the pricing structure is, for a fixed demand, the charge to a user increases as distance to the zone substation increases. This is effectively providing a fixed and variable component to the price for identical users depending on their distance from a zone substation. In a similar manner users at the same distance from a zone substation will pay more as their demand increases.

An additional feature of this price structure is that the price is not linear in relation to the demand.

For the demand-based component, the price at 1,000 kVA is uniform for each of the locational zones and is reflective of the average HV cost of the network per KVA demand. However, as the demand increases, the price declines recognising that the cost of supply declines on a per unit basis, as the demand increases.

The demand-length component is set to zero at 1,000 kVA. This is consistent with the requirement that all tariffs are uniform below 1,000 kVA demand. The price above 7,000 kVA is uniform and the price varies continuously between 1,000 and 7,000 kVA.

In setting the CMD tariffs both components are adjusted so that for each of the users with demands greater than 1,000 kVA, their charge will fall between the incremental and stand-alone cost. The process to derive the settings is described as follows.

Demand Component of the CMD Tariff

The price at 7,000 kVA is individually set for each zone. The price is adjusted to provide a best fit so that users will see a charge that is between the incremental and stand-alone cost. This is done in combination with the demand-length component setting. However it is clear that the price at 7,000 kVA should reflect the actual costs of the networks that supply these users. As such the cost for the CBD zone will be the highest, the Urban zone the next highest and so on so that the rural zone is the cheapest.

The distribution nodal prices at 7,000 kVA have been established. It has also been established the distribution price in terms of $/kVA at 1,000 kVA will be uniform for all users and will be the same from 0 to 1,000 kVA. The next step is to establish that uniform price. At 1,000 kVA the demand-length price is zero so the demand price should reflect the average network price for all users in terms of $/kVA.

Distribution costs are allocated to all users on the basis of anytime peak kVA demand adjusted for losses. The distribution price is simply the revenue to be recovered from users with demands below 1,000 kVA divided by the sum of the anytime maximum demands of all those users.

The anytime maximum demands are not metered for the vast majority of users with demands below 1,000 kVA. The energy consumption is metered and the anytime maximum demands are estimated by applying load factors based on 'industry codes'. The industry codes and associated load factors were developed using sample data for actual representative user types.

At this stage the size of the revenue pool for users with demands below 1,000 kVA is not established. The revenue pool will be the amount defined by the following formula:

$$RP_{\text{Below } 1,000} = RP_{\text{Total}} - RP_{\text{Over } 7,000} - RP_{1,000 \text{ to } 7,000}$$

where:

$RP_{\text{Below }1,000}$ = revenue to be recovered from users with demands below 1,000 kVA

RP_{Total} = revenue to be recovered from all distribution users

$RP_{\text{Over }7,000}$ = revenue to be recovered from users with demands greater than 7,000 kVA

$RP_{1,000\text{ to }7,000}$ = revenue to be recovered from users with demands between 1,000 and 7,000 kVA

This equation has unknown elements in each of the terms at this stage. The revenue pools will only be determined when the CMD tariff settings are established and the prices can be applied to the forecast user data for users with demands greater than 1,000 kVA. The price at 7,000 kVA is set by graphically plotting the charge outcomes for each of the users with demands above 7,000 kVA, in the locational zones, and setting a price that puts the charge outcomes between the incremental and stand-alone cost of supply. Graphs demonstrating this are included in section 7.2.

To facilitate the solving of the remaining terms of this equation the pricing settings for users with demands between 1,000 and 7,000 kVA must be determined. The tariffs are defined in terms of 'rate block' structure and, for the demand component of the tariff, take the form:

$$\text{User Demand Charge}_{1,000\text{ to }7,000} = (\text{Price}_{\text{At }1,000} * 1,000\text{ kVA}) + (\text{Price}_{1,000\text{ to }7,000} *(\text{CMD}_{\text{User}} - 1,000\text{ kVA}))$$

where:

$\text{User Demand Charge}_{1,000\text{ to }7,000}$ = the demand charge for a user with CMD between 1,000 and 7,000 kVA

$\text{Price}_{\text{At }1,000}$ = the average demand price for all users with CMD below 1,000 kVA

$\text{Price}_{1,000\text{ to }7,000}$ = the incremental demand price for this user with CMD between 1,000 and 7,000 kVA

CMD_{User} = the contract maximum demand for that user

The $\text{Price}_{1,000\text{ to }7,000}$ will be different for each locational zone but can be calculated by the formula:

$$\text{Price}_{1,000\text{ to }7,000} = [(\text{Price}_{\text{At }7,000} * 7,000\text{ kVA}) - (\text{Price}_{\text{At }1,000} * 1,000\text{ kVA})]/6,000\text{ kVA}$$

There is now a formula to calculate the price for each user with CMD between 1,000 and 7,000 kVA with the unknown being the price at 1,000 kVA. The price at 7,000 kVA has been previously set.

There is now a single unknown (Price At 1,000) that can be solved in the above equation which now must be expanded as below.

Original Equation:

$$RP_{\text{Below }1,000} = RP_{\text{Total}} - RP_{\text{Over }7,000} - RP_{1,000\text{ to }7,000}$$

Expansion of each term:

$RP_{\text{Below }1,000}$ = ∑ User anytime maximum demands multiplied by Price At 1,000

RP_{Total} = Total HV network revenue entitlement

$RP_{\text{Over } 7,000}$ = ∑ Individual demands for users greater than 7,000 kVA anytime maximum demands multiplied by the zonal price at the zone substation to which the user is connected

$RP_{1,000 \text{ to } 7,000}$ = ∑ User charges for all users with CMDs between 1,000 and 7,000 kVA

At this stage of the process the average price at and below 1,000 kVA, the demand price formula for each locational zone for demands between 1,000 and 7,000 kVA and the zonal price for demands greater than 7,000 kVA is known. This has set the demand component of the CMD tariffs.

Demand-Length Component of the CMD Tariff

The demand-length component of the tariff is set at zero at 1,000 kVA. It is also uniform at and above 7,000 kVA. The tariff is designed to be expressed in 'rate block' format so that the price is in terms of an incremental price above 1,000 kVA and up to 7,000 kVA and a uniform price above 7,000 kVA.

The price between 1,000 and 7,000 kVA is expressed as:

$$Price_{1,000 \text{ to } 7,000} = [(Price_{\text{At } 7,000} * 7,000 \text{ kVA}) - (Price_{\text{At } 1,000} * 1,000 \text{ kVA})]/6,000 \text{ kVA}$$

The price settings are established in the same process as setting the demand settings in that the incremental and stand-alone costs are graphically plotted for every CMD user within each locational zone and the price settings are adjusted so the user charges fit between the limits. Graphs demonstrating this are included in section 7.2.

At this stage, the price settings are established for both the demand and demand-length price components of the CMD tariffs. The forecast HV network revenue for the HV and LV CMD users can be calculated by applying the prices to the forecast user data and summing the charges for all users.

The prices for both the demand and demand-length components of the prices are illustrated in Figure 11.

7.1.6 Metering Prices

The prices for distribution metering are split into two charges:

- For accumulation or AMI
- For interval meters (that are not AMI)

The costs involved in reading interval meters are higher than for accumulation meters and are priced accordingly. The largest contributor to this cost difference is the reading costs themselves; manual reads involve higher labour costs (as the data is time consuming to extract), and for remotely read (non-AMI) meters the higher costs are attributable to the costs of the monthly data transmission via sim cards.

7.1.7 Administration costs

An administration charge is published separately in conjunction with the CMD tariff, but is incorporated in the variable component of all the other tariffs.

The setting of the components in the metered demand tariff ensures compatibility with the administration price for the CMD tariff.

7.1.8 RT9 – Streetlighting Tariff

Separate network Use of System and Asset prices are designed to best recover the costs of providing streetlight services.

The use of system price comprises a fixed and variable charge similar to other low voltage tariffs, based on the expected daily cycle of energy usage.

The asset charge varies with the size and type of luminaire and is based on the annualised cost of capital and maintenance associated with each.

7.1.9 RT10 - Unmetered Supplies

The unmetered supplies tariff comprises a fixed and variable charge similar to other low voltage tariffs, designed to best recover the costs of providing these services based on the expected daily cycle of energy usage.

7.1.10 RT13 to 16 - Bi-directional Tariffs

The tariff components for these tariffs are identical to tariffs RT1 to 4, as applicable.

7.2 Demonstration of Derivation of Distribution Components of Distribution Reference Tariffs

7.2.1 CMD Demand Price Graphs

The following graphs illustrate the proposed prices for the CMD tariffs are between incremental cost and stand-alone cost for the majority of customers. However, no pricing structure can be guaranteed to price between them in every individual case. The prices have been set to achieve a balance between all customers, while still meeting the requirements of section 7.3(b) of the *Code*. Compliance with section 7.3 of the *Code* is demonstrated in section 7.3.

Figure 6: Urban Zone

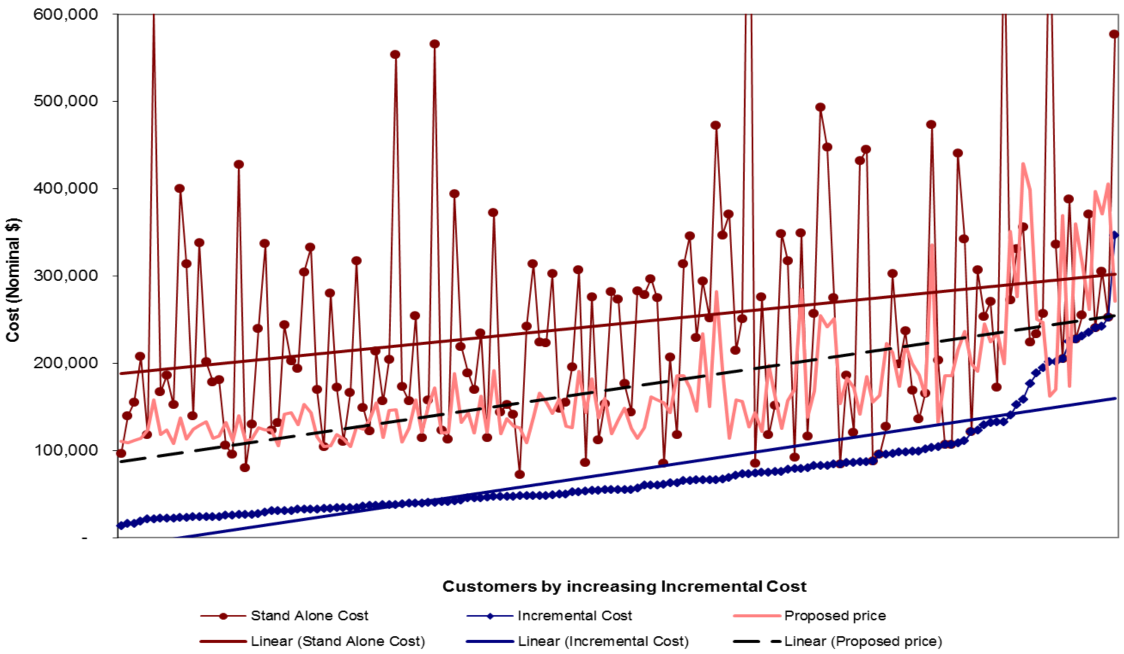


Figure 7: CBD Zone

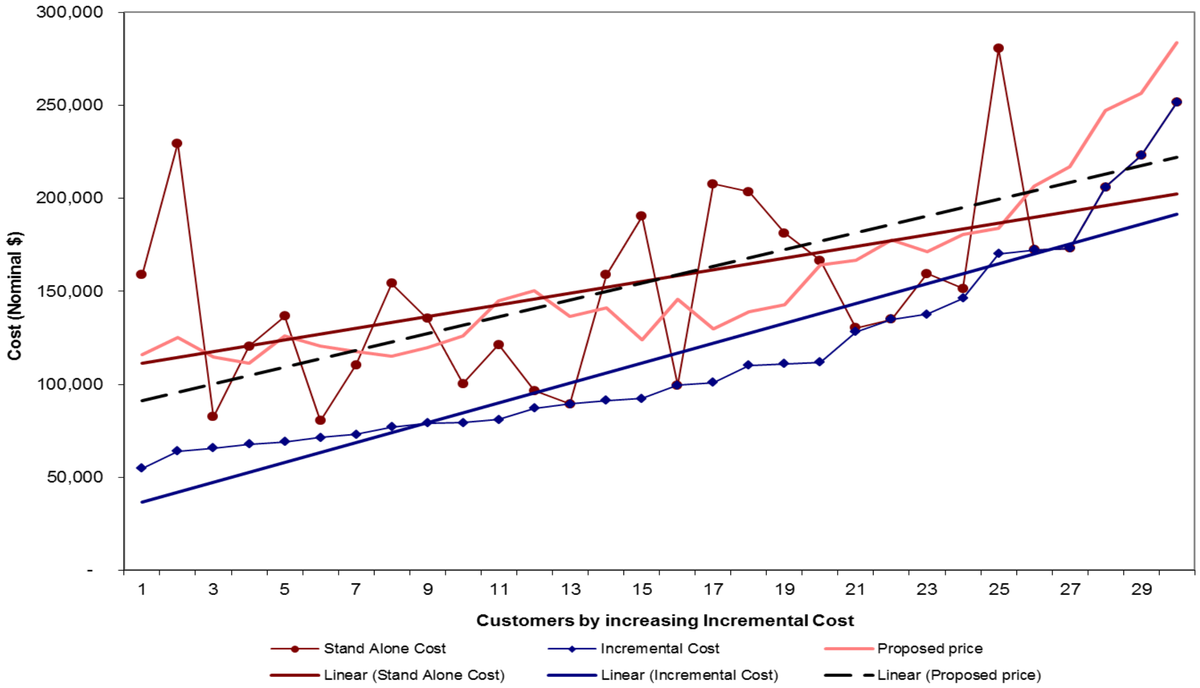


Figure 8: Mining Zone

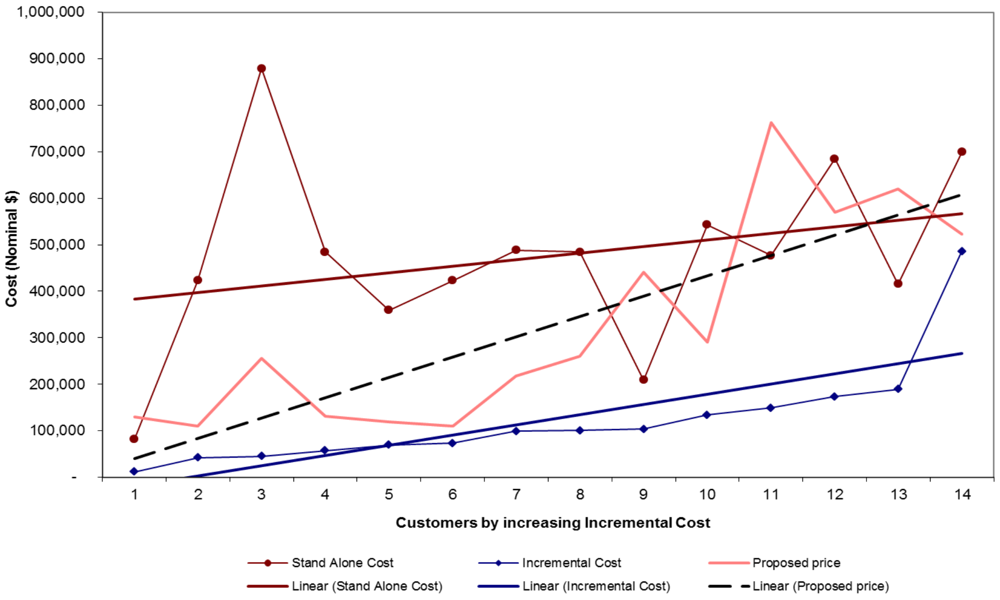


Figure 9: Mixed Zone

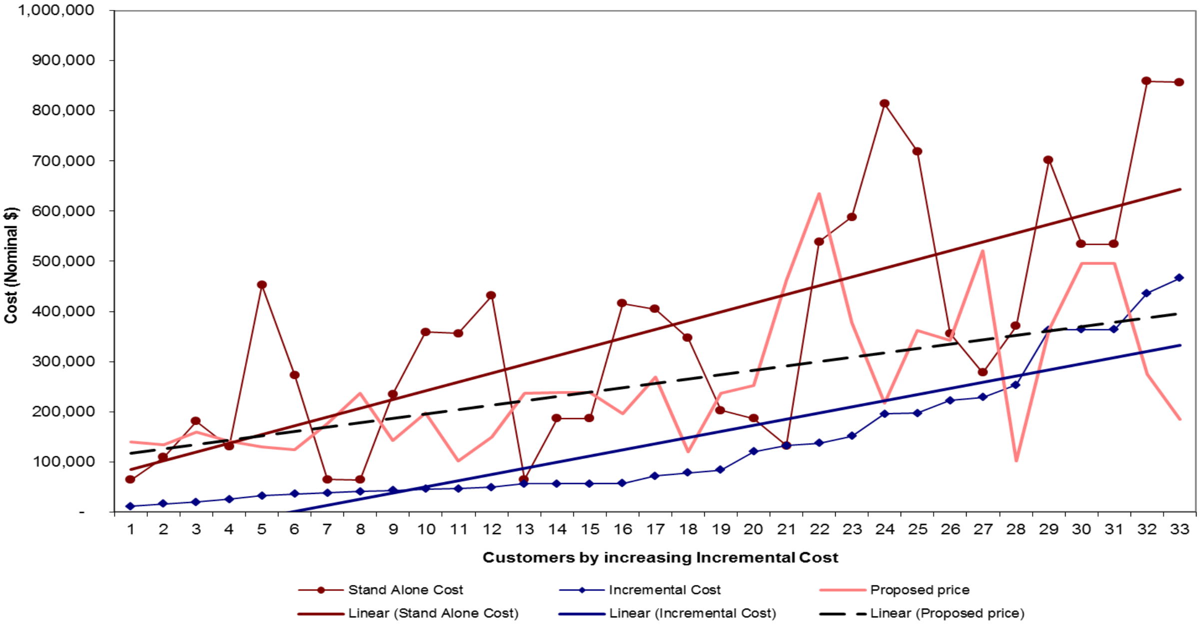
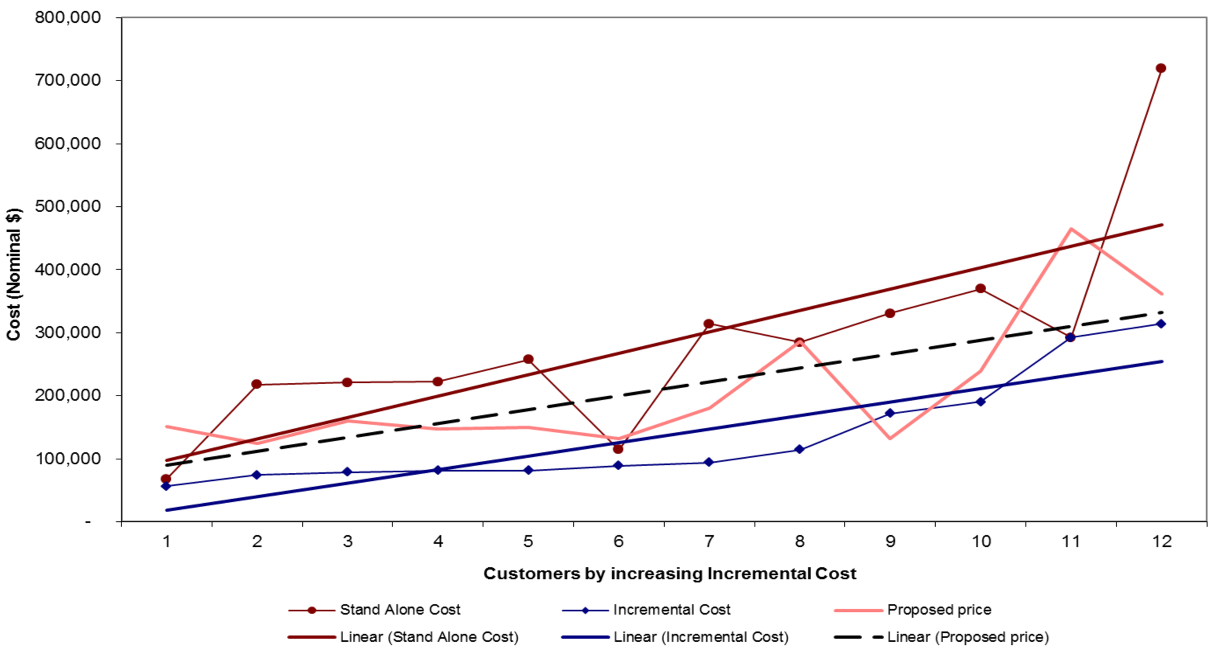
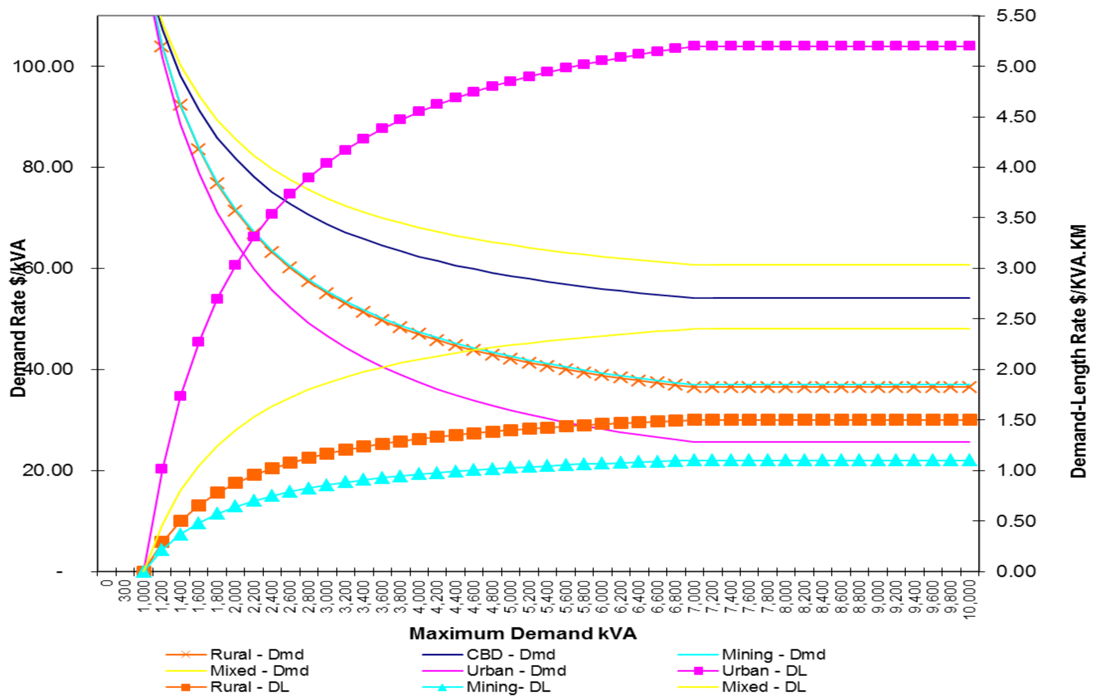


Figure 10: Rural Zone



7.2.2 Demand/Length Graph

Figure 11: Demand Length Rates and CMD Rates by Zone



7.2.3 Forecast Tariff Revenue

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

Table 7.2: Distribution Reference Service Revenue Recovered from Distribution Connection Points for 2018/19 ($M Nominal, annualised values)

Reference Tariff	kWh	Number Customers	Forecast Distribution Revenue Recovered
RT1 - Anytime Energy (Residential)	4,234,000,000	803,987	572.7
RT2 - Anytime Energy (Business)	1,051,000,000	73,608	151.0
RT3 - Time of Use Energy (Residential)	60,000,000	7,993	6.6
RT4 - Time of Use Energy (Business)	965,000,000	9,760	90.3
RT5 - High Voltage Metered Demand	672,000,000	288	26.3
RT6 - Low Voltage Metered Demand	2,029,000,000	3,901	125.0
RT7 - High Voltage Contract Maximum Demand	3,089,000,000	285	55.1
RT8 - Low Voltage Contract Maximum Demand	196,000,000	57	9.7
RT9 – Streetlighting	134,000,000	272,664	41.2
RT10 - Unmetered Supplies	37,000,000	16,198	4.8
RT11 - Distribution Entry	-	20	2.2
RT13 – Anytime Energy (Residential) Bi-directional	1,012,000,000	204,050	141.0
RT14 – Anytime Energy (Business) Bi-directional	59,000,000	1,363	6.5
RT15 – Time of Use (Residential) Bi-directional	53,000,000	9,631	6.5
RT16 – Time of Use (Business) Bi-directional	102,000,000	548	9.0
RT17 - Time of Use Energy (Residential)	0	0	-
RT18 - Time of Use Energy (Business)	0	0	-
TOTAL – Reference Services	**13,693,000,000**	**1,404,415**	**1,248.0**
TOTAL – Non-Reference Services			0.7
TOTAL			**1,248.7**

7.3 Demonstration that Distribution Reference Tariffs are between incremental and stand-alone cost of service provision

In accordance with section 7.3(b) of the *Code*, reference tariffs are set to at least recover the incremental cost, but to be less than the stand-alone cost of service provision. The following table demonstrates the outcomes for 2018/19.

Table 7.3: Demonstration Reference Tariffs are between incremental and stand-alone cost of service provision for 2018/19 ($M Nominal, annualised revenue)

Reference Service	Reference Tariff	Incremental Cost of Service	Stand-alone Cost of Service Provision	Forecast Revenue Recovered from Reference Tariff
A1	RT1	204.8	618.1	565.6
A2	RT2	49.8	368.0	152.1
A3	RT3	2.9	109.4	6.6
A4	RT4	42.2	299.1	91.9
A5	RT5	19.0	516.5	23.8
A6	RT6	44.8	452.1	116.6
A7	RT7	21.8	78.2	105.8
A8	RT8	3.8	14.6	12.2
A9	RT9	19.6	279.4	41.6
A10	RT10	0.8	308.4	4.8
C1	RT13	54.4	166.2	139.3
C2	RT14	3.5	33.6	6.6
C3	RT15	2.5	119.4	6.6
C4	RT16	6.1	24.1	9.2
D1	RT17	0	0	-
D2	RT18	0	0	-

7.3.1 Method to calculate incremental and stand-alone cost of service provision

Western Power has updated the method used to derive incremental cost in Table 7.3. The definition of incremental cost in the *Code* requires Western Power to consider only that portion of approved total costs that would be avoided if the customer group was not served. As most elements of total costs are fixed and relate to the Regulated Asset Base, these costs have been excluded. In any one year of an *access arrangement*, the only cost savings that would result from not serving a customer group would be the operating costs allocated to that customer group. As such, the method to determine incremental costs considers only operating costs.

Once this adjustment to total costs for incremental costs has been made, the values in Table 7.3 are derived during the cost of supply modelling process. For the stand-alone costs, each service is allocated a combination of fixed and variable cost pools calculated as per this document. Table 7.4 demonstrates the allocations made.

Table 7.4 – Cost pools used to determine stand-alone cost

Stand-alone cost
Fixed and variable transmission costs allocated to the service
Metering costs allocated to the service
Variable distribution costs allocated to the service
The relevant fixed distribution costs allocated to the service

7.4 Demonstration that incremental costs are recovered through variable components

Section 7.6 of the *Code* states that the incremental cost of service provision should be recovered by the variable components of tariffs. Western Power has had regard to this requirement in setting tariffs. The following table shows that the variable components for 2018/19 tariffs exceeds the incremental cost calculated in section 7.3 for all tariffs.

Table 7.5: Demonstration that variable costs exceed incremental costs ($M Nominal)

Reference Service	Reference Tariff	Incremental Cost of Service	Variable tariff components
A1	RT1	204.8	360.5
A2	RT2	49.8	119.5
A3	RT3	2.9	4.7
A4	RT4	42.2	95.5
A5	RT5	19.0	34.1
A6	RT6	44.8	140.7
A7	RT7	21.8	66.9
A8	RT8	3.8	5.6
A9	RT9	19.6	34.6
A10	RT10	0.8	1.7
C1	RT13	54.4	86.2
C2	RT14	3.5	6.7
C3	RT15	2.5	3.9
C4	RT16	6.1	10.3
D1	RT17		
D2	RT18		

7.5 Annual Price Review

At the end of each year, the actual distribution reference service revenue entitlement is reconciled against the actual distribution reference service revenue recovered for that year, and an equivalent correction factor is applied to the forecast reference service revenue for the subsequent year. Tariffs are then adjusted to recover the corrected revenue for the following year and the new prices published.

Distribution prices can be volatile due to matters beyond the control of any one user. In order to minimise this volatility and reduce the commercial uncertainty for users, revenues are subject to an annual 'side constraint' (effectively a limit on annual reference tariff revenue changes) as detailed in the *access arrangement*. This side constraint will, by extension, have a controlling effect on price movements.

7.6 TEC in the Distribution Components of Distribution Reference Tariffs

This section details the amounts associated with TEC that are embedded within the distribution 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.

7.6.1 TEC Forecast Revenue

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

Table 7.6 - TEC Recovered from Distribution Connection Points for 2018/19 ($M Nominal, annualised values)

Reference Tariff	kWh	Number Customers	Forecast TEC Recovered
RT1 - Anytime Energy (Residential)	4,234,000,000	803,987	78.2
RT2 - Anytime Energy (Business)	1,051,000,000	73,608	19.9
RT3 - Time of Use Energy (Residential)	60,000,000	7,993	0.9
RT4 - Time of Use Energy (Business)	965,000,000	9,760	17.3
RT5 - High Voltage Metered Demand	672,000,000	288	10.6
RT6 - Low Voltage Metered Demand	2,029,000,000	3,901	41.2
RT7 - High Voltage Contract Maximum Demand	3,089,000,000	285	4.9

Reference Tariff	kWh	Number Customers	Forecast TEC Recovered
RT8 - Low Voltage Contract Maximum Demand	196,000,000	57	1.4
RT9 – Streetlighting	134,000,000	272,664	1.0
RT10 - Unmetered Supplies	37,000,000	16,198	0.3
RT11 - Distribution Entry	-	20	-
RT13 – Anytime Energy (Residential) Bi-directional	1,012,000,000	204,050	18.7
RT14 – Anytime Energy (Business) Bi-directional	59,000,000	1,363	1.1
RT15 – Time of Use (Residential) Bi-directional	53,000,000	9,631	0.8
RT16 – Time of Use (Business) Bi-directional	102,000,000	548	1.9
RT17 - Time of Use Energy (Residential)	0	0	-
RT18 - Time of Use Energy (Business)	0	0	-
TOTAL			**198.0**

7.6.2 TEC Tariff Components – Use of System

The following table details the amounts associated with TEC that are embedded within the distribution reference tariff use of system components.

Table 7.7: TEC Tariff Components – UOS

		Fixed TEC	Variable TEC		
		c/day	c/kWh	On Peak c/kWh	Off Peak c/kWh
Reference tariff 1 - RT1					
	TEC	-	1.846	-	-
Reference tariff 2 - RT2					
	TEC	-	1.890	-	-
Reference tariff 3 - RT3					
	TEC	-	-	2.692	0.770
Reference tariff 4 - RT4					

	TEC	-	-	2.770	0.792
Reference tariff 9 – RT9					
	TEC	-	0.727	-	-
Reference tariff 10 – RT10					
	TEC	-	0.766	-	-
Reference tariff 13 – RT13					
	TEC	-	1.846	-	-
Reference tariff 14 – RT14					
	TEC	-	1.890	-	-
Reference tariff 15 – RT15					
	TEC	-	-	2.692	0.770
Reference tariff 16 – RT16					
	TEC	-	-	2.770	0.792

7.6.3 TEC Tariff Components – Metered Demand

The following table details the amounts associated with TEC that are embedded within the distribution reference tariff metered demand components.

Table 7.8: TEC Tariff Components – Metered Demand

	RT5 – TEC		RT6 – TEC	
Demand (kVA) (Lower to upper threshold)	**Fixed c/day**	**Demand (in excess of lower threshold) c/kVA/day**	**Fixed c/day**	**Demand (in excess of lower threshold) c/kVA/day**
0 to 300	17.340	20.646	17.340	20.646
300 to 1000	6,210.992	19.916	6,210.992	19.916
1000 to 1500	20,152.467	7.244	20,152.467	7.244

7.6.4 TEC Tariff Components – Demand Prices

The following table details the amounts associated with TEC that are embedded within the distribution reference tariff demand components.

Table 7.9: TEC Tariff Components – Demand Prices

Pricing Zone	RT 7 and RT 8 – TEC		
	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)
CBD	6,311.754	-1.052	0.000
Goldfields Mining	6,311.754	-1.052	0.000
Mixed	6,311.754	-1.052	0.000
Rural	6,311.754	-1.052	0.000
Urban	6,311.754	-1.052	0.000

Note: Users with demand greater than 7,000 kVA do not pay TEC. These users can usually choose between being transmission or distribution connected. TEC does not apply to transmission connected users. Charging TEC to distribution connected users with demand greater than 7,000 kVA would create a perverse incentive for users to transition to being transmission connected due to the additional charge. The variable demand charge between 1,000 and 7,000 kVA is negative so that when added to the fixed demand charge users with demand greater than 7,000 kVA do not pay TEC.

7.6.5 TEC Tariff Components – LV prices

The following table details the amounts associated with TEC that are embedded within the distribution reference tariff RT8.

Table 7.10: TEC Tariff Components – LV prices

	Fixed	Demand (c/day)
LV Prices	0.00	1.996/kVA

8. Price Changes

8.1 Side Constraint Demonstration

The following table demonstrates compliance with the side constraint as detailed in sections 6.5.13 and 6.5.14 of the *access arrangement*. The side constraints are reproduced below. Note for 2018/19, the side constraint represents the movement in annual prices, this is a weighted average of prices during the year. That is, 4 months of existing prices combined with 8 months of new prices.

For distribution tariff revenues:

$$\frac{\sum_{y=1}^{n} p_t^{xy} q_t^{xy}}{\sum_{y=1}^{n} p_{t-1}^{xy} q_t^{xy}} \leq (1+CPI_t)(1-DX_t) + A'_t + 0.02$$

where:

$$A'_t = \frac{DK_t + DAA3_t + \Delta TEC_t}{DR'_t}$$

For transmission tariff revenues:

$$\frac{\sum_{y=1}^{n} p_t^{xy} q_t^{xy}}{\sum_{y=1}^{n} p_{t-1}^{xy} q_t^{xy}} \leq (1+CPI_t)(1-TX_t) + B'_t + 0.02$$

where:

$$B'_t = \frac{TK_t + TAA3_t}{TR'_t}$$

The following values have been used to calculate the right hand side of each side constraint in 2018/19:

Table 8.1: 2018/19 Side Constraint Components

Variable	Value	Variable	Value
CPI_t	1.84%	$DAA3_t$	0
DX_t	3.29%	$TAA3_t$	0
TX_t	-6.95%	ΔTEC_t	$31M
TK_t	$0m	TR'_t	$314.0M
DK_t	$0m	DR'_t	$1,032.6M
A'_t	3%	B'_t	0%

Side constraint values:

Table 8.2: Side constraint values

Distribution	Constraint	Transmission	Constraint
$(1+CPI_t)(1-DX_t)+A'_t+0.02$	3.5%	$(1+CPI_t)(1-TX_t)+B'_t+0.02$	10.9%

Table 8.3: Demonstrates compliance with these constraints on all tariffs

Tariff	Change in weighted average prices		Constraint compliance	
RT1	2%	8%	✓	✓
RT2	3%	8%	✓	✓
RT3	-1%	8%	✓	✓
RT4	3%	8%	✓	✓
RT5	2%	8%	✓	✓
RT6	3%	8%	✓	✓
RT7	0%	8%	✓	✓
RT8	2%	8%	✓	✓
RT9	0%	8%	✓	✓
RT10	3%	8%	✓	✓
RT11	0%	8%	✓	✓
RT13	2%	8%	✓	✓
RT14	0%	8%	✓	✓
RT15	0%	8%	✓	✓
RT16	2%	8%	✓	✓
RT17	N/A	N/A	N/A	N/A
RT18	N/A	N/A	N/A	N/A
TRT1	N/A	7%	N/A	✓
TRT2	N/A	6%	N/A	✓

8.2 Individual component changes

The following tables detail the % change in the 2018/19 tariff components when compared to the 2016/17 tariff components (noting that there was no 2017/18 Price List).

8.2.1 Use of System Prices

The % changes in the following table are applicable for reference tariffs: RT1, RT2, RT3, RT4, RT9, RT10, RT13, RT14, RT15 and RT16.

Table 8.4: System Prices RT1, RT2, RT3, RT4, RT9, RT10, RT13, RT14, RT15 and RT16[5]

		Fixed Price	Energy Rates		
		% Change	Anytime % Change	On Peak % Change	Off Peak % Change
Reference tariff 1 - RT1					
	Transmission		12.2%		
	Distribution	7.3%	6.0%		
	Bundled Tariff	7.3%	7.2%		
Reference tariff 2 – RT2					
	Transmission		12.3%		
	Distribution	21.7%	4.4%		
	Bundled Tariff	21.7%	5.7%		
Reference tariff 3 - RT3					
	Transmission			12.3%	12.3%
	Distribution	7.3%		5.1%	6.4%
	Bundled Tariff	7.3%		6.5%	7.5%
Reference tariff 4 - RT4					
	Transmission			12.3%	12.3%
	Distribution	20.9%		4.7%	6.0%
	Bundled Tariff	20.9%		6.1%	7.3%
Reference tariff 9 – RT9					
	Transmission		12.3%		

5 Note for 2018/19, the approach to metering prices has changed and so the comparison is no longer appropriate. The changes will be reported annually from 2019/20 based on the new approach to pricing. In general, metering prices have reduced significantly in AA4.

	Fixed Price	Energy Rates		
	% Change	Anytime % Change	On Peak % Change	Off Peak % Change
Distribution	12.5%	4.4%		
Bundled Tariff	12.5%	6.1%		
Reference tariff 10 – RT10				
Transmission		12.3%		
Distribution	4.1%	4.3%		
Bundled Tariff	4.1%	5.5%		
Reference tariff 13 – RT13				
Transmission		12.2%		
Distribution	7.3%	6.0%		
Bundled Tariff	7.3%	7.2%		
Reference tariff 14 – RT14				
Transmission		12.3%		
Distribution	21.7%	4.4%		
Bundled Tariff	21.7%	5.7%		
Reference tariff 15 – RT15				
Transmission			12.3%	12.3%
Distribution	7.3%		5.1%	6.4%
Bundled Tariff	7.3%		6.5%	7.5%
Reference tariff 16 – RT16				
Transmission			12.3%	12.3%
Distribution	20.9%		4.7%	6.0%
Bundled Tariff	20.9%		6.1%	7.3%

8.2.2 Streetlight Asset Prices

The % changes in the following table are applicable for reference tariff: RT9.

Table 8.5: Streetlight Asset Prices RT9

Light Specification	Annual Charge % Change
42W CFL SE	-4.3%
42W CFL BH	-4.3%
42W CFL KN	-4.3%
70W MH	-4.3%
70W HPS	-4.3%
125W MV	-4.3%
150W MH	-4.3%
150W HPS	-4.3%
250W MH	-4.3%
250W HPS	-4.3%
Standard LED 20W	-
Standard LED 36W	-
Standard LED 53W	-
Standard LED 80W	-
Standard LED 160W	-
Standard LED 170W	-
Decorative BH LED 17W	-
Decorative KN LED 17W	-
Decorative LED 34W	-
Decorative LED 42W	-
Decorative LED 80W	-
Decorative LED 100W	-

Table 8.6: Streetlight Asset Prices RT9

Light Specification	Annual Charge % Change
50W MV	-4.3%
70W MV	-4.3%
80W MV	-4.3%
150W MV	-4.3%
250W MV	-4.3%
400W MV	-4.3%
40W FLU	-4.3%
80W HPS	-4.3%
125W HPS	-4.3%
100W INC	-4.3%
80W MH	-4.3%
125W MH	-4.3%
22W LED	0.0%

8.2.3 Metered Demand Prices

The % changes in the following table are applicable for reference tariff: RT5.

Table 8.7: Metered Demand Prices RT5

	Transmission		Distribution		Bundled Tariff	
Demand (kVA) (Lower to upper threshold)	Fixed % Change	Demand (in excess of lower threshold) % Change	Fixed % Change	Demand (in excess of lower threshold) % Change	Fixed % Change	Demand (in excess of lower threshold) % Change
0 to 300		12.3%	6.9%	7.1%	6.9%	8.3%
300 to 1000	12.3%	12.3%	7.1%	9.6%	8.2%	10.3%
1000 to 1500	12.3%	12.3%	8.7%	8.1%	9.5%	9.3%

The % changes in the following table are applicable for reference tariff: RT6.

Table 8.8: Percent changes for reference tariff RT6

	Transmission		Distribution		Bundled Tariff	
Demand (kVA) (Lower to upper threshold)	Fixed % Changes	Demand (in excess of lower threshold) % Changes	Fixed % Change	Demand (in excess of lower threshold) % Change	Fixed % Change	Demand (in excess of lower threshold) % Change
0 to 300		12.3%	5.3%	6.9%	5.3%	8.1%
300 to 1000	12.3%	12.3%	6.5%	8.7%	7.8%	9.5%
1000 to 1500	12.3%	12.3%	7.9%	6.3%	8.9%	7.7%

8.2.4 Demand Prices

The % changes in the following table are applicable for reference tariff: RT7 and RT8.

Table 8.9: Percent changes for reference tariff RT7 and RT8

Zone Substation	TNI	Pricing Zone	Transmission			Distribution			Bundled		
			Fixed charge for first 1000 kVA (c per annum)	Demand charge for 1000<kVA<7000 (c/kVA/annum)	Demand Charge for kVA > 7000 (c/kVA/annum)	Fixed charge for first 1000 kVA (c per annum)	Demand charge for 1000<kVA<7000 (c/kVA/annum)	Demand Charge for kVA > 7000 (c/kVA/annum)	Fixed charge for first 1000 kVA (c per annum)	Demand charge for 1000<kVA<7000 (c/kVA/annum)	Demand Charge for kVA > 7000 (c/kVA/annum)
Cook Street	WCKT	CBD	12.3%	12.3%	12.3%	4.0%	-1.9%	0.0%	6.4%	5.9%	6.0%
Forrest Avenue	WFRT	CBD	12.3%	12.3%	12.3%	4.0%	-1.9%	0.0%	6.4%	5.9%	6.0%
Hay Street	WHAY	CBD	12.3%	12.3%	12.3%	4.0%	-1.9%	0.0%	6.4%	5.9%	6.0%
Milligan Street	WMIL	CBD	12.3%	12.3%	12.3%	4.0%	-1.9%	0.0%	6.4%	5.9%	6.0%
Wellington Street	WWNT	CBD	12.3%	12.3%	12.3%	4.0%	-1.9%	0.0%	6.4%	5.9%	6.0%
Black Flag	WBKF	Goldfields Mining	12.3%	12.3%	12.3%	4.0%	-3.5%	0.0%	6.4%	9.4%	8.9%
Boulder	WBLD	Goldfields Mining	12.3%	12.3%	12.3%	4.0%	-3.5%	0.0%	6.4%	9.2%	8.7%
Bounty	WBNY	Goldfields Mining	12.3%	12.3%	12.3%	4.0%	-3.5%	0.0%	6.4%	10.5 %	10.0%
West Kalgoorlie	WWKT	Goldfields Mining	12.3%	12.3%	12.3%	4.0%	-3.5%	0.0%	6.4%	8.9%	8.4%
Albany	WALB	Mixed	12.3%	12.3%	12.3%	4.0%	-1.6%	0.0%	6.4%	7.6%	7.4%
Boddington	WBOD	Mixed	12.3%	12.3%	12.3%	4.0%	-1.6%	0.0%	6.4%	5.2%	5.5%
Bunbury Harbour	WBUH	Mixed	12.3%	12.3%	12.3%	4.0%	-1.6%	0.0%	6.4%	5.1%	5.4%
Busselton	WBSN	Mixed	12.3%	12.3%	12.3%	4.0%	-1.6%	0.0%	6.4%	6.4%	6.4%
Byford	WBYF	Mixed	12.3%	12.3%	12.3%	4.0%	-1.6%	0.0%	6.4%	5.4%	5.6%
Capel	WCAP	Mixed	12.3%	12.3%	12.3%	4.0%	-1.6%	0.0%	6.4%	6.0%	6.1%
Chapman	WCPN	Mixed	12.3%	12.3%	12.3%	4.0%	-1.6%	0.0%	6.4%	7.0%	6.9%
Darlington	WDTN	Mixed	12.3%	12.3%	12.3%	4.0%	-1.6%	0.0%	6.4%	5.7%	5.9%

Zone Substation	TNI	Pricing Zone	Transmission			Distribution			Bundled		
			Fixed charge for first 1000 kVA (c per annum)	Demand charge for 1000<kVA<7000 (c/kVA/annum)	Demand Charge for kVA > 7000 (c/kVA/annum)	Fixed charge for first 1000 kVA (c per annum)	Demand charge for 1000<kVA<7000 (c/kVA/annum)	Demand Charge for kVA > 7000 (c/kVA/annum)	Fixed charge for first 1000 kVA (c per annum)	Demand charge for 1000<kVA<7000 (c/kVA/annum)	Demand Charge for kVA > 7000 (c/kVA/annum)
Durlacher Street	WDUR	Mixed	12.3%	12.3%	12.3%	4.0%	-1.6%	0.0%	6.4%	6.6%	6.6%
Eneabba	WENB	Mixed	12.3%	12.3%	12.3%	4.0%	-1.6%	0.0%	6.4%	6.4%	6.4%
Geraldton	WGTN	Mixed	12.3%	12.3%	12.3%	4.0%	-1.6%	0.0%	6.4%	6.6%	6.6%
Marriott Road	WMRR	Mixed	12.3%	12.3%	12.3%	4.0%	-1.6%	0.0%	6.4%	5.0%	5.3%
Muchea	WMUC	Mixed	12.3%	12.3%	12.3%	4.0%	-1.6%	0.0%	6.4%	5.7%	5.9%
Northam	WNOR	Mixed	12.3%	12.3%	12.3%	4.0%	-1.6%	0.0%	6.4%	6.7%	6.7%
Picton	WPIC	Mixed	12.3%	12.3%	12.3%	4.0%	-1.6%	0.0%	6.4%	5.4%	5.6%
Rangeway	WRAN	Mixed	12.3%	12.3%	12.3%	4.0%	-1.6%	0.0%	6.4%	6.8%	6.8%
Sawyers Valley	WSVY	Mixed	12.3%	12.3%	12.3%	4.0%	-1.6%	0.0%	6.4%	6.4%	6.4%
Yanchep	WYCP	Mixed	12.3%	12.3%	12.3%	4.0%	-1.6%	0.0%	6.4%	5.7%	5.8%
Yilgarn	WYLN	Mixed	12.3%	12.3%	12.3%	4.0%	-1.6%	0.0%	6.4%	7.4%	7.2%
Baandee	WBDE	Rural	12.3%	12.3%	12.3%	4.0%	-3.6%	0.0%	6.4%	9.4%	8.9%
Beenup	WBNP	Rural	12.3%	12.3%	12.3%	4.0%	-3.6%	0.0%	6.4%	9.6%	9.1%
Bridgetown	WBTN	Rural	12.3%	12.3%	12.3%	4.0%	-3.6%	0.0%	6.4%	8.3%	7.9%
Carrabin	WCAR	Rural	12.3%	12.3%	12.3%	4.0%	-3.6%	0.0%	6.4%	9.7%	9.1%
Collie	WCOE	Rural	12.3%	12.3%	12.3%	4.0%	-3.6%	0.0%	6.4%	8.8%	8.3%
Coolup	WCLP	Rural	12.3%	12.3%	12.3%	4.0%	-3.6%	0.0%	6.4%	9.1%	8.6%
Cunderdin	WCUN	Rural	12.3%	12.3%	12.3%	4.0%	-3.6%	0.0%	6.4%	9.2%	8.7%
Katanning	WKAT	Rural	12.3%	12.3%	12.3%	4.0%	-3.6%	0.0%	6.4%	9.0%	8.5%
Kellerberrin	WKEL	Rural	12.3%	12.3%	12.3%	4.0%	-3.6%	0.0%	6.4%	9.4%	8.8%
Kojonup	WKOJ	Rural	12.3%	12.3%	12.3%	4.0%	-3.6%	0.0%	6.4%	7.9%	7.6%
Kondinin	WKDN	Rural	12.3%	12.3%	12.3%	4.0%	-3.6%	0.0%	6.4%	8.2%	7.7%
Manjimup	WMJP	Rural	12.3%	12.3%	12.3%	4.0%	-3.6%	0.0%	6.4%	8.3%	7.8%

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Margaret River	WMRV	Rural	12.3%	12.3%	12.3%	4.0%	-3.6%	0.0%	6.4%	9.0%	8.5%
Merredin	WMER	Rural	12.3%	12.3%	12.3%	4.0%	-3.6%	0.0%	6.4%	9.1%	8.6%
Moora	WMOR	Rural	12.3%	12.3%	12.3%	4.0%	-3.6%	0.0%	6.4%	8.3%	7.9%
Mount Barker	WMBR	Rural	12.3%	12.3%	12.3%	4.0%	-3.6%	0.0%	6.4%	9.1%	8.6%
Narrogin	WNGN	Rural	12.3%	12.3%	12.3%	4.0%	-3.6%	0.0%	6.4%	9.4%	8.9%
Pinjarra	WPNJ	Rural	12.3%	12.3%	12.3%	4.0%	-3.6%	0.0%	6.4%	7.2%	7.0%
Regans	WRGN	Rural	12.3%	12.3%	12.3%	4.0%	-3.6%	0.0%	6.4%	8.4%	7.9%
Three Springs	WTSG	Rural	12.3%	12.3%	12.3%	4.0%	-3.6%	0.0%	6.4%	8.3%	7.9%
Wagerup	WWGP	Rural	12.3%	12.3%	12.3%	4.0%	-3.6%	0.0%	6.4%	7.0%	6.8%
Wagin	WWAG	Rural	12.3%	12.3%	12.3%	4.0%	-3.6%	0.0%	6.4%	9.0%	8.5%
Wundowie	WWUN	Rural	12.3%	12.3%	12.3%	4.0%	-3.6%	0.0%	6.4%	8.7%	8.2%
Yerbillon	WYER	Rural	12.3%	12.3%	12.3%	4.0%	-3.6%	0.0%	6.4%	9.6%	9.0%
Amherst	WAMT	Urban	12.3%	12.3%	12.3%	4.0%	-8.2%	0.0%	6.4%	9.1%	8.3%
Arkana	WARK	Urban	12.3%	12.3%	12.3%	4.0%	-8.2%	0.0%	6.4%	9.1%	8.3%
Australian Paper Mills	WAPM	Urban	12.3%	12.3%	12.3%	4.0%	-8.2%	0.0%	6.4%	9.1%	8.3%
Balcatta	WBCT	Urban	12.3%	12.3%	12.3%	4.0%	-8.2%	0.0%	6.4%	9.1%	8.3%
Beechboro	WBCH	Urban	12.3%	12.3%	12.3%	4.0%	-8.2%	0.0%	6.4%	9.1%	8.3%
Belmont	WBEL	Urban	12.3%	12.3%	12.3%	4.0%	-8.2%	0.0%	6.4%	9.1%	8.3%
Bentley	WBTY	Urban	12.3%	12.3%	12.3%	4.0%	-8.2%	0.0%	6.4%	9.1%	8.3%
Bibra Lake	WBIB	Urban	12.3%	12.3%	12.3%	4.0%	-8.2%	0.0%	6.4%	9.1%	8.3%
British Petroleum	WBPM	Urban	12.3%	12.3%	12.3%	4.0%	-8.2%	0.0%	6.4%	9.1%	8.3%
Canning Vale	WCVE	Urban	12.3%	12.3%	12.3%	4.0%	-8.2%	0.0%	6.4%	9.1%	8.3%

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Clarence Street	WCLN	Urban	12.3%	12.3%	12.3%	4.0%	-8.2%	0.0%	6.4%	9.1%	8.3%
Clarkson	WCKN	Urban	12.3%	12.3%	12.3%	4.0%	-8.2%	0.0%	6.4%	9.1%	8.3%
Cockburn Cement	WCCT	Urban	12.3%	12.3%	12.3%	4.0%	-8.2%	0.0%	6.4%	9.1%	8.3%
Collier	WCOL	Urban	12.3%	12.3%	12.3%	4.0%	-8.2%	0.0%	6.4%	9.1%	8.3%
Cottesloe	WCTE	Urban	12.3%	12.3%	12.3%	4.0%	-8.2%	0.0%	6.4%	9.1%	8.3%
Edmund Street	WEDD	Urban	12.3%	12.3%	12.3%	4.0%	-8.2%	0.0%	6.4%	9.1%	8.3%
Forrestfield	WFFD	Urban	12.3%	12.3%	12.3%	4.0%	-8.2%	0.0%	6.4%	9.1%	8.3%
Gosnells	WGNL	Urban	12.3%	12.3%	12.3%	4.0%	-8.2%	0.0%	6.4%	9.1%	8.3%
Hadfields	WHFS	Urban	12.3%	12.3%	12.3%	4.0%	-8.2%	0.0%	6.4%	9.1%	8.3%
Hazelmere	WHZM	Urban	12.3%	12.3%	12.3%	4.0%	-8.2%	0.0%	6.4%	9.1%	8.3%
Henley Brook	WHBK	Urban	12.3%	12.3%	12.3%	4.0%	-8.2%	0.0%	6.4%	9.1%	8.3%
Herdsman Parade	WHEP	Urban	12.3%	12.3%	12.3%	4.0%	-8.2%	0.0%	6.4%	9.1%	8.3%
Joel Terrace	WJTE	Urban	12.3%	12.3%	12.3%	4.0%	-8.2%	0.0%	6.4%	9.1%	8.3%
Joondalup	WJDP	Urban	12.3%	12.3%	12.3%	4.0%	-8.2%	0.0%	6.4%	9.1%	8.3%
Kalamunda	WKDA	Urban	12.3%	12.3%	12.3%	4.0%	-8.2%	0.0%	6.4%	9.1%	8.3%
Kambalda	WKBA	Urban	12.3%	12.3%	12.3%	4.0%	-8.2%	0.0%	6.4%	10.4 %	9.5%
Kewdale	WKDL	Urban	12.3%	12.3%	12.3%	4.0%	-8.2%	0.0%	6.4%	9.1%	8.3%
Landsdale	WLDE	Urban	12.3%	12.3%	12.3%	4.0%	-8.2%	0.0%	6.4%	9.1%	8.3%
Maddington	WMDN	Urban	12.3%	12.3%	12.3%	4.0%	-8.2%	0.0%	6.4%	9.1%	8.3%
Malaga	WMLG	Urban	12.3%	12.3%	12.3%	4.0%	-8.2%	0.0%	6.4%	9.1%	8.3%
Mandurah	WMHA	Urban	12.3%	12.3%	12.3%	4.0%	-8.2%	0.0%	6.4%	9.1%	8.3%
Manning Street	WMAG	Urban	12.3%	12.3%	12.3%	4.0%	-8.2%	0.0%	6.4%	9.1%	8.3%

Zone Substation	TNI	Pricing Zone	Transmission			Distribution			Bundled		
			Fixed charge for first 1000 kVA (c per annum)	Demand charge for 1000<kVA<7000 (c/kVA/annum)	Demand Charge for kVA > 7000 (c/kVA/annum)	Fixed charge for first 1000 kVA (c per annum)	Demand charge for 1000<kVA<7000 (c/kVA/annum)	Demand Charge for kVA > 7000 (c/kVA/annum)	Fixed charge for first 1000 kVA (c per annum)	Demand charge for 1000<kVA<7000 (c/kVA/annum)	Demand Charge for kVA > 7000 (c/kVA/annum)
Mason Road	WMSR	Urban	12.3%	12.3%	12.3%	4.0%	-8.2%	0.0%	6.4%	9.1%	8.3%
Meadow Springs	WMSS	Urban	12.3%	12.3%	12.3%	4.0%	-8.2%	0.0%	6.4%	9.1%	8.3%
Medical Centre	WMCR	Urban	12.3%	12.3%	12.3%	4.0%	-8.2%	0.0%	6.4%	9.1%	8.3%
Medina	WMED	Urban	12.3%	12.3%	12.3%	4.0%	-8.2%	0.0%	6.4%	9.1%	8.3%
Midland Junction	WMJX	Urban	12.3%	12.3%	12.3%	4.0%	-8.2%	0.0%	6.4%	9.1%	8.3%
Morley	WMOY	Urban	12.3%	12.3%	12.3%	4.0%	-8.2%	0.0%	6.4%	9.1%	8.3%
Mullaloo	WMUL	Urban	12.3%	12.3%	12.3%	4.0%	-8.2%	0.0%	6.4%	9.1%	8.3%
Mundaring Weir	WMWR	Urban	12.3%	12.3%	12.3%	4.0%	-8.2%	0.0%	6.4%	9.1%	8.3%
Munday	WMDY	Urban	12.3%	12.3%	12.3%	4.0%	-8.2%	0.0%	6.4%	9.1%	8.3%
Murdoch	WMUR	Urban	12.3%	12.3%	12.3%	4.0%	-8.2%	0.0%	6.4%	9.1%	8.3%
Myaree	WMYR	Urban	12.3%	12.3%	12.3%	4.0%	-8.2%	0.0%	6.4%	9.1%	8.3%
Nedlands	WNED	Urban	12.3%	12.3%	12.3%	4.0%	-8.2%	0.0%	6.4%	9.1%	8.3%
North Beach	WNBH	Urban	12.3%	12.3%	12.3%	4.0%	-8.2%	0.0%	6.4%	9.1%	8.3%
North Fremantle	WNFL	Urban	12.3%	12.3%	12.3%	4.0%	-8.2%	0.0%	6.4%	9.1%	8.3%
North Perth	WNPH	Urban	12.3%	12.3%	12.3%	4.0%	-8.2%	0.0%	6.4%	9.1%	8.3%
O'Connor	WOCN	Urban	12.3%	12.3%	12.3%	4.0%	-8.2%	0.0%	6.4%	9.1%	8.3%
Osborne Park	WOPK	Urban	12.3%	12.3%	12.3%	4.0%	-8.2%	0.0%	6.4%	9.1%	8.3%
Padbury	WPBY	Urban	12.3%	12.3%	12.3%	4.0%	-8.2%	0.0%	6.4%	9.1%	8.3%
Piccadilly	WPCY	Urban	12.3%	12.3%	12.3%	4.0%	-8.2%	0.0%	6.4%	10.2 %	9.4%
Riverton	WRTN	Urban	12.3%	12.3%	12.3%	4.0%	-8.2%	0.0%	6.4%	9.1%	8.3%
Rivervale	WRVE	Urban	12.3%	12.3%	12.3%	4.0%	-8.2%	0.0%	6.4%	9.1%	8.3%
Rockingham	WROH	Urban	12.3%	12.3%	12.3%	4.0%	-8.2%	0.0%	6.4%	9.1%	8.3%

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Shenton Park (old)	WSPA	Urban	12.3%	12.3%	12.3%	4.0%	-8.2%	0.0%	6.4%	9.1%	8.3%
Shenton Park (new)	WSPK	Urban	12.3%	12.3%	12.3%	4.0%	-8.2%	0.0%	6.4%	9.1%	8.3%
Sth Ftle Power Station	WSFT	Urban	12.3%	12.3%	12.3%	4.0%	-8.2%	0.0%	6.4%	9.1%	8.3%
Southern River	WSNR	Urban	12.3%	12.3%	12.3%	4.0%	-8.2%	0.0%	6.4%	9.1%	8.3%
Tate Street	WTTS	Urban	12.3%	12.3%	12.3%	4.0%	-8.2%	0.0%	6.4%	9.1%	8.3%
University	WUNI	Urban	12.3%	12.3%	12.3%	4.0%	-8.2%	0.0%	6.4%	9.1%	8.3%
Victoria Park	WVPA	Urban	12.3%	12.3%	12.3%	4.0%	-8.2%	0.0%	6.4%	9.1%	8.3%
Waikiki	WWAI	Urban	12.3%	12.3%	12.3%	4.0%	-8.2%	0.0%	6.4%	9.1%	8.3%
Wangara	WWGA	Urban	12.3%	12.3%	12.3%	4.0%	-8.2%	0.0%	6.4%	9.1%	8.3%
Wanneroo	WWNO	Urban	12.3%	12.3%	12.3%	4.0%	-8.2%	0.0%	6.4%	9.1%	8.3%
Welshpool	WWEL	Urban	12.3%	12.3%	12.3%	4.0%	-8.2%	0.0%	6.4%	9.1%	8.3%
Wembley Downs	WWDN	Urban	12.3%	12.3%	12.3%	4.0%	-8.2%	0.0%	6.4%	9.1%	8.3%
Willetton	WWLN	Urban	12.3%	12.3%	12.3%	4.0%	-8.2%	0.0%	6.4%	9.1%	8.3%
Yokine	WYKE	Urban	12.3%	12.3%	12.3%	4.0%	-8.2%	0.0%	6.4%	9.1%	8.3%

8.2.5 Demand-Length Prices

The % changes 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 8.10: Demand Length Prices RT5, RT6, RT7, RT8 and RT11

Pricing Zone	For kVA >1000 and first 10 km length % Change	For kVA >1000 and length in excess of 10 km % Change
CBD	N/A	N/A
Urban	2.6%	3.6%
Mining	3.7%	3.7%
Mixed	3.7%	2.4%
Rural	3.3%	2.7%

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

Table 8.11: Demand-Length Charge RT7, RT8 and RT11

Pricing Zone	For first 10 km length % Change	For length in excess of 10 km % Change
CBD	N/A	N/A
Urban	2.5%	2.8%
Mining	4.7%	4.3%
Mixed	4.1%	3.3%
Rural	**4.6%**	**2.4%**

8.2.6 Administration Prices

The % changes in the following table are applicable for reference tariffs: RT7 and RT8.

Table 8.12: Administration Prices RT7 and RT8

Peak Demand	% Change
>=7,000 kVA	2.6%
<7,000 kVA	2.8%

8.2.7 Low Voltage Prices

The % changes in the following table are applicable for reference tariff: RT8.

Table 8.13: Low Voltage Prices RT8

	% Change
Fixed	4.8%
Demand	6.9%

8.2.8 Connection Prices

The % changes in the following table are applicable for reference tariff: RT11.

Table 8.14: Connection Prices RT11

	% Change
Connection Price	12.3%

8.2.9 Transmission Use of System Prices

The % changes in the following table are applicable for reference tariff: TRT1.

Table 8.15: Transmission Use of System Prices TRT1

Substation	TNI	% Change
Albany	WALB	12.3%
Alcoa Pinjarra	WAPJ	12.3%
Amherst	WAMT	12.3%
Arkana	WARK	12.3%
Australian Fused Materials	WAFM	12.3%
Australian Paper Mills	WAPM	12.3%
Baandee (WC)	WBDE	12.3%
Balcatta	WBCT	12.3%
Beckenham	WBEC	12.3%
Beechboro	WBCH	12.3%
Beenup	WBNP	12.3%
Belmont	WBEL	12.3%
Bentley	WBTY	12.3%
Bibra Lake	WBIB	12.3%
Binningup Desalination Plant	WBDP	12.3%

Substation	TNI	% Change
Black Flag	WBKF	12.3%
Boddington Gold Mine	WBGM	12.3%
Boddington	WBOD	12.3%
Boulder	WBLD	12.3%
Bounty	WBNY	12.3%
Bridgetown	WBTN	12.3%
British Petroleum	WBPM	12.3%
Broken Hill Kwinana	WBHK	12.3%
Bunbury Harbour	WBUH	12.3%
Busselton	WBSN	12.3%
Byford	WBYF	12.3%
Canning Vale	WCVE	12.3%
Capel	WCAP	12.3%
Carrabin	WCAR	12.3%
Cataby Kerr McGee	WKMC	12.3%
Chapman	WCPN	12.3%
Clarence Street	WCLN	12.3%
Clarkson	WCKN	12.3%
Cockburn Cement	WCCT	12.3%
Cockburn Cement Ltd	WCCL	12.3%
Collie	WCOE	12.3%
Collier	WCOL	12.3%
Cook Street	WCKT	12.3%
Coolup	WCLP	12.3%
Cottesloe	WCTE	12.3%
Cunderdin	WCUN	12.3%
Darlington	WDTN	12.3%
Edgewater	WEDG	12.3%

Substation	TNI	% Change
Edmund Street	WEDD	12.3%
Eneabba	WENB	12.3%
Forrest Ave	WFRT	12.3%
Forrestfield	WFFD	12.3%
Geraldton	WGTN	12.3%
Glen Iris	WGNI	12.3%
Golden Grove	WGGV	12.3%
Gosnells	WGNL	12.3%
Hadfields	WHFS	12.3%
Hay Street	WHAY	12.3%
Hazelmere	WHZM	12.3%
Henley Brook	WHBK	12.3%
Herdsman Parade	WHEP	12.3%
Joel Terrace	WJTE	12.3%
Joondalup	WJDP	12.3%
Kalamunda	WKDA	12.3%
Katanning	WKAT	12.3%
Kellerberrin	WKEL	12.3%
Kewdale	WKDL	12.3%
Kojonup	WKOJ	12.3%
Kondinin	WKDN	12.3%
Kwinana Alcoa	WAKW	12.3%
Kwinana Desalination Plant	WKDP	12.3%
Kwinana PWS	WKPS	12.3%
Landsdale	WLDE	12.3%
Maddington	WMDN	12.3%
Malaga	WMLG	12.3%
Mandurah	WMHA	12.3%

Substation	TNI	% Change
Manjimup	WMJP	12.3%
Manning Street	WMAG	12.3%
Margaret River	WMRV	12.3%
Marriott Road Barrack Silicon Smelter	WBSI	12.3%
Marriott Road	WMRR	12.3%
Mason Road	WMSR	12.3%
Mason Road CSBP	WCBP	12.3%
Mason Road Kerr McGee	WKMK	12.3%
Meadow Springs	WMSS	12.3%
Medical Centre	WMCR	12.3%
Medina	WMED	12.3%
Merredin 66kV	WMER	12.3%
Midland Junction	WMJX	12.3%
Milligan Street	WMIL	12.3%
Moora	WMOR	12.3%
Morley	WMOY	12.3%
Mt Barker	WMBR	12.3%
Muchea Kerr McGee	WKMM	12.3%
Muchea	WMUC	12.3%
Muja PWS	WMPS	12.3%
Mullaloo	WMUL	12.3%
Munday	WMDY	12.3%
Murdoch	WMUR	12.3%
Mundaring Weir	WMWR	12.3%
Myaree	WMYR	12.3%
Narrogin	WNGN	12.3%
Nedlands	WNED	12.3%
North Beach	WNBH	12.3%

Substation	TNI	% Change
North Fremantle	WNFL	12.3%
North Perth	WNPH	12.3%
Northam	WNOR	12.3%
Nowgerup	WNOW	12.3%
O'Connor	WOCN	12.3%
Osborne Park	WOPK	12.3%
Padbury	WPBY	12.3%
Parkeston	WPRK	12.3%
Parklands	WPLD	12.3%
Piccadilly	WPCY	12.3%
Picton 66kv	WPIC	12.3%
Pinjarra	WPNJ	12.3%
Rangeway	WRAN	12.3%
Regans	WRGN	12.3%
Riverton	WRTN	12.3%
Rivervale	WRVE	12.3%
Rockingham	WROH	12.3%
Sawyers Valley	WSVY	12.3%
Shenton Park	WSPA	12.3%
Southern River	WSNR	12.3%
South Fremantle	WSFT	12.3%
Summer St	WSUM	12.3%
Sutherland	WSRD	12.3%
Tate Street	WTTS	12.3%
Three Springs	WTSG	12.3%
Three Springs Terminal	WTST	12.3%
Tomlinson Street	WTLN	12.3%
University	WUNI	12.3%

Substation	TNI	% Change
Victoria Park	WVPA	12.3%
Wagerup	WWGP	12.3%
Wagin	WWAG	12.3%
Waikiki	WWAI	12.3%
Wangara	WWGA	12.3%
Wanneroo	WWNO	12.3%
Wellington Street	WWNT	12.3%
Welshpool	WWEL	12.3%
Wembley Downs	WWDN	12.3%
West Kalgoorlie	WWKT	12.3%
Western Collieries	WWCL	12.3%
Western Mining	WWMG	12.3%
Westralian Sands	WWSD	12.3%
Willetton	WWLN	12.3%
Worsley	WWOR	12.3%
Wundowie	WWUN	12.3%
Yanchep	WYCP	12.3%
Yerbillon	WYER	12.3%
Yilgarn	WYLN	12.3%
Yokine	WYKE	12.3%

The % changes in the following table are applicable for reference tariffs: RT11 and TRT2.

Table 8.16 Transmission Use of System Prices RT11 and TRT2

Substation	TNI	% Change
Albany	WALB	12.3%
Boulder	WBLD	12.3%
Bluewaters	WBWP	12.3%
Cockburn PWS	WCKB	12.2%
Collgar	WCGW	12.2%
Collie PWS	WCPS	12.3%
Emu Downs	WEMD	12.3%
Geraldton	WGTN	12.3%
Greenough Solar Farm	TMGS	12.3%
Kemerton PWS	WKEM	12.3%
Kwinana Alcoa	WAKW	12.3%
Kwinana Donaldson Road	WKND	12.3%
Kwinana PWS	WKPS	12.2%
Landwehr (Alinta)	WLWT	12.3%
Mason Road	WMSR	12.3%
Merredin Power Station	TMDP	12.3%
Muja PWS	WMPS	12.3%
Mumbida Wind Farm	TMBW	12.3%
Mungarra GTs	WMGA	12.2%
Newgen Kwinana	WNGK	12.2%
Newgen Neerabup	WGNN	12.3%
Oakley (Alinta)	WOLY	12.3%
Parkeston	WPKS	12.3%
Pinjar GTs	WPJR	12.3%
Alcoa Pinjarra	WAPJ	12.3%
Tiwest GT	WKMK	12.3%

Substation	TNI	% Change
Wagerup	WWGP	12.3%
Walkaway Windfarm	WWWF	12.3%
West Kalgoorlie GTs	WWKT	12.2%
Worsley	WWOR	12.3%

8.2.10 Common Service Prices

The % changes in the following table are applicable for reference tariff: TRT1.

Table 8.17: Common Service Prices TRT1

	% Change
Common Service Price	12.3%

8.2.11 Control System Service Prices

The % changes in the following table are applicable for reference tariff: RT11 and TRT2.

Table 8.18: Control System Service Prices RT11 and TRT2

	% Change
Control System Service Price (Generators)	7.8%

The % changes in the following table are applicable for reference tariff: TRT1.

Table 8.19: Control System Service Prices TRT1

	% Change
Control System Service Price (Loads)	12.3%

8.2.12 Metering Prices

The % changes in the following table are applicable for reference tariffs: TRT1 and TRT2.

Table 8.20: Metering Prices TRT1 and TRT2

	% Change
Transmission Metering	-46.8

Appendix A

A.1 Price Setting for New Transmission Nodes Policy

This policy applies when a new transmission node is established.

Transmission "use of system" prices for both entry and exit points are derived using the computer based analysis tool T-Price, based on historical load flow information. In the case of new sites, historical data is not available.

However, there is a need for both Western Power and the prospective user to have a fairly accurate TUOS price and connection price. Western Power requires the prices to determine future revenues from the connection, and any associated capital contribution. The user requires the price and capital contribution for the purposes of project feasibility, and their internal approval processes.

This policy addresses this issue by providing a degree of price certainty over the medium term.

Policy Statement – Transmission Use of System Price (TUOS)

This policy will apply to new connection points on the transmission and distribution system where the prospect is that it will be a single connection point.

1. Western Power will nominate a TUOS price consistent with all the principles described in this document based on the best available knowledge of the network parameters including asset values and expected load flows. This would also include necessary assumptions for maximum demand and utilisation at the new connection and also any other new or forecast connections.
2. That nominated nodal TUOS price will then be adjusted annually in line with the CMD weighted average TUOS price adjustment for all other load or generator transmission nodes (as applicable).
3. Once that connection point is established the nominated TUOS price (adjusted in accordance with step 2) will apply at the commencement of the access contract, with annual price adjustments at the start of each financial year of no greater than (plus or minus) the annual pricing side constraint as detailed in the *access arrangement*. (Thus, the nominated TUOS price will converge over time with and future price based on future T-Price runs.)
4. The TUOS price will be published once the connection point is commissioned.
5. Where another user subsequently connects to such a connection point the price that will apply will be the price applying to that connection point at the time.
6. The common service, metering and control system prices that apply in this circumstance will be the standard published prices.

Policy Statement – Transmission Connection Price

The transmission connection price, for new connections where there was no previous connection point, is determined in accordance with the principles described below. There are two categories in which the new connection point can fit.

A connection that is unlikely to be shared by other users.

In this case the connection asset would be dedicated to the single user. The asset can be constructed either by the user or by Western Power, and the user has the option to own the asset or to allow Western Power to own the asset.

Where Western Power will own the asset the capital contribution for the connection asset will be as determined by the Contributions Policy.

The annual connection price is calculated to recover to expected operations and maintenance costs for the connection asset and is currently set at 1.88% of the full capital cost. This percentage is based on the average of the ratio of the forecast Operations and Maintenance cost and the GODV of the transmission network over the *access arrangement* period. Once the annual connection price has been determined for a particular connection point, the price is adjusted annually by the all capitals consumer price index (**CPI**).

A connection point where there is a high likelihood that other users will connect in the future.

In this circumstance the user still retains the option of owning the connection asset. If the user prefers this option Western Power may require the ability to build connection assets for other users on the same site. Where the user does select this option the calculation of the capital contribution and the associated connection access price is on the same basis as the first option.

Where the user would prefer Western Power to own the connection asset, the connection access price would be the published price that applies to all multi-user substations within the Western Power Network. This published price would be used by Western Power to calculate the capital contribution for the connection asset.

Western Power will offer this option at its discretion depending on the likelihood of future users connecting to the connection point.