2012/13 Price List Information

ELECTRICITY NETWORKS CORPORATION
("WESTERN POWER")

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1 Introduction

This document is Western Power's Price List Information, as defined in the Electricity Networks Access Code 2004 (the Code).

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; and
- 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 Economic Regulation Authority (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.

1.2 2012/13 Foreword

This document is the Price List Information for the 2012/13 Price List. The prices in the Price List will only commence following approval of the amended proposed revisions to the access arrangement by the Authority. The prices in this document assume the revisions commencement date to be 1 February 2013.

1.2.1 Modelling a mid-year price change

The access arrangement contains revenue caps for the whole of 2012/13. However, the financial year is split into two parts for pricing purposes: the first part commenced on 1 July 2012 and involved no changes to existing tariffs; the second part will begin on 1 February 2013. The prices due to commence from 1 February are set in such a way that the total revenue earned throughout 2012/13 is equal to the 2012/13 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.

1.2.2 New bi-directional tariffs

Western Power's amended revisions to the Access Arrangement include four new reference services, with associated reference tariffs, for bi-directional energy flows.

In its Draft Decision for AA2 (dated 16 July 2009), the Authority required Western Power to introduce one or more reference services to cater for the requirements for network services that arise where small-scale renewable energy systems connect to the network and where electricity consumers participate in the Renewable Energy Buyback Scheme (REBS). Western Power responded to this Required Amendment in its third submission, dated 5 October 2009, by setting out its proposed residential bi-directional reference service and charging arrangements.

Western Power proposed that a new Reference Service “C1” and an associated Reference Tariff “RT12” would be available to new and existing residential users with bi-directional energy flows due to small scale embedded generator (inverter connected).

In the Final Decision for AA2 (dated 4 December 2009) the Authority accepted that Western Power’s proposed reference service would satisfy the requirements for approval of the access arrangement.

However due to concerns raised by stakeholders, primarily relating to implementation costs, this reference service and the associated reference tariff has not been sought by users during AA2.

For AA3, Ernst & Young were engaged by Western Power to review the existing Reference Service and Reference Tariff for residential distribution users with bi-directional energy flows due to small scale generation, and, in addition, define a new Reference Service and Reference Tariff for commercial users. The review included extensive consultation with key stakeholders.

The new proposed bi-directional reference services and reference tariffs are a result of that review. The report provided by Ernst & Young was included in the initial submission made in September (AAI Appendix Z – Ernst & Young Report – Bi-directional Tariff Reference Services and Associated Tariff). In summary the review concluded that four new reference services should be proposed in AA3:

Reference Service	Reference Tariff
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

In addition the review concluded that, at this time, following an analysis of the advantages and disadvantages of all issues and costs identified, the most efficient tariff structures are to mirror existing tariffs, as follows:

New Reference Tariff	Identical to
RT13	RT1
RT14	RT2
RT15	RT3
RT16	RT4

In its Final Decision on AA3, the Authority required the proposed bi-directional reference services and tariffs to not extend to battery storage and electric vehicles (which were included in the original proposal).

Note that, to avoid confusion with the previously offered bi-directional service, reference tariff “RT12” is no longer related to reference service C1 and has been removed from the Price List.

1.2.2.1. Implementation and reporting in 2012/13

The new bi-directional reference services and reference tariffs will be available from 1 February 2013. Western Power understands that changes may be required to retailers' systems to support the new reference services which may take six months or longer. Western Power will work with retailers to ensure a smooth implementation. In the interim, retailers may seek a non-reference service from Western Power.

It is expected that most customers will only commence using the proposed services from 1 July 2013 or later. Due to the tariffs being equivalent to existing tariffs this will present no problems in terms of overall revenue recovery.

[For this reason, there will be no customers reported as being on bi-directional services in the 2013/14 version of this document as it will be prepared in April 2013.]

1.2.3 Tariff rebalancing

During AA2, rather than adjusting individual tariffs by different amounts, the decision was made (in order to reduce price shock to individual customer groups) to increase all network tariffs by the same amount each year. The intention during the AA3 period is to restore tariffs to the appropriate level by performing some minor re-balancing between tariffs as allowed by the side constraints.

1.2.4 Streetlight tariff changes

Two modifications are being made to the streetlight tariff (RT9) in 2012/13. The first is to update the list of streetlight asset types available. This list has been incomplete for some time, and will now reflect the full range of streetlights installed on the network.

The second change is to divide the asset types (in section 5.1.2 of the Price List) into current and obsolete. Current types are still offered and installed, whereas obsolete are existing streetlight types that will no longer be offered for new installations. This change is intended to provide further clarity as to what streetlight types are available for installation. There will be no pricing impact to customers as the newly published prices reflect the prices that would have been charged had this change not been implemented.

For the avoidance of doubt, the following table illustrates the mapping to the prices previously charged:

Asset type	Previous charge
40W FLU	50W MV
60W INC	50W MV
60W MV	50W MV
70W MV	80W MV
80W HPS	70W HPS
80W MH	80W MV
100W INC	50W MV
125W HPS	150W HPS
125W MH	150W MH
150W MV	125W MV

1.3 History of the Tariffs

Prior to the commencement of the Code and the first Access Arrangement Western Power had in place a suite of tariffs to recover the regulated revenue for both the transmission and distribution network businesses.

Network tariffs have been in place since the introduction of de-regulation into the south-west electricity network in 1996. Initially tariffs were only determined and published for contestable users but from July 2001 network tariffs were established for all users whether contestable or franchise.

In July 2001 the network tariff structure changed somewhat from the structure in place before 2001. This became necessary to improve the efficiency of the tariff structure and to cater, in particular, for the smaller contestable and non-contestable users. Prior to 2001 the transmission and distribution access price structures were entirely different and users seeking access to the networks had separate transmission and distribution access contracts and paid separate charges.

Once the principle was established that access prices were required for all users and all users were to be charged for access, it became imperative to develop appropriate tariffs. This was achieved by a full review of the tariff structures and making the transmission and distribution tariff structures compatible, so that for distribution–connected users the tariffs could be added together at a component level to form a bundled tariff. The transmission and distribution tariffs settings were still separately determined through a transparent process.

With the exception of the introduction of bi-directional tariffs as discussed in section 1.2.2, Western Power has maintained the remaining network tariff structure for the reference services offered under the Access Arrangement since its commencement on 1 July 2006.

1.4 Revenue requirement for 2012/13

1.4.1 Maximum Transmission Regulated Revenue

The following table demonstrates the derivation of the maximum transmission regulated revenue for 2012/13 in accordance with section 5.6.6 of the Access Arrangement.

Table 1 – Maximum Transmission Regulated Revenue for 2012/13 ($M real as at 30 June 2012)

	2012/13
TR_t	387.3
plus $AA2_t$	0.0
plus TK_t	26.5
MTR_t	**413.8**
$MTR_{\text{July 2012 – January 2013}}$	**241.4**

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 1.4.3 for details of the inflation factor used) and annualised (see section 1.2.1).

Table 2 - Transmission Revenue Cap Revenue for 2012/13 ($M)

	Revenue (Real)	Revenue (Nominal)
Revenue Cap Revenue ($MTR_{2012/13}$)	413.8	423.1
Revenue Cap Revenue (Feb 2013 – Jun 2013)		176.3[1]
Revenue Cap Revenue (annualised)		423.1

1.4.2 Maximum Distribution Regulated Revenue

The following table demonstrates the derivation of the maximum distribution regulated revenue for 2012/13 in accordance with section 5.7.6 of the Access Arrangement.

Table 3 – Maximum Distribution Regulated Revenue for 2012/13 ($M real as at 30 June 2012)

	2012/13
DR_t	685.7
plus $AA2_t$	0.0
plus DK_t	49.1
MDR_t (not including TEC_t)	**734.8**
TEC_t ($M nominal)	**154.0**
$MDR_{July\ 2012\ –\ January\ 2013}$	**485.3**

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 1.4.3 for details of the inflation factor used) and annualised (see section 1.2.1).

Table 4 - Distribution Revenue Cap Revenue for 2012/13 ($M)

	Revenue (Real)	Revenue (Nominal)
MDR_t (not including TEC_t)	734.8	751.4
Revenue Cap Revenue ($MDR_{2012/13}$)		905.4
Revenue Cap Revenue (Feb 2013 – Jun 2013)		409.1[2]
Revenue Cap Revenue (annualised)		981.9

1.4.3 Derivation of Inflation Factor

In sections 1.4.1 and 1.4.2 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 5 - Derivation of 2012/13 Inflation Factor

December 2011 – December 2012 – Forecast	2.25%
Derived Inflation Factor	1.0225

[1] = (MTR_t – $MTR_{July\ 2012\ –\ January\ 2013}$) * inflation factor

[2] = Revenue Cap Revenue ($MDR_{2012/13}$) - $MDR_{July\ 2012\ –\ January\ 2013}$ * inflation factor

1.5 Forecast revenue recovery

The following table sets out the reference service revenue, by tariff, which is forecast to be collected when applying the 2012/13 Price List from 1 February.

Table 6 – Reference Service Revenue Forecast 1 Feb – 30 Jun 2013 ($M Nominal)

	kWh	Customer Numbers	Forecast Transmission Revenue Recovered	Forecast Distribution Revenue Recovered
TRT1 – Transmission Exit	N/A	26	13.6	0.0
TRT2 – Transmission Entry (includes LV Gens etc.)	N/A	29	28.0	0.0
RT1 - Anytime Energy (Residential)	2,216,364,979	928,361	48.2	214.1
RT2 - Anytime Energy (Business)	677,792,717	90,014	16.9	65.5
RT3 - Time of Use Energy (Residential)	88,861,994	24,799	2.3	8.4
RT4 - Time of Use Energy (Business)	837,145,708	12,687	20.1	51.2
RT5 - High Voltage Metered Demand	168,894,038	184	3.5	5.7
RT6 - Low Voltage Metered Demand	559,591,163	2,130	13.5	26.0
RT7 - High Voltage Contract Maximum Demand	1,287,102,504	335	26.4	19.2
RT8 - Low Voltage Contract Maximum Demand	99,900,262	84	2.8	4.4
RT9 – Streetlighting	50,664,668	240,095	0.7	13.0
RT10 - Unmetered Supplies	14,366,523	15,801	0.1	1.3
RT11 - Distribution Entry	N/A	21	0	0.3
RT13 – Anytime Energy (Residential) Bi-directional Service	0	0	0	-
RT14 – Anytime Energy (Business) Bi-directional Service	0	0	0	-
RT15 – Time of Use (Residential) Bi-directional Service	0	0	0	-
RT16 – Time of Use (Business) Bi-directional Service	0	0	0	-
Total Reference Service Revenue	**6,000,684,555**	**1,314,566**	**176.1**	**409.1**
Transmission Standby	**-**	**-**	**0.2**	**0**
TOTAL REVENUE CAP REVENUE	**6,000,684,555**	**1,314,566**	**176.3**	**409.1**
Over/(Under) recovery compared to maximum transmission/distribution regulated revenue			**0.0**	**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.

Note: Transmission and distribution are treated separately and each has independent target revenue for reference services.

The reference service revenue is recovered from users in a manner that is:

- Economically efficient;
- Transparent;
- Practical; and
- Equitable.

In addition to these objectives, the pricing methodology is developed to:

- Achieve the reference service revenue to maintain a viable network business and to deliver efficient network services to all network users;
- Be as cost reflective as is reasonable to reflect the network user's utilisation of the network including use of dedicated assets;
- Promote efficient use of the network through appropriate price signalling;
- Maintain price stability and certainty to enable network users to make informed investment decisions;
- Be as simple and straightforward as is reasonable taking into account other objectives; and
- Avoid cross subsidy between different user groups where possible. From an economic efficiency perspective this requires that the reference tariff be between the incremental cost of supply and the stand-alone cost of supply.

2.2 Pricing Principles

Western Power has adopted the following principles that are designed to meet the pricing objectives set out in the previous section.

1. Tariffs are designed to recover the revenue cap revenue entitlement while meeting any side constraints to prevent price shock to users.
2. The prices will be based on a well-defined and transparent methodology.
3. The prices will be based on analysis of the cost of supply provision that includes:
   a. Definition of the classes of service provided;
   b. Allocation of fixed and variable network costs to service classes; and
   c. Price setting to recover the fixed and variable costs.
4. Prices will signal the economic cost of supply provision in that they will:

a. Avoid cross subsidies between classes of service; and

b. Avoid cross subsidies between customers within each class of service.

5. Provided that economic costs are covered, prices will be responsive to user requirements in order to:

   a. Avoid economic bypass; and

   b. Allow for negotiation where provided within the Code.

6. Provide economic signals to encourage efficient use of the network.

7. Reference tariffs for users with annual energy demand below 1 MVA are uniform (consistent with the section 7.7 of the Code), but will meet the pricing principles described above, as far as is practical.

2.3 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. Further detail is provided in the remainder of this document.

2.3.1 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 user level and so users 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.

It is essential to separate the two processes of "determining cost of supply" and "setting reference tariffs" to recover those costs. In the ideal world the costs of supply can be clearly allocated to particular customer groups and the reference tariffs are set to exactly recover those costs. In addition, 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 that 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. These assumptions may introduce a degree of imprecision in tariff setting, but this is not considered to be significant and there is considerable historical precedence in deriving the network cost of supply that supports the approach.

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. The limitations on the metering information available will also introduce a degree of imprecision that cannot be avoided or readily quantified.

2.3.2 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 (300-1,000 kVA maximum demand)
- General Business Medium (100-300 kVA maximum demand)
- General Business Small (15-100 kVA maximum demand)
- Small Business (<15 kVA maximum demand)
- Residential
- Streetlights
- Unmetered Supplies

2.3.3 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.

Reference tariffs are derived from the cost of supply determination. The reference tariffs do not directly relate to the customer groups. This is because a number of the customer groups are based on derived user demands whereas the reference tariffs are based on the user and metering data that is actually available.

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.

2.3.4 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 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 networks and distribution networks.

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.

Transmission Network Assets

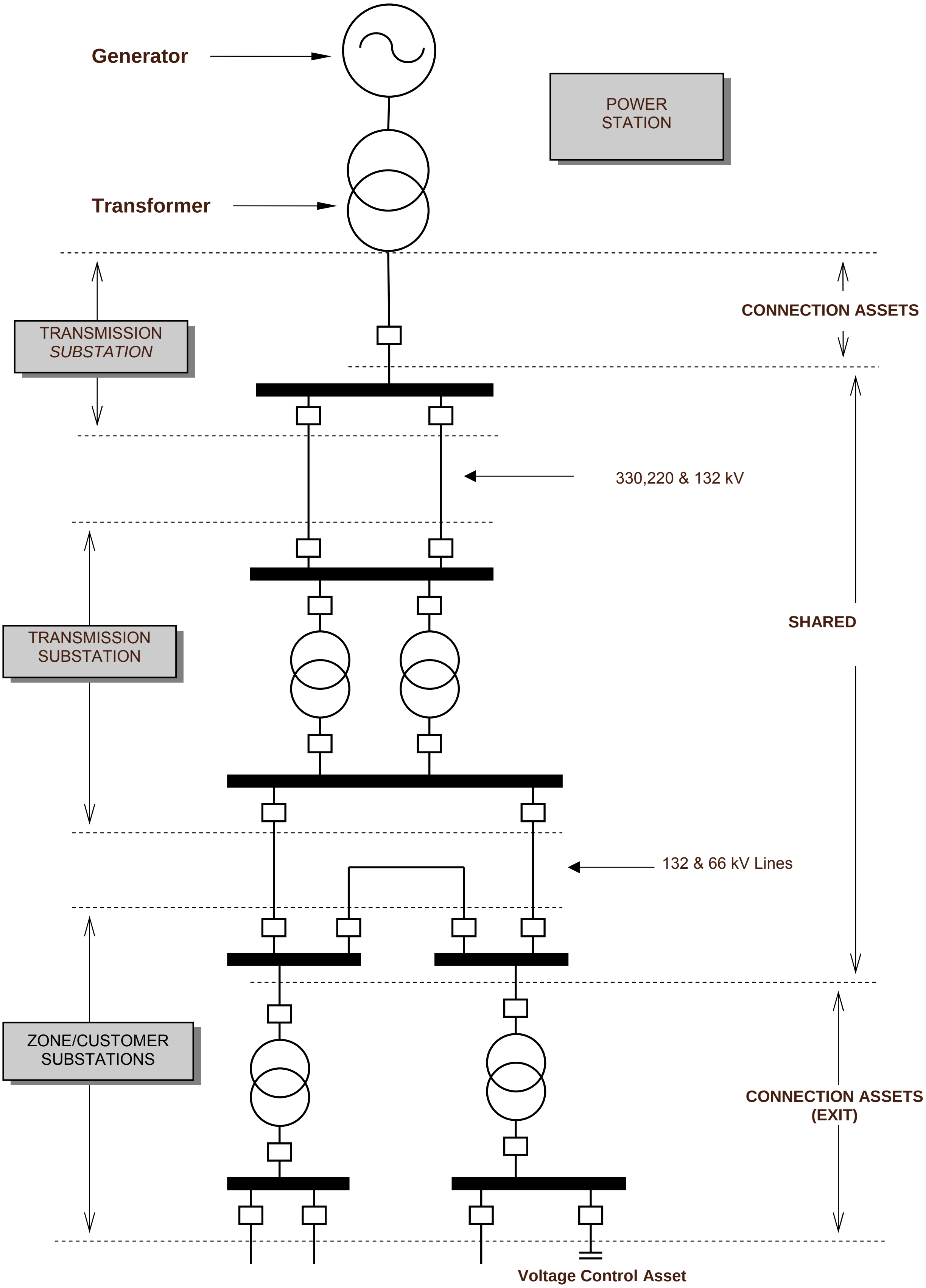

Figure 1 - Transmission Network Assets

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 2012/13:

Table 7 - Transmission Pricing Cost Pools for 2012/13 ($M Nominal annualised)

Cost Pool	Allocated Revenue
Entry Connection	8.6
Exit Connection HV	0.7
Exit Connection LV	103.6
Control System Services for Generators	3.0
Control System Services for Loads	17.2
Use Of System for Generators	53.7
Use Of System for Loads	134.3
Common Service for Loads (including Voltage Control)	100.9
Metering CT/VT	0.6
Standby	0.5
Total Revenue Cap Revenue	**423.1**

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 the Tariff Equalisation Contribution) 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 (300-1,000 kVA maximum demand)
- General Business Medium (100-300 kVA maximum demand)
- General Business Small (15-100 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. 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 the process followed is illustrated in the following flow diagram.

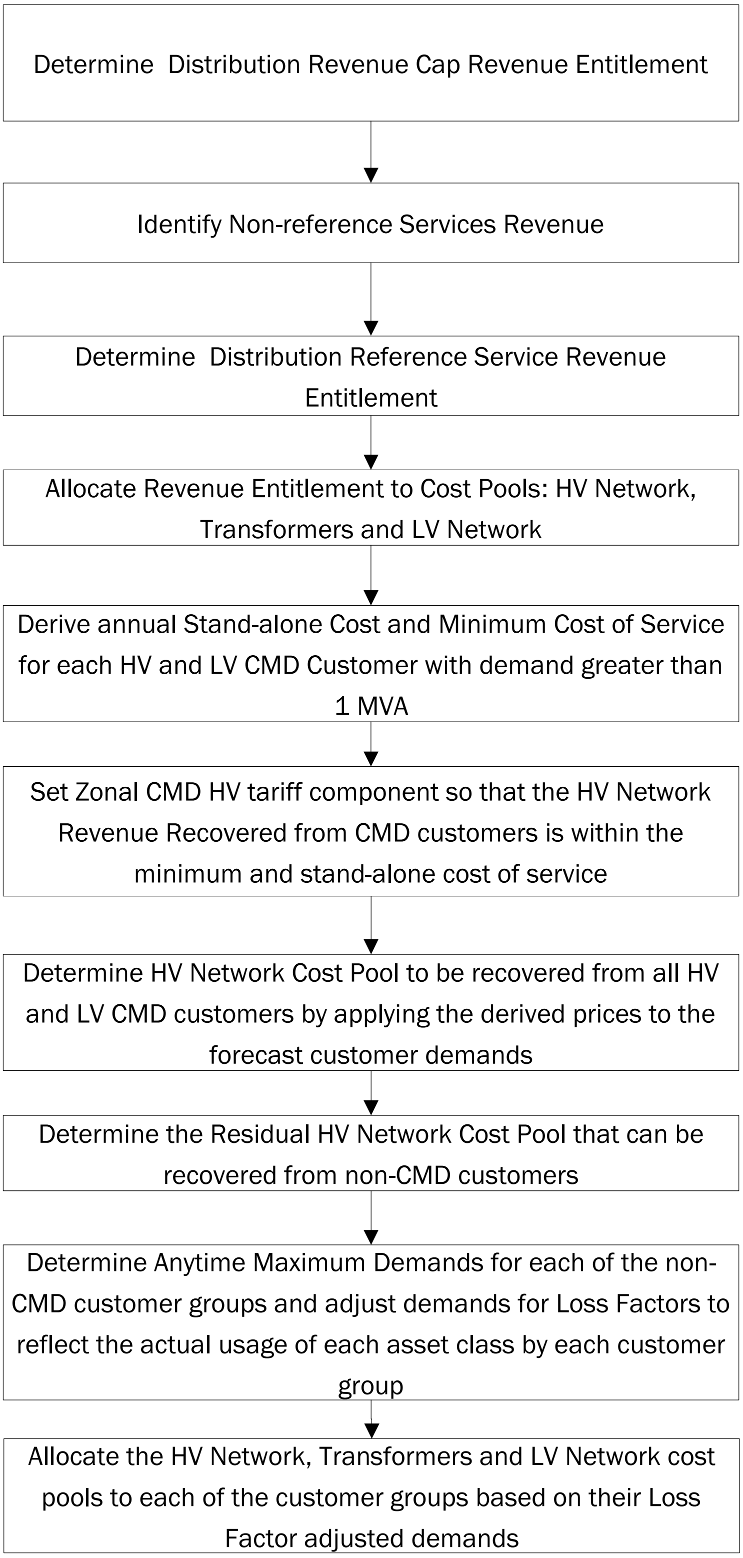

Figure 2 - Distribution Cost of Supply Flow Chart

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

It is assumed at this stage that the forecast distribution network revenue entitlement has been determined in accordance with the approach approved by the Authority in the Access Arrangement.

The forecast distribution network revenue entitlement 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 HV network, transformers and the 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 that 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 standalone 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 standalone 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 loss factors that are used are listed by customer group as follows:

Customer Group	Loss 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. That 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.

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 simply 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 clearly 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 O&M 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 >1,000 kVA	0.1
High Voltage	0

4.4.10 Allocation of Tariff Equalisation Contribution (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:

1. Allocation of HV Network Costs to customer groups
2. Allocation of Transformer Costs to customer groups
3. 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

The allocation of the streetlight asset costs is based on the average cost per light, as derived in the asset valuation, applied over the total asset.

4.4.12 Metering Costs

Metering costs are determined from asset information for the various customer groups and both capital and maintenance costs are allocated on a per user basis across each group.

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 detail the allocation of the distribution network revenue entitlement (which includes TEC) to the cost pools and customer groups:

Table 8 - Distribution Cost Pools for 2012/13 ($M Nominal annualised)

	Locational Zone					
Cost Pool	**CBD**	**Urban**	**Goldfields Mining**	**Mixed**	**Rural**	**Total**
High Voltage Network	5.6	145.9	4.2	96.1	103.3	355.1
High Voltage Network > 1,000 kVA	10.8	29.9	3.3	10.3	2.7	57.1
High Voltage Network Total	**16.4**	**175.8**	**7.6**	**106.4**	**106.0**	**412.2**
Low Voltage Network	9.7	156.1	1.5	42.1	17.0	226.5
Transformers	5.8	57.9	1.5	27.2	18.3	110.6
Streetlight Assets						23.3
Metering						69.7
Administration						139.6
Reference Service Revenue						**981.9**
Non-reference Service Revenue						**0.0**
Total Revenue Cap Service Revenue						**981.9**

Table 9 - Distribution Reference Service Customer Groups for 2012/13 ($M Nominal annualised)

								High Voltage Network		Low Voltage Network		Transformers	Streetlight Assets	Metering	Administration
Customer Group	ATMD MVA	GWh	Loss Adjusted ATMD's	Transformer Adjusted ATMD's	LV Adjusted ATMD's	Number of Customers	LV Adjusted Customer Numbers	Fixed $/annum	Variable $/annum	Fixed $/annum	Variable $/annum	Variable $/annum	Fixed		
Unmetereds	5	34	6	6	6	15,801	15,801	1.4	0.3	1.0	0.2	0.1	0.0	0.0	0.4
Streetlights	30	122	33	33	3	240,095	24,010	2.6	1.6	1.5	0.1	0.7	23.3	0.0	1.2
Residential	2,246	5,533	2,434	2,434	2,434	953,160	953,160	92.9	116.8	58.7	95.4	53.8	0.0	49.4	75.9
Small Business	519	1,401	543	543	543	88,523	88,523	14.4	32.1	5.5	21.6	13.4	0.0	11.2	15.1
General Business - Small	511	1,150	535	535	535	12,563	12,563	1.6	30.3	0.8	21.4	13.1	0.0	3.5	13.6
General Business - Medium	443	964	463	463	417	2,615	2,354	0.3	23.3	0.2	16.8	10.8	0.0	1.9	11.6
General Business - Large	512	1,190	529	529	53	1,017	102	0.1	25.1	0.0	2.1	11.9	0.0	1.3	13.3
LV greater than 1000kVA	268	513	277	277	28	196	20	3.5	18.0	0.0	1.1	6.6	0.0	0.4	2.4
HV less than 1000kVA	58	196	60	0	0	136	0	0.0	2.7	0.0	0.0	0.0	0.0	0.5	1.5
HV>1000	848	3,298	780	0	0	383	0	15.3	29.8	0.0	0.0	0.0	0.0	1.5	4.5
TOTAL	**5,441**	**14,402**	**5,659**	**4,819**	**4,018**	**1,314,490**	**1,096,532**	**132.2**	**280.0**	**67.7**	**158.8**	**110.6**	**23.3**	**69.7**	**139.6**

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 10 - 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

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 – Anytime Energy (Residential)

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.

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

5.2.2 RT2 – Anytime Energy (Business)

The tariff structure for distribution includes:

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

The tariff structure for transmission includes:

- A charge per kWh for metered energy consumption.

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

5.2.3 RT3 – Time of Use Energy (Residential)

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.

5.2.4 RT4 – Time of Use Energy (Business)

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.

5.2.5 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. There is a separate metering charge that picks up the capital and operating costs for the metering asset.

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 50% for off peak energy usage only and for an equal use of on and off peak energy the discount is 25%.

5.2.6 RT6 – Low Voltage Metered Demand

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

5.2.7 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 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 that 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.

5.2.8 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.

5.2.9 RT9 – Streetlighting

Streetlights 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.

In addition there is a charge to reflect the capital and operating costs of the streetlight asset itself. Western Power owns the assets and the revenue is included within the reference service revenue. The tariff structure for the streetlight asset is simply a fixed charge per light based on the type and rating of the light.

5.2.10 RT10 – Unmetered Supplies

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. However there is a requirement for the user to provide sufficient load data so that the energy consumption can be calculated. As such the available information is user connection and energy consumption.

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.

5.2.11 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 $ 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 $ 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 $ 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.

5.4 Bi-directional Service Tariff Overview

An overview of the structure of each of the reference tariffs applicable to bi-directional services is presented in the following sections. For all four bi-directional services, the tariffs are equivalent to the reference service upon which it is based as detailed in section 1.2.2.

5.4.1 RT13 – RT16

The tariff structure of these tariffs is based on the structures of tariffs RT1-4 detailed in sections 5.2.1 to 5.2.4.

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 Gross Optimised Deprival Value (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 the principles to apply in determining the sample of operating conditions considered.

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 as are as follows:

- Load and generation conditions shall be actual operating conditions from the previous 12 months; 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 $/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 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 UOS prices to give the required Use Of System cost pool revenues.

6.2.2 Connection Price

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

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.

6.2.3 Use of System (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. However, 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 demand 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 $/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 TUOS prices are therefore scaled and moderated as follows:

- annual changes to be constrained within a bandwidth of ± 5%; and
- the mid point of the band set to recover the required cost pool revenue.

6.2.3.3. UOS Prices – Exit Points

UOS prices for Exit Points are calculated within the constraints of the UOS Price Moderation specified above to recover the UOS for Loads Cost Pool Revenue.

6.2.3.4. UOS Prices – Entry Points

UOS prices for Entry Points are calculated within the constraints of the UOS Price Moderation specified above to recover the UOS for Generators Cost Pool Revenue.

6.2.4 Common Service Price for Loads

The Common Service Price is expressed in c/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 c/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 11 - Transmission Revenue Forecast for 2012/13 ($M Nominal annualised)

	Forecast Total MW	**Number Customers**	**Forecast Transmission Revenue Recovered**
Transmission Exit	613	26	32.6
Transmission Entry (includes LV Gens etc.)	6354	29	67.0
Distribution Users (Pass Through)	3977	1,314,511	323.0
Transmission Standby			0.5
Total Revenue Cap Revenue			**423.1**
Forecast under/over-recovery			0

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 revenues from these users are 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 can be illustrated in the following flow diagram.

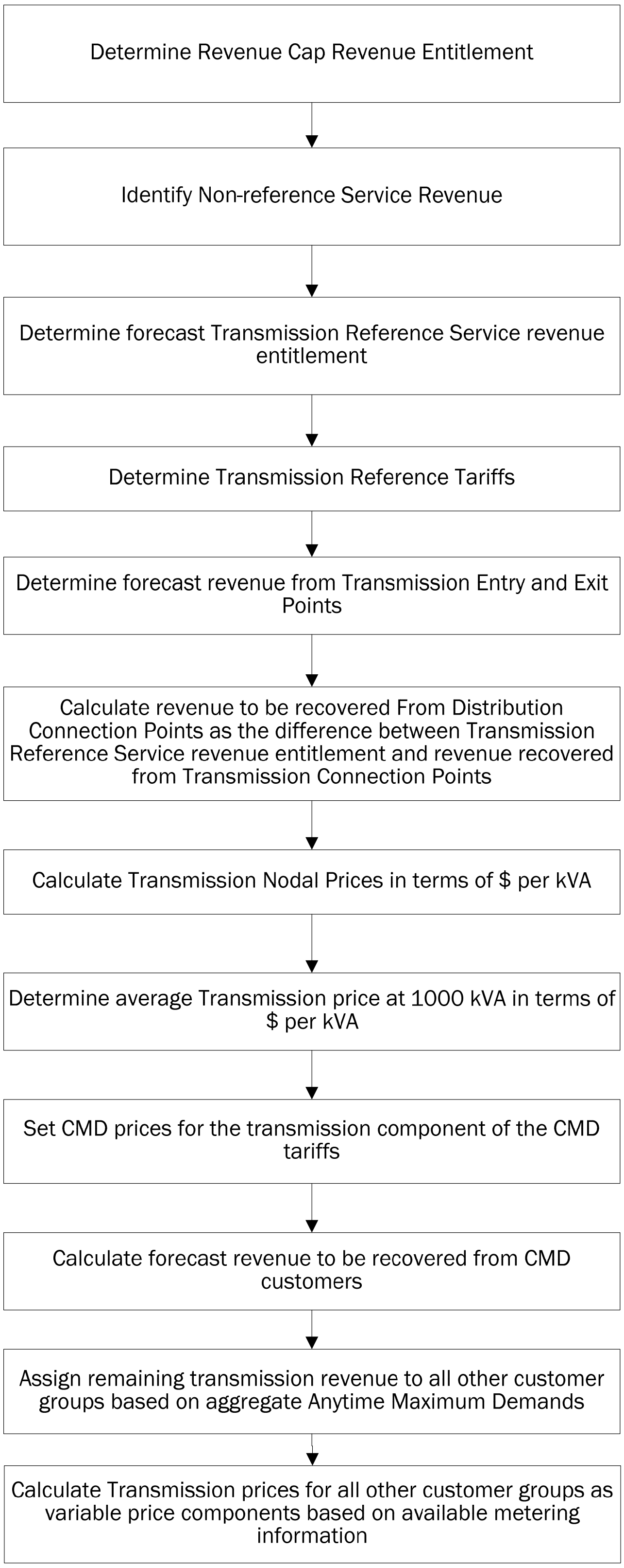

Figure 3 - Derivation of Transmission Tariff Component of Distribution System Flow Chart

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.

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

It is assumed at this stage 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 calculated the transmission prices in terms of $ 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 $/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 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 unknowns 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:

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

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

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

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

So we now have 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. We now have a single unknown ($\text{Price}_{\text{At } 1,000}$) that can now be solved in the above equation which now must be expanded as below.

Original Equation:

$$\text{RP}_{\text{Below } 1,000} = \text{RP}_{\text{Total}} – \text{RP}_{\text{Over } 7,000} - \text{RP}_{1,000 \text{ to } 7,000}$$

Expansion of each term:

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

RP_{Total} = Total transmission revenue entitlement allocated to distribution-connected users

$\text{RP}_{\text{Over } 7,000}$ = ∑ 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

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

At this stage of the process we have 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. 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

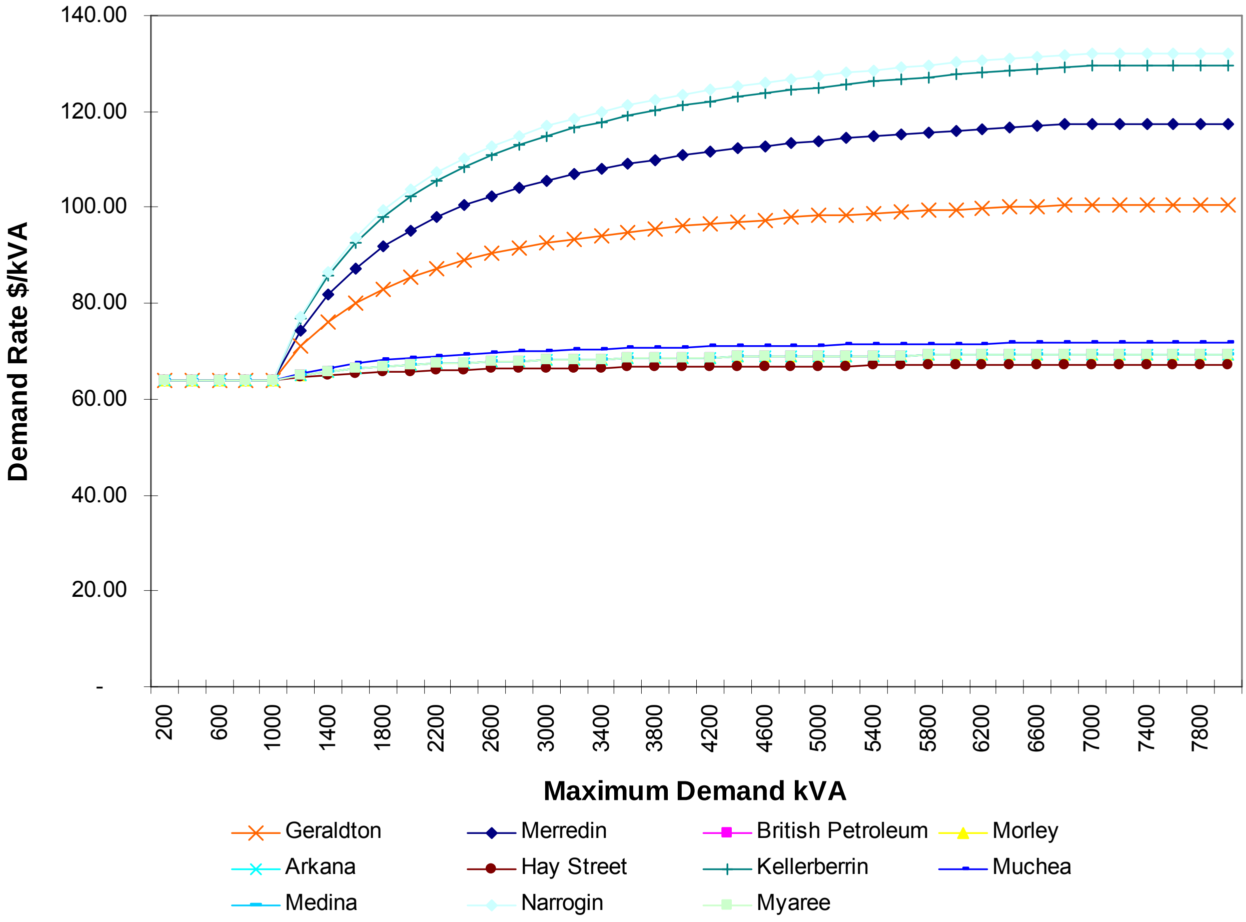

Figure 4 - Rate Blocks Example (DM 9954170)

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 - 1,000 kVA MD)
- General Business Medium (100 - 300 kVA MD)
- General Business Small (15 - 100 kVA MD)
- Small Business (<15 kVA MD)
- 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. We then have revenue entitlements assigned to reference tariffs. The process then becomes one of matching the revenue entitlement to metered information to produce tariff components.

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 simple 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.

In fact 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 clearly recovers most of the cost from on-peak usage which is the main driver of transmission costs;
- It allows for some of the costs to be recovered from off-peak energy usage to provide for equity between users with different load patterns; and
- It provides a clear 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 12 - Transmission Reference Service Revenue Recovered from Distribution Connection Points for 2012/13 ($M Nominal annualised)

	kWh	ATMD kVA	Number Customers	Forecast Transmission Revenue Recovered
RT1 - Anytime Energy (Residential)	5,319,275,949	2,158,583	928,361	115.6
RT2 - Anytime Energy (Business)	1,626,702,520	653,210	90,014	40.7
RT3 - Time of Use Energy (Residential)	213,268,785	87,672	24,799	5.6
RT4 - Time of Use Energy (Business)	2,009,149,700	1,085,581	12,687	48.2
RT5 - High Voltage Metered Demand	405,345,690	127,012	184	8.5
RT6 - Low Voltage Metered Demand	1,343,018,790	435,862	2,130	32.4
RT7 - High Voltage Contract Maximum Demand	3,089,046,010	769,256	335	63.4
RT8 - Low Voltage Contract Maximum Demand	239,760,628	77,629	84	6.7
RT9 – Streetlighting	121,595,204	30,107	240,095	1.7
RT10 - Unmetered Supplies	34,479,656	5,480	15,801	0.3
RT11 - Distribution Entry	0	0	21	0.0
RT13 – Anytime Energy (Residential) Bi-directional	0	0	0	0
RT14 – Anytime Energy (Business) Bi-directional	0	0	0	0
RT15 – Time of Use (Residential) Bi-directional	0	0	0	0
RT16 – Time of Use (Business) Bi-directional	0	0	0	0
TOTAL	**14,401,642,932**	**5,430,391**	**1,314,511**	**323.0**

6.4 Annual Price Review

As described in the Access Arrangement, the reference 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.

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 needs to 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 as rigorous a process as is possible taking into account the information available and the requirements of the Code.

The distribution reference tariff components include the costs associated with the Tariff Equalisation Contribution (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 7.5 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 13 - Distribution Reference Tariff Components

TARIFF	TARIFF COMPONENTS									
	Fixed Component	Energy Only	On Peak Energy	Off Peak Energy	Annual Metered Demand	Off Peak Discount Factor (%)	CMD/DSOC	Demand/ Length for ATMD > 1,000 kVA	Fixed Metering Component	Variable Metering Component
RT1 - Energy Only (Residential)	✓	✓							✓	✓
RT2 - Energy Only (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	✓	✓								
RT11 - Distribution Entry							✓	✓	✓	
RT13 – Energy only (Residential) Bi-directional	✓	✓							✓	✓
RT14 – Energy only (Business) Bi-directional	✓	✓							✓	✓
RT15 – Time of Use (Residential) Bi-directional	✓		✓	✓					✓	✓
RT16 – Time of Use (Business) Bi-directional	✓		✓	✓					✓	✓

7.1.2 RT1 and RT2 - Energy Only Tariff (Residential or Business)

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 TOU 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.

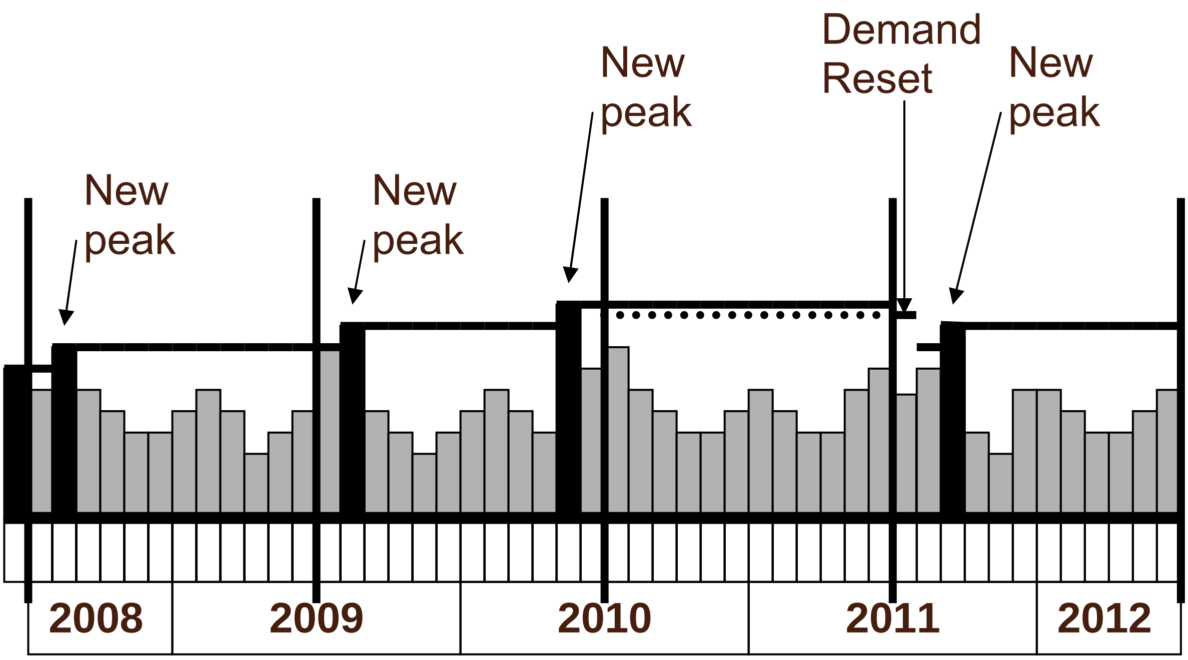

Figure 5 - Rolling Peak Illustration

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" component of the tariff ameliorates this distortion because it recognises that the cost of supply of a user does not only relate to the distance from the zone substation but also relates to the demand that the user places on the network.

The effect of the pricing structure is that, 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 only 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.

At this stage we have the distribution nodal prices at 7,000 kVA. We also have established that 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 task 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 unknowns 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:

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

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

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

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

So we now have 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.

We now have a single unknown (Price At 1,000) that can now be solved in the above equation which now must 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 $_{Below\ 1,000}$ = ∑ User anytime maximum demands multiplied by Price At 1,000

RP $_{Total}$ = Total HV network revenue entitlement

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

At this stage of the process we have 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. 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 also 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 $_{1,000\ to\ 7,000}$ = [(Price $_{At\ 7,000}$ * 7,000 kVA) - (Price $_{At\ 1,000}$ * 1,000 kVA)]/6,000 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 zone and the price settings are adjusted so that 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

The ideal way to price metering is to have a separate charge for the particular type of meter for each user. While this approach is technically feasible, it is extremely complex due to the technical and commercial variations in metering arrangements.

The alternative and more efficient approach is to use a standard metering charge in conjunction with each reference tariff to reflect the average cost of metering deployed to support application of the tariff.

However, the variation in metering costs for users within each tariff group can be marked and an average metering charge would disadvantage all smaller users. For example:

- residential users may be either single or three phase; and
- small business users with energy only or TOU energy metering may have meters direct- or CT-connected.

Therefore, it is appropriate for small users to have a charge that varies with usage and therefore approximates the variation in metering costs.

The metering price structure is as follows:

Reference Tariff Type	Metering Price
Energy	Cents/kWh and $ fixed annual charge
TOU Energy	Cents/kWh and $ fixed annual charge
Metered Demand	$ fixed annual charge
CMD/DSOC	$ fixed annual charge

7.1.7 Administration

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

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 that 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.

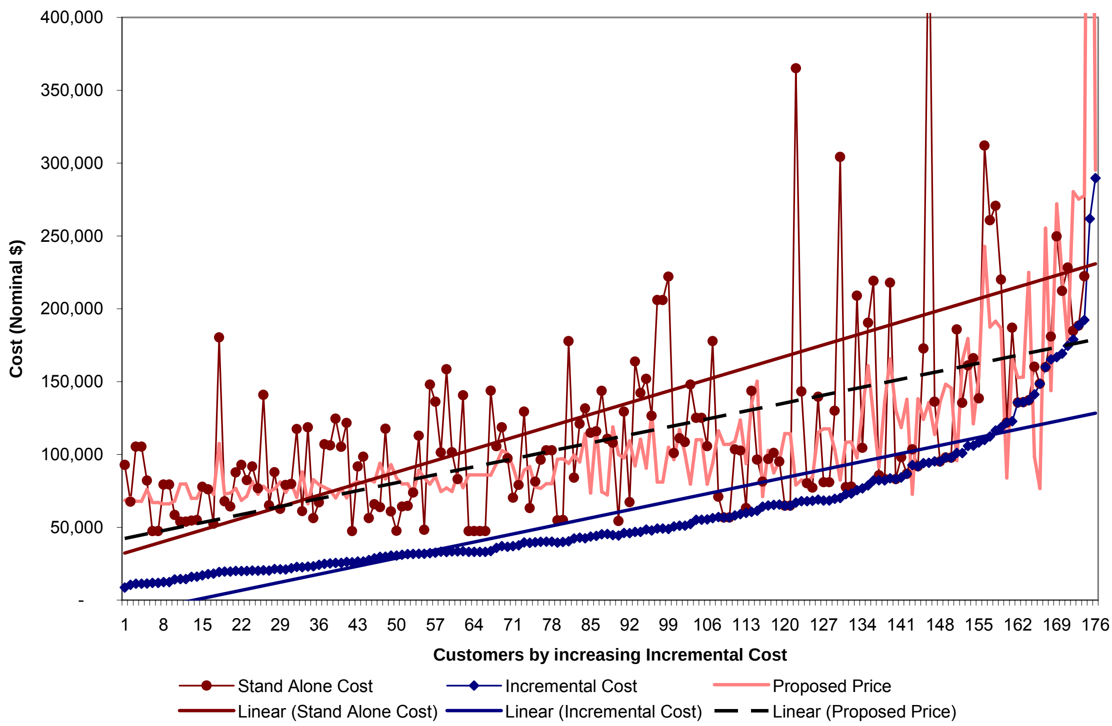

Figure 6 - Urban Zone (DM 9954170)

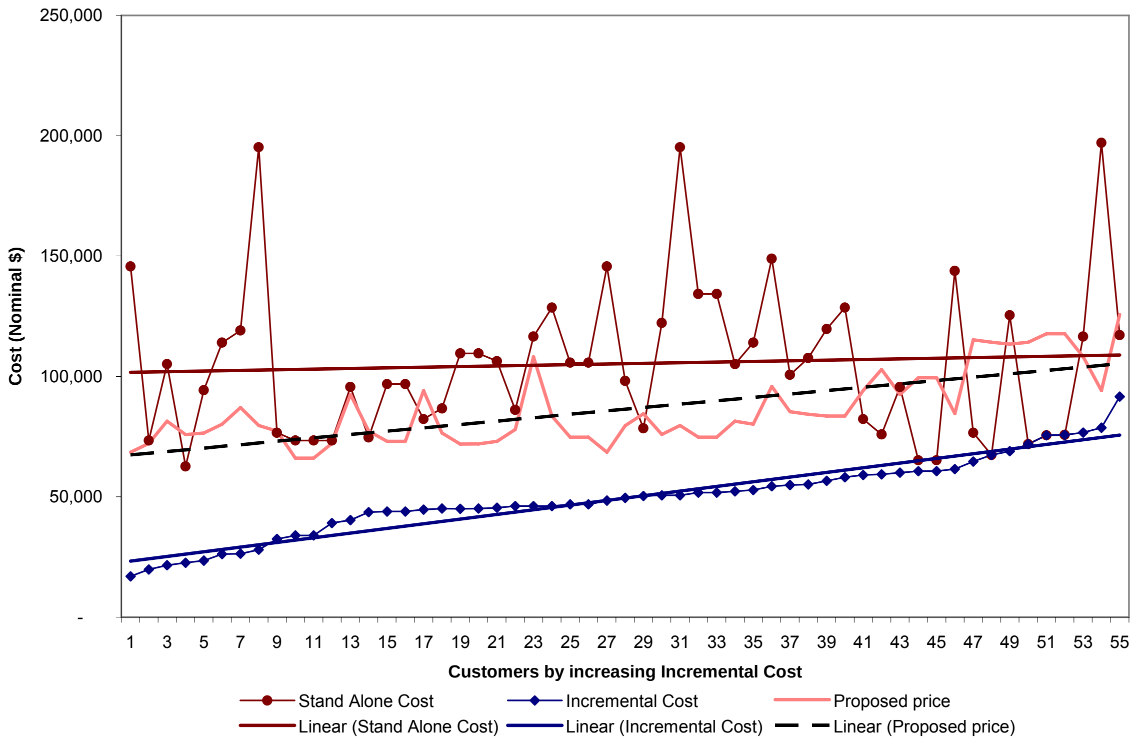

Figure 7 - CBD Zone (DM 9954170)

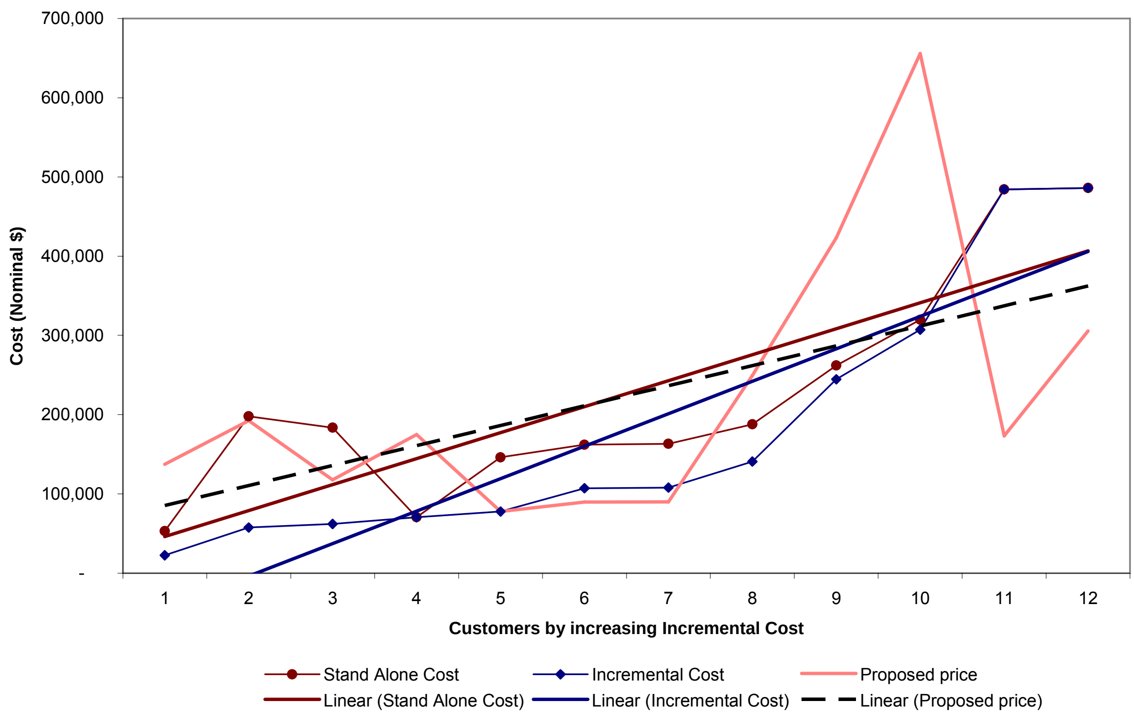

Figure 8 - Mining Zone (DM 9954170)

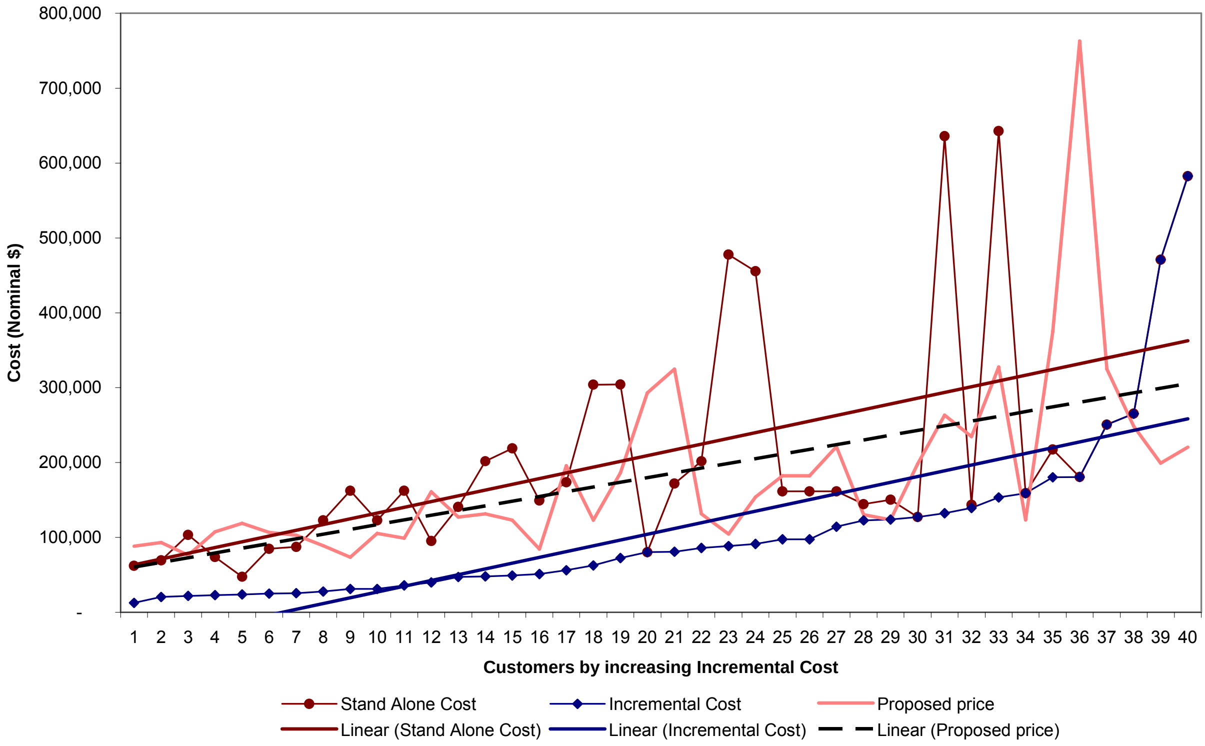

Figure 9 - Mixed Zone (DM 9954170)

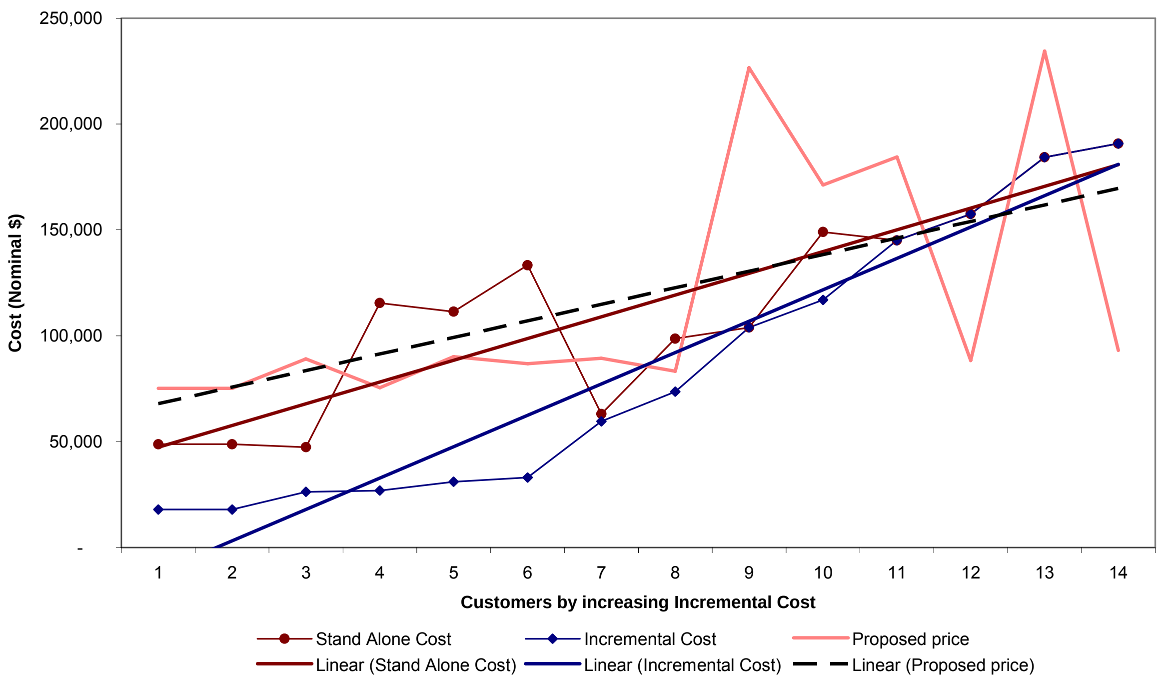

Figure 10 - Rural Zone (DM 9954170)

7.2.2 Demand/Length Graph

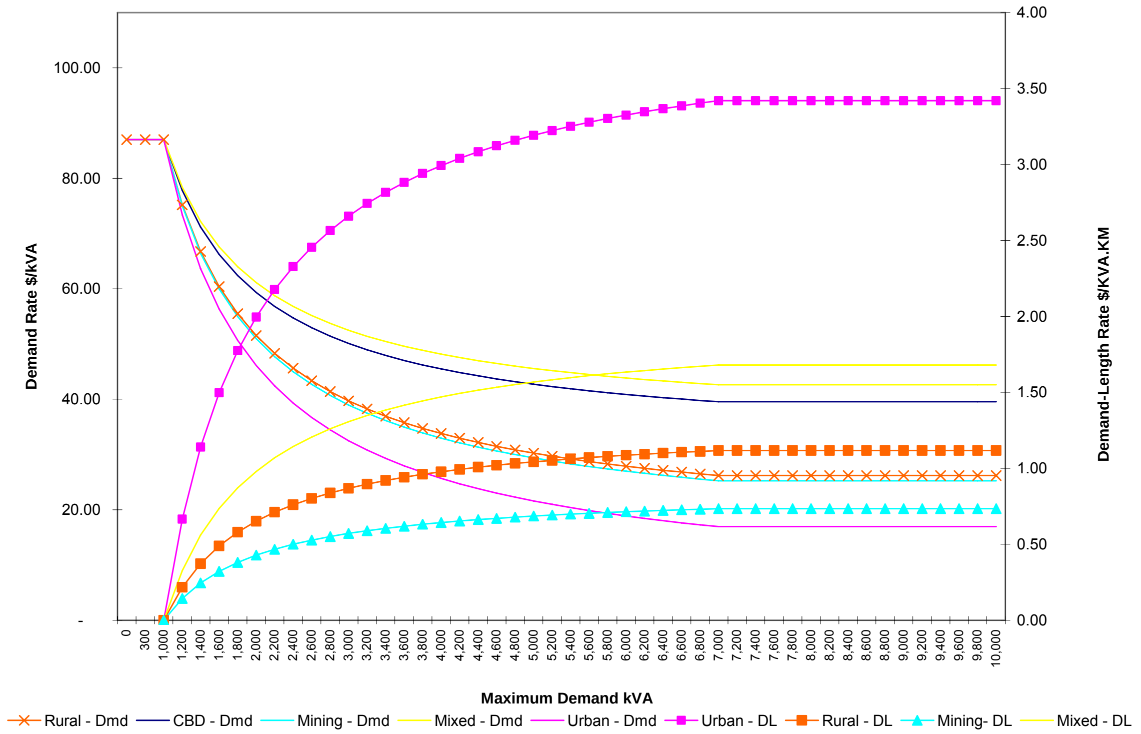

Figure 11 - Demand Length Rates and CMD Rates by Zone (DM 9954170)

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 14 - Distribution Reference Service Revenue Recovered from Distribution Connection Points for 2012/13 ($M Nominal annualised)

	kWh	ATMD kVA	Number Customers	Forecast Distribution Revenue Recovered
RT1 - Anytime Energy (Residential)	5,319,275,949	2,158,583	928,361	513.8
RT2 - Anytime Energy (Business)	1,626,702,520	653,210	90,014	157.2
RT3 - Time of Use Energy (Residential)	213,268,785	87,672	24,799	20.1
RT4 - Time of Use Energy (Business)	2,009,149,700	1,085,581	12,687	123.0
RT5 - High Voltage Metered Demand	405,345,690	127,012	184	13.7
RT6 - Low Voltage Metered Demand	1,343,018,790	435,862	2,130	62.3
RT7 - High Voltage Contract Maximum Demand	3,089,046,010	769,256	335	46.2
RT8 - Low Voltage Contract Maximum Demand	239,760,628	77,629	84	10.6
RT9 – Streetlighting	121,595,204	30,107	240,095	31.2
RT10 - Unmetered Supplies	34,479,656	5,480	15,801	3.2
RT11 - Distribution Entry	0	0	20	0.7
RT13 – Anytime Energy (Residential) Bi-directional	0	0	0	0
RT14 – Anytime Energy (Business) Bi-directional	0	0	0	0
RT15 – Time of Use (Residential) Bi-directional	0	0	0	0
RT16 – Time of Use (Business) Bi-directional	0	0	0	0
TOTAL	**14,401,642,932**	**5,430,391**	**1,314,510**	**981.9**
Forecast over/(under)-recovery				**0.0**

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

In accordance with section 7.3(b) (i) and (ii) 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 2012/13.

Table 15 - Demonstration that Reference Tariffs are between incremental and stand-alone cost of service provision for 2012/13 ($M Nominal annualised)

Reference Service	Reference Tariff	Incremental Cost of Service	Stand-alone Cost of Service Provision	Forecast Revenue Recovered from Reference Tariff
A1	RT1	417.8	619.4	553.1
A2	RT2	124.4	324.7	174.5
A3	RT3	16.1	216	22.6
A4	RT4	139.7	374.8	141.2
A5	RT5	14.1	205.2	17.2
A6	RT6	59.5	259.5	76.9
A7	RT7	95.1	109.3	104.3
A8	RT8	13.2	16.3	15.4
A9	RT9	28	227.9	32.2
A10	RT10	1.2	224.4	3.3
C1	RT13	0	0	0
C2	RT14	0	0	0
C3	RT15	0	0	0
C4	RT16	0	0	0

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

The values in Table 15 are derived during the cost of supply modelling process. Each service is allocated a combination of fixed and variable cost pools calculated as per this document. Table 16 demonstrates the allocations made.

Table 16 – cost pools used to determine incremental and stand-alone cost

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

7.3.2 Material changes since 2011/12

Following a review of the methodology for determining stand-alone and incremental costs described in section 7.3.1, two material changes have been made.

The first relates to the treatment of TEC. Previously, TEC was included both as an incremental and stand-alone cost, but as it is not a network cost it is now excluded from the determination of incremental and stand-alone costs.

The second change relates to the allocation of transmission costs. Western Power uses the industry standard program T-price to produce the transmission prices that apply at each transmission node. Each price is in the form of a $/kW rate only; that is, the price is purely variable and has no fixed component. This approach is carried through to the transmission component of the bundled tariffs that apply to distribution connected customers as purely variable price components. Western Power's cost of supply model therefore only allocates transmission costs to variable cost pools. However, the reality is that there is a mix of both fixed and variable costs incurred in the provision of transmission network services.

Under the method described in section 7.3.1, with zero fixed costs, the transmission component of both incremental and stand-alone costs is effectively the same.

To correct this, the transmission cost pool for each tariff has now been split into fixed and variable costs for the (sole) purpose of allocating costs in the incremental cost model. To derive a split between fixed and variable transmission costs Western Power has used an approach that recognises that fixed costs largely relate to capital already invested in the network. The calculation uses the proportion of total transmission revenue related to the sum of the approved 'return on' and 'return of' assets amounts[3] as a reasonable estimate of fixed costs. This approach leads to an approximate split of 60% fixed costs to 40% variable costs for transmission.

To support the validity of this approach, when it is applied to distribution, it results in the same 40% fixed to 60% variable split used in the distribution cost allocation model and as calculated in section 4.4.7.

During the investigations that led to the above changes, other minor corrections were made to the model. Due to these changes, the figures published in the 2011/12 Price List Information were slightly (but not materially[4]) incorrect. Therefore direct comparison between this table and 2011/12 is difficult, as highlighted by the Authority's draft decision.

7.4 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.

[3] As determined in the revenue model.

[4] While there were small changes to most of the figures used, the most significant difference was the stand-alone cost reported for A6 – the correct figure should have been $234m (instead of the $335m published).

7.5 Tariff Equalisation Contribution (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.

Note: the TEC requirement has been treated similarly to the 2012/13 revenue requirement. The TEC as gazetted on 7 August 2012 is $154 million in 2012/13; however the TEC components in tariffs from the beginning of 2012/13 would only have recovered approximately $147 million (if applied for the whole year), so therefore the TEC components to apply from 1 February have been adjusted upwards to recover the total TEC requirement in 2012/13. For the purpose of setting tariffs in the period 1 February to 30 June 2013, the annual TEC requirement has been adjusted to $163.5 million.

7.5.1 TEC Forecast Revenue

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

Table 17 - TEC Recovered from Distribution Connection Points for 2012/13 ($M Nominal annualised)

	kWh	ATMD kVA	Number Customers	Forecast TEC Recovered
RT1 - Anytime Energy (Residential)	5,319,275,949	2,158,583	928,361	76.3
RT2 - Anytime Energy (Business)	1,626,702,520	653,210	90,014	23.3
RT3 - Time of Use Energy (Residential)	213,268,785	87,672	24,799	3.1
RT4 - Time of Use Energy (Business)	2,009,149,700	1,085,581	12,687	30.0
RT5 - High Voltage Metered Demand	405,345,690	127,012	184	4.9
RT6 - Low Voltage Metered Demand	1,343,018,790	435,862	2,130	17.8
RT7 - High Voltage Contract Maximum Demand	3,089,046,010	769,256	335	5.2
RT8 - Low Voltage Contract Maximum Demand	239,760,628	77,629	84	1.9
RT9 – Streetlighting	121,595,204	30,107	240,095	0.7
RT10 - Unmetered Supplies	34,479,656	5,480	15,801	0.2
RT11 - Distribution Entry	0	0	21	0.0
RT13 – Anytime Energy (Residential) Bi-directional	0	0	0	0
RT14 – Anytime Energy (Business) Bi-directional	0	0	0	0
RT15 – Time of Use (Residential) Bi-directional	0	0	0	0
RT16 – Time of Use (Business) Bi-directional	0	0	0	0
TOTAL	**14,401,642,932**	**5,430,391**	**1,314,511**	**163.5**

7.5.2 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 18

	Fixed TEC	Variable TEC		
	c/day	c/kWh	On Peak c/kWh	Off Peak c/kWh
Reference tariff 1 - RT1				
TEC	0.000	1.435	-	-
Reference tariff 2 - RT2				
TEC	0.000	1.435	-	-
Reference tariff 3 - RT3				
TEC	0.000	-	2.043	0.584
Reference tariff 4 - RT4				
TEC	0.000	-	2.036	0.582
Reference tariff 9 – RT9				
TEC	0.000	0.581	-	-
Reference tariff 10 – RT10				
TEC	0.000	0.564	-	-

7.5.3 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 19

	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	0.000	13.568	0.000	13.568
300 to 1000	4,070.400	13.088	4,070.400	13.088
1000 to 1500	13,232.000	4.761	13,232.000	4.761

7.5.4 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 20

Pricing Zone	RT 7 and 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	5,753.425	-0.959	0.000
Goldfields Mining	5,753.425	-0.959	0.000
Mixed	5,753.425	-0.959	0.000
Rural	5,753.425	-0.959	0.000
Urban	5,753.425	-0.959	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.

7.5.5 TEC Tariff Components – LV prices

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

Table 21

	Fixed	Demand (c/day)
LV Prices	0.00	0.822/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.

For distribution tariff revenues:

$$\frac{\sum_{y=1}^{n} p_{2012/13}^{xy} q_{2012/13}^{xy}}{\sum_{y=1}^{n} p_{2011/12}^{xy} q_{2012/13}^{xy}} \le (1+CPI_{2012/13})(1-DX_{2012/13}) + A'_{2012/13} + 0.02$$

where:

$$A'_t = \frac{DK_t + DAA2_t + \Delta TEC_t}{DR'_t}$$

For transmission tariff revenues:

$$\frac{\sum_{y=1}^{n} p_{2012/13}^{xy} q_{2012/13}^{xy}}{\sum_{y=1}^{n} p_{2011/12}^{xy} q_{2012/13}^{xy}} \le (1+CPI_{2012/13})(1-TX_{2012/13}) + B'_{2012/13} + 0.02$$

where:

$$B'_t = \frac{TK_t + TAA2_t}{TR'_t}$$

The following values have been used to calculate the right hand side of each side constraint in 2012/13:

Table 22

Variable	Value	Variable	Value
CPI_t	2.25%	$DAA2_t$	0
DX_t	1.79%	$TAA2_t$	0
TX_t	6.72%	ΔTEC_t	($27.20m)
TK_t	$27.08m	TR'_t	$395.98m
DK_t	$50.21m	DR'_t	$701.16m
A'_t	3.28%	B'_t	6.84%

Side constraint values:

Table 23

Distribution	Constraint	Transmission	Constraint
$(1+CPI_t)(1-DX_t)+A'_t+0.02$	5.70%	$(1+CPI_t)(1-TX_t)+B'_t+0.02$	4.22%

Table 24 demonstrates compliance with these constraints on all tariffs.

Table 24

	Change in weighted average revenue		Constraint compliance	
Tariff	Distribution	Transmission	Distribution	Transmission
RT1	5.67%	3.14%	✓	✓
RT2	4.66%	1.25%	✓	✓
RT3	4.89%	0.83%	✓	✓
RT4	5.70%	3.33%	✓	✓
RT5	4.45%	0.95%	✓	✓
RT6	5.60%	0.95%	✓	✓
RT7	4.22%	0.07%	✓	✓
RT8	5.42%	-0.37%	✓	✓
RT9	3.33%	-5.10%	✓	✓
RT10	5.64%	-4.90%	✓	✓
RT11	3.33%	-5.57%	✓	✓
RT13	*	*	N/A	N/A
RT14	*	*	N/A	N/A
RT15	*	*	N/A	N/A
RT16	*	*	N/A	N/A
TRT1	N/A	-0.39%	N/A	✓
TRT2	N/A	-5.57%	N/A	✓

*Not applicable as this is the first year the tariff will apply.

8.2 Re-balancing of tariffs

As discussed in section 1.2.3, during AA2, rather than adjusting individual tariffs by different amounts, the decision was made (in order to reduce price shock to individual customer groups) to increase all network tariffs by the same amount each year. What this has meant is that some prices that applied during 11/12 had deviated slightly from their "optimal" level as determined by the pricing model. The intention during the AA3 period is to restore tariffs to the appropriate level by performing some minor re-balancing between tariffs as allowed by the side constraints.

As can be seen from Table 24, the tariffs with the most significant variations from the average price movements are:

- RT9 and 10 - the transmission component of these tariffs has been raised too high as a result of the cumulative effects of the previous scaled price increases. They are now being reduced to restore them to more cost reflective levels. It is worth noting, the transmission component of these tariffs is very small.

- TRT2 – cumulative effects of previous annual scaled price increases now requires a reduction to cost reflective levels.

8.3 Individual component changes

The following tables detail the % change in the 2012/13 tariff components when compared to the 2011/12 tariff components.

8.3.1 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 25

		Fixed Price	Energy Rates		
		% Change	Anytime % Change	On Peak % Change	Off Peak % Change
Reference tariff 1 - RT1					
	Transmission		7.52%		
	Distribution	19.31%	23.79%		
	Bundled Tariff	19.31%	19.00%		
	Metering	-44.47%	-29.46%		
Reference tariff 2 – RT2					
	Transmission		3.00%		
	Distribution	67.26%	12.10%		
	Bundled Tariff	67.26%	9.71%		
	Metering	-44.47%	-29.46%		
Reference tariff 3 - RT3					
	Transmission			2.00%	2.00%
	Distribution	26.40%		23.97%	23.39%
	Bundled Tariff	26.40%		16.78%	16.85%
	Metering	-44.47%		-45.55%	-45.55%
Reference tariff 4 - RT4					
	Transmission			8.00%	8.00%
	Distribution	19.72%		15.24%	15.22%
	Bundled Tariff	19.72%		13.03%	12.94%
	Metering	-44.53%		-18.47%	-18.47%
Reference tariff 9 – RT9					
	Transmission		-12.25%		
	Distribution	26.10%	-18.84%		
	Bundled Tariff	26.10%	-16.88%		
Reference tariff 10 – RT10					
	Transmission		-11.77%		
	Distribution	68.47%	-31.51%		
	Bundled Tariff	68.47%	-27.86%		
Reference tariff 13 – RT13					
	Transmission	-	-		
	Distribution	-	-		
	Bundled Tariff	-	-		
	Metering	-	-		
Reference tariff 14 – RT14					
	Transmission	-	-		
	Distribution	-	-		
	Bundled Tariff	-	-		
	Metering	-	-		

Reference tariff 15 – RT15					
	Transmission	-		-	-
	Distribution	-		-	-
	Bundled Tariff	-		-	-
	Metering	-		-	-
Reference tariff 16 – RT16					
	Transmission	-		-	-
	Distribution	-		-	-
	Bundled Tariff	-		-	-
	Metering	-		-	-

8.3.2 Streetlight Asset Prices

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

Table 26

Light Specification	Annual Charge % Change
42W CFL SE	11.3%
42W CFL BH	11.3%
42W CFL KN	11.3%
70W MH	11.3%
70W HPS	11.3%
125W MV	11.3%
150W MH	11.3%
150W HPS	11.3%
250W MH	11.3%
250W HPS	11.3%

Table 27

Light Specification	Annual Charge % Change
50W MV	11.3%
60W MV	11.3%
70W MV	11.3%
80W MV	11.3%
150W MV	11.3%
250W MV	11.3%
400W MV	11.3%
40W FLU	11.3%
80W HPS	11.3%
125W HPS	11.3%
60W INC	11.3%
100W INC	11.3%
80W MH	11.3%
125W MH	11.3%
250W LPS	11.3%

8.3.3 Metered Demand Prices

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

Table 28

	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		2.28%	21.3%	14.5%	21.3%	9.3%
300 to 1000	2.28%	2.28%	14.5%	12.6%	9.3%	8.2%
1000 to 1500	2.28%	2.28%	13.3%	13.7%	8.6%	8.0%

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

Table 29

	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		2.28%	20.3%	14.6%	20.3%	9.7%
300 to 1000	2.28%	2.28%	14.9%	13.3%	10.1%	9.1%
1000 to 1500	2.28%	2.28%	13.9%	15.1%	9.4%	9.7%

8.3.4 Demand Prices

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

Table 30

			Transmission			Distribution			Bundled		
Zone Substation	TNI	Pricing Zone	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)	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)	Fixed charge for first 1000 kVA (c per day)	Demand charge for 1000<kVA<7000 (c/kVA/day)	Demand Charge for kVA > 7000 (c/kVA/day)
Cook Street	WCKT	CBD	-1.20%	0.79%	0.52%	10.6%	17.6%	15.3%	5.3%	5.6%	5.5%
Forrest Avenue	WFRT	CBD	-1.20%	0.79%	0.52%	10.6%	17.6%	15.3%	5.3%	5.6%	5.5%
Hay Street	WHAY	CBD	-1.20%	0.79%	0.52%	10.6%	17.6%	15.3%	5.3%	5.6%	5.5%
Milligan Street	WMIL	CBD	-1.20%	0.79%	0.52%	10.6%	17.6%	15.3%	5.3%	5.6%	5.5%
Wellington Street	WWNT	CBD	-1.20%	0.79%	0.52%	10.6%	17.6%	15.3%	5.3%	5.6%	5.5%
Black Flag	WBKF	Goldfields Mining	-1.20%	5.23%	4.73%	10.6%	10.0%	10.3%	5.3%	5.7%	5.6%
Boulder	WBLD	Goldfields Mining	-1.20%	2.50%	2.20%	10.6%	10.0%	10.3%	5.3%	3.2%	3.6%
Bounty	WBNY	Goldfields Mining	-1.20%	1.02%	0.92%	10.6%	10.0%	10.3%	5.3%	1.5%	1.8%
West Kalgoorlie	WWKT	Goldfields Mining	-1.20%	4.23%	3.75%	10.6%	10.0%	10.3%	5.3%	4.9%	4.9%

Zone Substation	TNI	Pricing Zone	Transmission			Distribution			Bundled		
			Fixed charge for first 1000 kVA (c per day)	Demand charge for 1000<kVA<7000 (c/kVA/day)	Demand Charge for kVA > 7000 (c/kVA/day)	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)	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)
Albany	WALB	Mixed	-1.20%	0.04%	-0.06%	10.6%	17.4%	15.3%	5.3%	3.6%	3.8%
Boddington	WBOD	Mixed	-1.20%	1.89%	1.42%	10.6%	17.4%	15.3%	5.3%	7.0%	6.6%
Bunbury Harbour	WBUH	Mixed	-1.20%	1.90%	1.44%	10.6%	17.4%	15.3%	5.3%	7.0%	6.6%
Busselton	WBSN	Mixed	-1.20%	-1.04%	-1.06%	10.6%	17.4%	15.3%	5.3%	3.1%	3.4%
Byford	WBYF	Mixed	-1.20%	2.19%	1.70%	10.6%	17.4%	15.3%	5.3%	7.0%	6.7%
Capel	WCAP	Mixed	-1.20%	-0.70%	-0.76%	10.6%	17.4%	15.3%	5.3%	4.0%	4.2%
Chapman	WCPN	Mixed	-1.20%	-1.16%	-1.16%	10.6%	17.4%	15.3%	5.3%	2.4%	2.8%
Darlington	WDTN	Mixed	-1.20%	2.65%	2.12%	10.6%	17.4%	15.3%	5.3%	7.1%	6.8%
Durlacher Street	WDUR	Mixed	-1.20%	-1.07%	-1.08%	10.6%	17.4%	15.3%	5.3%	2.9%	3.3%
Eneabba	WENB	Mixed	-1.20%	-1.05%	-1.06%	10.6%	17.4%	15.3%	5.3%	3.1%	3.4%
Geraldton	WGTN	Mixed	-1.20%	-1.07%	-1.08%	10.6%	17.4%	15.3%	5.3%	2.9%	3.3%
Marriott Road	WMRR	Mixed	-1.20%	-0.63%	-0.71%	10.6%	17.4%	15.3%	5.3%	5.3%	5.3%
Muchea	WMUC	Mixed	-1.20%	2.83%	2.30%	10.6%	17.4%	15.3%	5.3%	7.2%	6.8%
Northam	WNOR	Mixed	-1.20%	-1.04%	-1.06%	10.6%	17.4%	15.3%	5.3%	3.1%	3.5%
Picton	WPIC	Mixed	-1.20%	0.43%	0.21%	10.6%	17.4%	15.3%	5.3%	5.6%	5.5%
Rangeway	WRAN	Mixed	-1.20%	4.76%	4.22%	10.6%	17.4%	15.3%	5.3%	7.5%	7.2%
Sawyers Valley	WSVL	Mixed	-1.20%	-1.06%	-1.07%	10.6%	17.4%	15.3%	5.3%	3.0%	3.4%
Yanchep	WYCP	Mixed	-1.20%	-0.73%	-0.79%	10.6%	17.4%	15.3%	5.3%	4.8%	4.9%
Yilgarn	WYLN	Mixed	-1.20%	-1.09%	-1.10%	10.6%	17.4%	15.3%	5.3%	2.8%	3.2%
Baandee	WBDE	Rural	-1.20%	-1.29%	-1.28%	10.6%	10.0%	10.3%	5.3%	-0.3%	0.5%
Beenup	WBNP	Rural	-1.20%	5.61%	5.14%	10.6%	10.0%	10.3%	5.3%	6.0%	5.9%
Bridgetown	WBTN	Rural	-1.20%	3.72%	3.18%	10.6%	10.0%	10.3%	5.3%	4.6%	4.7%
Carrabin	WCAR	Rural	-1.20%	-1.34%	-1.34%	10.6%	10.0%	10.3%	5.3%	-0.4%	0.2%
Collie	WCOE	Rural	-1.20%	-1.15%	-1.16%	10.6%	10.0%	10.3%	5.3%	0.1%	1.0%
Coolup	WCLP	Rural	-1.20%	4.94%	4.43%	10.6%	10.0%	10.3%	5.3%	5.5%	5.5%
Cunderdin	WCUN	Rural	-1.20%	-1.25%	-1.25%	10.6%	10.0%	10.3%	5.3%	-0.1%	0.6%
Katanning	WKAT	Rural	-1.20%	-1.18%	-1.18%	10.6%	10.0%	10.3%	5.3%	0.1%	0.9%
Kellerberrin	WKEL	Rural	-1.20%	-1.28%	-1.27%	10.6%	10.0%	10.3%	5.3%	-0.2%	0.5%
Kojonup	WKOJ	Rural	-1.20%	2.87%	2.35%	10.6%	10.0%	10.3%	5.3%	4.0%	4.3%
Kondinin	WKDN	Rural	-1.20%	-0.99%	-1.01%	10.6%	10.0%	10.3%	5.3%	0.6%	1.5%
Manjimup	WMJP	Rural	-1.20%	3.68%	3.14%	10.6%	10.0%	10.3%	5.3%	4.6%	4.7%
Margaret River	WMRV	Rural	-1.20%	-1.27%	-1.26%	10.6%	10.0%	10.3%	5.3%	-0.2%	0.5%
Merredin	WMER	Rural	-1.20%	-1.23%	-1.22%	10.6%	10.0%	10.3%	5.3%	-0.1%	0.7%
Mirambeena	WMBN	Rural	-1.20%	-0.37%	-0.53%	10.6%	10.0%	10.3%	5.3%	2.1%	3.0%
Moora	WMOR	Rural	-1.20%	4.11%	3.58%	10.6%	10.0%	10.3%	5.3%	4.9%	5.0%
Mount Barker	WMBR	Rural	-1.20%	-1.05%	-1.06%	10.6%	10.0%	10.3%	5.3%	0.2%	1.0%
Narrogin	WNGN	Rural	-1.20%	-1.29%	-1.28%	10.6%	10.0%	10.3%	5.3%	-0.3%	0.5%
Pinjarra	WPNJ	Rural	-1.20%	-0.70%	-0.77%	10.6%	10.0%	10.3%	5.3%	1.2%	2.1%
Regans	WRGN	Rural	-1.20%	-1.06%	-1.07%	10.6%	10.0%	10.3%	5.3%	0.4%	1.3%
Three Springs	WTSG	Rural	-1.20%	-0.06%	-0.18%	10.6%	10.0%	10.3%	5.3%	1.3%	2.0%
Wagerup	WWGP	Rural	-1.20%	-0.70%	-0.78%	10.6%	10.0%	10.3%	5.3%	1.3%	2.3%
Wagin	WWAG	Rural	-1.20%	4.52%	4.00%	10.6%	10.0%	10.3%	5.3%	5.2%	5.2%

Zone Substation	TNI	Pricing Zone	Transmission			Distribution			Bundled		
			Fixed charge for first 1000 kVA (c per day)	Demand charge for 1000<kVA<7000 (c/kVA/day)	Demand Charge for kVA > 7000 (c/kVA/day)	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)	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)
Wundowie	WWUN	Rural	-1.20%	-0.57%	-0.62%	10.6%	10.0%	10.3%	5.3%	0.7%	1.4%
Yerbillon	WYER	Rural	-1.20%	-1.33%	-1.33%	10.6%	10.0%	10.3%	5.3%	-0.4%	0.3%
Amherst	WAMT	Urban	-1.20%	0.59%	0.35%	10.6%	9.5%	10.3%	5.3%	1.2%	2.2%
Arkana	WARK	Urban	-1.20%	0.59%	0.35%	10.6%	9.5%	10.3%	5.3%	1.2%	2.2%
Australian Paper Mills	WAPM	Urban	-1.20%	0.59%	0.35%	10.6%	9.5%	10.3%	5.3%	1.2%	2.2%
Beechboro	WBCH	Urban	-1.20%	0.59%	0.35%	10.6%	9.5%	10.3%	5.3%	1.2%	2.2%
Belmont	WBEL	Urban	-1.20%	0.59%	0.35%	10.6%	9.5%	10.3%	5.3%	1.2%	2.2%
Bentley	WBTY	Urban	-1.20%	0.59%	0.35%	10.6%	9.5%	10.3%	5.3%	1.2%	2.2%
Bibra Lake	WBIB	Urban	-1.20%	0.59%	0.35%	10.6%	9.5%	10.3%	5.3%	1.2%	2.2%
British Petroleum	WBPM	Urban	-1.20%	0.59%	0.35%	10.6%	9.5%	10.3%	5.3%	1.2%	2.2%
Canning Vale	WCVE	Urban	-1.20%	0.59%	0.35%	10.6%	9.5%	10.3%	5.3%	1.2%	2.2%
Clarence Street	WCLN	Urban	-1.20%	0.59%	0.35%	10.6%	9.5%	10.3%	5.3%	1.2%	2.2%
Clarkson	WCKN	Urban	-1.20%	0.59%	0.35%	10.6%	9.5%	10.3%	5.3%	1.2%	2.2%
Cockburn Cement	WCCT	Urban	-1.20%	0.59%	0.35%	10.6%	9.5%	10.3%	5.3%	1.2%	2.2%
Collier	WCOL	Urban	-1.20%	0.59%	0.35%	10.6%	9.5%	10.3%	5.3%	1.2%	2.2%
Cottesloe	WCTE	Urban	-1.20%	0.59%	0.35%	10.6%	9.5%	10.3%	5.3%	1.2%	2.2%
Edmund Street	WEDD	Urban	-1.20%	0.59%	0.35%	10.6%	9.5%	10.3%	5.3%	1.2%	2.2%
Forrestfield	WFFD	Urban	-1.20%	0.59%	0.35%	10.6%	9.5%	10.3%	5.3%	1.2%	2.2%
Gosnells	WGNL	Urban	-1.20%	0.59%	0.35%	10.6%	9.5%	10.3%	5.3%	1.2%	2.2%
Hadfields	WHFS	Urban	-1.20%	0.59%	0.35%	10.6%	9.5%	10.3%	5.3%	1.2%	2.2%
Hazelmere	WHZM	Urban	-1.20%	0.59%	0.35%	10.6%	9.5%	10.3%	5.3%	1.2%	2.2%
Henley Brook	WHBK	Urban	-1.20%	0.59%	0.35%	10.6%	9.5%	10.3%	5.3%	1.2%	2.2%
Herdsman Parade	WHEP	Urban	-1.20%	0.59%	0.35%	10.6%	9.5%	10.3%	5.3%	1.2%	2.2%
Joel Terrace	WJTE	Urban	-1.20%	0.59%	0.35%	10.6%	9.5%	10.3%	5.3%	1.2%	2.2%
Joondalup	WJDP	Urban	-1.20%	0.59%	0.35%	10.6%	9.5%	10.3%	5.3%	1.2%	2.2%
Joondanna	WJDA	Urban	-1.20%	0.59%	0.35%	10.6%	9.5%	10.3%	5.3%	1.2%	2.2%
Kalamunda	WKDA	Urban	-1.20%	0.59%	0.35%	10.6%	9.5%	10.3%	5.3%	1.2%	2.2%
Kambalda	WKBA	Urban	-1.20%	2.50%	2.20%	10.6%	9.5%	10.3%	5.3%	2.8%	3.2%
Kewdale	WKDL	Urban	-1.20%	0.59%	0.35%	10.6%	9.5%	10.3%	5.3%	1.2%	2.2%
Landsdale	WLDE	Urban	-1.20%	0.59%	0.35%	10.6%	9.5%	10.3%	5.3%	1.2%	2.2%
Malaga	WMLG	Urban	-1.20%	0.59%	0.35%	10.6%	9.5%	10.3%	5.3%	1.2%	2.2%
Mandurah	WMHA	Urban	-1.20%	0.59%	0.35%	10.6%	9.5%	10.3%	5.3%	1.2%	2.2%
Manning Street	WMAG	Urban	-1.20%	0.59%	0.35%	10.6%	9.5%	10.3%	5.3%	1.2%	2.2%
Mason Road	WMSR	Urban	-1.20%	0.59%	0.35%	10.6%	9.5%	10.3%	5.3%	1.2%	2.2%
Meadow Springs	WMSS	Urban	-1.20%	0.59%	0.35%	10.6%	9.5%	10.3%	5.3%	1.2%	2.2%
Medical Centre	WMCR	Urban	-1.20%	0.59%	0.35%	10.6%	9.5%	10.3%	5.3%	1.2%	2.2%
Medina	WMED	Urban	-1.20%	0.59%	0.35%	10.6%	9.5%	10.3%	5.3%	1.2%	2.2%
Midland Junction	WMJX	Urban	-1.20%	0.59%	0.35%	10.6%	9.5%	10.3%	5.3%	1.2%	2.2%
Morley	WMOY	Urban	-1.20%	0.59%	0.35%	10.6%	9.5%	10.3%	5.3%	1.2%	2.2%
Mullaloo	WMUL	Urban	-1.20%	0.59%	0.35%	10.6%	9.5%	10.3%	5.3%	1.2%	2.2%
Mundaring Weir	WMWR	Urban	-1.20%	0.59%	0.35%	10.6%	9.5%	10.3%	5.3%	1.2%	2.2%

Zone Substation	TNI	Pricing Zone	Transmission			Distribution			Bundled		
			Fixed charge for first 1000 kVA (c per day)	Demand charge for 1000<kVA<7000 (c/kVA/day)	Demand Charge for kVA > 7000 (c/kVA/day)	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)	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)
Munday	WMDY	Urban	-1.20%	0.59%	0.35%	10.6%	9.5%	10.3%	5.3%	1.2%	2.2%
Murdoch	WMUR	Urban	-1.20%	0.59%	0.35%	10.6%	9.5%	10.3%	5.3%	1.2%	2.2%
Myaree	WMYR	Urban	-1.20%	0.59%	0.35%	10.6%	9.5%	10.3%	5.3%	1.2%	2.2%
Nedlands	WNED	Urban	-1.20%	0.59%	0.35%	10.6%	9.5%	10.3%	5.3%	1.2%	2.2%
North Beach	WNBH	Urban	-1.20%	0.59%	0.35%	10.6%	9.5%	10.3%	5.3%	1.2%	2.2%
North Fremantle	WNFL	Urban	-1.20%	0.59%	0.35%	10.6%	9.5%	10.3%	5.3%	1.2%	2.2%
North Perth	WNPH	Urban	-1.20%	0.59%	0.35%	10.6%	9.5%	10.3%	5.3%	1.2%	2.2%
OConnor	WOCN	Urban	-1.20%	0.59%	0.35%	10.6%	9.5%	10.3%	5.3%	1.2%	2.2%
Osborne Park	WOPK	Urban	-1.20%	0.59%	0.35%	10.6%	9.5%	10.3%	5.3%	1.2%	2.2%
Padbury	WPBY	Urban	-1.20%	0.59%	0.35%	10.6%	9.5%	10.3%	5.3%	1.2%	2.2%
Piccadilly	WPCY	Urban	-1.20%	1.74%	1.50%	10.6%	9.5%	10.3%	5.3%	2.0%	2.6%
Riverton	WRTN	Urban	-1.20%	0.59%	0.35%	10.6%	9.5%	10.3%	5.3%	1.2%	2.2%
Rivervale	WRVE	Urban	-1.20%	0.59%	0.35%	10.6%	9.5%	10.3%	5.3%	1.2%	2.2%
Rockingham	WROH	Urban	-1.20%	0.59%	0.35%	10.6%	9.5%	10.3%	5.3%	1.2%	2.2%
Shenton Park	WSPA	Urban	-1.20%	0.59%	0.35%	10.6%	9.5%	10.3%	5.3%	1.2%	2.2%
Sth Ftle Power Station	WSFT	Urban	-1.20%	0.59%	0.35%	10.6%	9.5%	10.3%	5.3%	1.2%	2.2%
Southern River	WSNR	Urban	-1.20%	0.59%	0.35%	10.6%	9.5%	10.3%	5.3%	1.2%	2.2%
Tate Street	WTTS	Urban	-1.20%	0.59%	0.35%	10.6%	9.5%	10.3%	5.3%	1.2%	2.2%
University	WUNI	Urban	-1.20%	0.59%	0.35%	10.6%	9.5%	10.3%	5.3%	1.2%	2.2%
Victoria Park	WVPA	Urban	-1.20%	0.59%	0.35%	10.6%	9.5%	10.3%	5.3%	1.2%	2.2%
Waikiki	WWAI	Urban	-1.20%	0.59%	0.35%	10.6%	9.5%	10.3%	5.3%	1.2%	2.2%
Wangara	WWGA	Urban	-1.20%	0.59%	0.35%	10.6%	9.5%	10.3%	5.3%	1.2%	2.2%
Wanneroo	WWNO	Urban	-1.20%	0.59%	0.35%	10.6%	9.5%	10.3%	5.3%	1.2%	2.2%
Welshpool	WWEL	Urban	-1.20%	0.59%	0.35%	10.6%	9.5%	10.3%	5.3%	1.2%	2.2%
Wembley Downs	WWDN	Urban	-1.20%	0.59%	0.35%	10.6%	9.5%	10.3%	5.3%	1.2%	2.2%
Willeton	WWLN	Urban	-1.20%	0.59%	0.35%	10.6%	9.5%	10.3%	5.3%	1.2%	2.2%
Yokine	WYKE	Urban	-1.20%	0.59%	0.35%	10.6%	9.5%	10.3%	5.3%	1.2%	2.2%

8.3.5 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 31

Pricing Zone	Demand-Length Charge For kVA >1000 and first 10 km length % Change	Demand-Length Charge For kVA >1000 and length in excess of 10 km % Change
CBD	N/A	N/A
Urban	10.3%	10.3%
Mining	10.4%	10.1%
Mixed	15.3%	15.4%
Rural	10.3%	10.5%

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 32

Pricing Zone	Demand-Length Charge For first 10 km length % Change	Demand-Length Charge For length in excess of 10 km % Change
CBD	N/A	N/A
Urban	10.3%	10.3%
Mining	10.2%	10.4%
Mixed	15.3%	15.3%
Rural	10.3%	10.2%

8.3.6 Metering Prices

The % changes in the following table are applicable for reference tariffs: **RT5, RT6, RT7, RT8** and **RT11**.

Table 33

Metering Equipment Funding	Voltage	% Change
Western Power funded	High Voltage (6.6 kV or higher)	-22.3%
	Low voltage (415 volts or less)	-22.3%
Customer funded	High Voltage (6.6 kV or higher)	3.0%
	Low Voltage (415 volts or less)	3.0%

8.3.7 Administration Prices

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

Table 34

Peak Demand	% Change
>=7,000 kVA	15.0%
<7,000 kVA	15.0%

8.3.8 Low Voltage Prices

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

Table 35

Category	% Change
Fixed	8.1%
Demand	27.7%

8.3.9 Connection Prices

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

Table 36

	Connection Price % Change
Connection Price	3.1%

8.3.10 Transmission Use of System Prices

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

Table 37

Substation	TNI	Use of System Price % Change
Albany	WALB	-0.8%
Alcoa Pinjarra	WAPJ	-2.7%
Amherst	WAMT	1.0%
Arkana	WARK	-2.6%
Australian Fused Materials	WAFM	7.3%
Australian Paper Mills	WAPM	7.3%
Baandee (WC)	WBDE	-2.7%
Beckenham	WBEC	2.3%
Beechboro	WBCH	4.0%
Beenup	WBNP	7.3%
Belmont	WBEL	-0.1%
Bentley	WBTY	-2.7%
Bibra Lake	WBIB	-2.7%
Binningup Desalination Plant	WBDP	-2.7%
Black Flag	WBKF	7.3%
Boddington Gold	WBGM	7.3%
Boddington (Local)	WABD	7.3%
Boddington Reynolds	WRBD	2.3%
Boulder	WBLD	3.3%
Bounty	WBNY	0.4%
Bridgetown	WBTN	7.3%
British Petroleum	WBPM	7.3%
Broken Hill Kwinana	WBHK	7.3%
Bunbury Harbour	WBUH	7.3%
Busselton	WBSN	-2.7%
Byford	WBYF	7.3%
Canning Vale	WCVE	7.3%

Substation	TNI	Use of System Price % Change
Capel	WCAP	-2.2%
Carrabin	WCAR	-2.7%
Cataby Kerr McGee	WKMC	-2.7%
Chapman	WCPN	-2.7%
Clarence Street	WCLN	7.3%
Clarkson	WCKN	-2.7%
Cockburn Cement	WCCT	7.3%
Cockburn Cement Ltd	WCCL	7.3%
Collie	WCOE	-2.7%
Collier	WCOL	7.3%
Cook Street	WCKT	-2.7%
Coolup	WCLP	7.3%
Cottesloe	WCTE	-2.7%
Cunderdin	WCUN	-2.7%
Darlington	WDTN	7.3%
Edgewater	WEDG	-2.7%
Edmund Street	WEDD	3.9%
Eneabba	WENB	-2.7%
Forrest Ave	WFRT	7.3%
Forrestfield	WFFD	7.3%
Geraldton	WGTN	-2.7%
Glen Iris	WGNI	7.3%
Golden Grove	WGGV	-2.7%
Gosnells	WGNL	7.3%
Hadfields	WHFS	7.3%
Hay Street	WHAY	-2.7%
Hazelmere	WHZM	-2.7%
Henley Brook	WHBK	7.3%
Herdsman Parade	WHEP	5.3%
Joel Terrace	WJTE	7.3%
Joondalup	WJDP	-2.7%
Kalamunda	WKDA	7.3%
Katanning	WKAT	-2.7%
Kellerberrin	WKEL	-2.7%
Kojonup	WKOJ	7.3%
Kondinin	WKDN	-2.7%
Kwinana Alcoa	WAKW	7.3%
Kwinana Desalination Plant	WKDP	7.3%
Kwinana PWS	WKPS	
Landsdale	WLDE	-2.7%
Maddington	WMDN	
Malaga	WMLG	-1.7%
Mandurah	WMHA	-2.2%
Manjimup	WMJP	7.3%
Manning Street	WMAG	-2.7%
Margaret River	WMRV	-2.7%
Marriott Road Barrack Silicon Smelter	WBSI	-2.7%
Marriott Road (Local)	WLMR	-2.7%
Mason Road	WMSR	7.3%
Mason Road CSBP	WCBP	7.3%

Substation	TNI	Use of System Price % Change
Mason Road Hismelt	WHIS	7.3%
Mason Road Kerr McGee	WKMK	7.3%
Meadow Springs	WMSS	-1.8%
Medical Centre	WMCR	2.1%
Medina	WMED	7.3%
Merredin 66kV	WMER	-2.7%
Midland Junction	WMJX	-2.7%
Milligan Street	WMIL	-2.7%
Moora	WMOR	7.3%
Morley	WMOY	-2.7%
Mt Barker	WMBR	-2.5%
Muchea Kerr McGee	WKMM	7.3%
Muchea (Local)	WLMC	7.3%
Muja PWS	WMPS	
Mullaloo	WMUL	-2.7%
Murdoch	WMUR	-2.7%
Mundaring Weir	WMWR	4.5%
Myaree	WMYR	4.8%
Narrogin	WNGN	-2.7%
Nedlands	WNED	4.7%
North Beach	WNBH	-2.7%
North Fremantle	WNFL	0.5%
North Perth	WNPH	1.6%
Northam	WNOR	-2.7%
O'Connor	WOCN	7.3%
Osborne Park	WOPK	-2.7%
Padbury	WPBY	-2.7%
Parkeston	WPRK	7.3%
Parklands	WPLD	-2.7%
Piccadilly	WPCY	1.9%
Picton 66kv	WPIC	0.8%
Pinjarra	WPNJ	-2.4%
Rangeway	WRAN	7.3%
Regans	WRGN	-2.7%
Riverton	WRTN	-2.7%
Rivervale	WRVE	-2.7%
Rockingham	WROH	-2.7%
Sawyers Valley	WSVY	-2.7%
Shenton Park	WSPA	6.1%
Southern River	WSNR	7.3%
South Fremantle 22kV	WSFT	7.3%
Summer St	WSUM	-2.7%
Tate Street	WTTS	7.3%
Three Springs	WTSG	-0.8%
Tomlinson Street	WTLN	-2.7%
University	WUNI	7.3%
Victoria Park	WVPA	7.3%
Wagerup	WWGP	-2.7%
Wagin	WWAG	7.3%
Waikiki	WWAI	-2.7%

Substation	TNI	Use of System Price % Change
Wangara	WWGA	-2.7%
Wanneroo	WWNO	-2.7%
WEB Grating	WWEB	-2.7%
Wellington Street	WWNT	7.3%
Welshpool	WWEL	-2.7%
Wembley Downs	WWDN	3.3%
West Kalgoorlie	WWKT	6.5%
Western Collieries	WWCL	7.3%
Western Mining	WWMG	7.3%
Westralian Sands	WWSD	-2.7%
Willeton	WWLN	4.6%
Worsley	WWOR	7.3%
Wundowie	WWUN	-1.7%
Yanchep	WYCP	-2.7%
Yerbillon	WYER	-2.7%
Yilgarn	WYLN	-2.7%
Yokine	WYKE	-2.7%

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

Table 38

Substation	TNI	Use of System % Change
Albany Windfarm	WALB	-18.3%
Boulder	WBLD	-18.3%
Bluewaters	WBWP	-18.3%
Cockburn PWS	WCKB	-18.3%
Collgar	WCWG	-8.3%
Collie PWS	WCPS	-16.7%
Emu Downs	WEMD	-8.3%
Geraldton GT	WGTN	-18.3%
Kemerton PWS	WKEM	-18.3%
Kwinana Alcoa	WAKW	-8.3%
Kwinana Donaldson Road (Western Energy)	WKND	-18.3%
Kwinana PWS	WKPS	-18.3%
Landweir (Alinta)	WLWT	-18.3%
Mason Road	WMSR	-18.3%
Mason Road Hismelt	WHIS	-18.3%
Merredin Power Station	TMDP	-8.3%
Muja PWS	WMPS	-8.3%
Mungarra GTs	WMGA	-8.3%
Newgen Kwinana	WNGK	-9.9%
Newgen Neerabup	WGNN	-8.3%
Oakley (Alinta)	WOLY	-18.3%
Parkeston	WPKS	-18.3%
Pinjar GTs	WPJR	-8.3%
Alcoa Pinjarra	WAPJ	-18.3%

Substation	TNI	Use of System % Change
Tiwest GT	WKMK	-18.3%
Wagerup Alcoa	WAWG	-12.9%
Walkaway Windfarm	WWWF	-8.3%
West Kalgoorlie GTs	WWKT	-18.3%
Worsley	WWOR	-18.3%

8.3.11 Common Service Prices

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

Table 39

	Common Service Price % Change
Common Service Price	-0.2%

8.3.12 Control System Service Prices

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

Table 40

	Price % Change
Control System Service Price (Generators)	-34.9%

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

Table 41

	Price % Change
Control System Service Price (Loads)	-29.1%

8.3.13 Metering Prices

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

Table 42

	% Change
Transmission Metering	0%

Appendix A - 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.