Price List Information

ELECTRICITY NETWORKS CORPORATION
(“WESTERN POWER”)

ABN 18 540 492 861

{Outline: This *price list information* is included in Western Power’s *access arrangement* in accordance with section 5.1 of the *Code*.}

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1 Introduction

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

This document details:

- The history of the network tariffs;
- 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 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 History of the Tariffs

Prior to the commencement of the Access Code 2004 and the 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.

Users that were contestable prior to July 2001 were given the option of remaining on the previous tariffs or migrating to the new tariffs. This is facilitated by the retention of a set of transition tariffs. Users were permitted to choose the tariff that suited them. However the transition tariffs are indexed by cpi plus two percent each year with a view of phasing them out over time as the standard tariffs become cheaper than the transition tariffs. There are in fact only about 30 users still on transition tariffs and this number is expected to drop considerably over the next few years.

Western Power has retained the network tariff structure for the reference services offered under the Access Arrangement. It is the derivation of these reference tariffs that the remainder of this document is dedicated to.

2 Pricing Principles

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

2.1 Pricing Objectives

Western Power's target revenue is based on price control methodology detailed in the Access Arrangement. Target revenue is recovered through revenue from covered services and capital contributions, as shown in the following formula:

```
Target Revenue = Reference Service Revenue + Non Reference Service Revenue
                 + Capital Contributions
```

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

The reference service revenue (the focus of this document) is recovered through a set of reference tariffs that have been designed to meet high-level objectives described below.

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. From an economic efficiency perspective this requires that the reference tariff be between the "floor" price, which is the incremental cost of supply, and a "ceiling" price represented by 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. Reference tariffs are to be designed to recover the reference service 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 within classes 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) will meet the pricing principles described above, as far as is practical.

2.3 Pricing Methodology

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 not a completely definitive process. A number of simplifying assumptions are required, for example, the categorising of users into a small number of customer groups or classes. These assumptions may introduce errors that are considered to not be significant and there is considerable historical precedence in deriving the network cost of supply that supports the approach.

Demand is the best measurement of capacity but as the vast majority of users have energy only metering that does not record demand; energy is used as a proxy for demand. The limitations on the metering information available will introduce minor non-deterministic errors that cannot be avoided or quantified.

2.3.2 Process to Determine Cost of Supply

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

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

- Determination of the target revenue and 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.

Determination of the target revenue requirement for Western Power is outside the scope of this paper and is assumed to be determined in accordance with the Access Arrangement. The determination of the reference services revenue is shown in the following formula.

```
Reference Service Revenue = Target Revenue – Non Reference Service Revenue
                            – Capital Contributions
```

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

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 reflects 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 >1MVA maximum demand
- High Voltage <1MVA maximum demand
- Low Voltage >1MVA 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 in sections 5 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.

Within this document tables from Western Power's COS model are included to demonstrate that Western Power is compliant with the 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

  - o Common Service for Loads Cost Pool.

- Control System Services Cost Pool:
  which is further allocated to the following cost pools,
  - o Control System Services for Loads Cost Pool,
  - o 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 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. NB The remaining one-third of the value of the voltage control equipment at Entry and Exit points is included in the Connection Services Cost Pool (see above).
- Generation Support Charge - is an annual pass through cost determined by the market operator for running some small generation units out of merit in order to minimise excessive transmission losses and aid in system stability.

- Regulation Service to Loads - is an annual pass through cost determined by the market operator required to control frequency variations caused by load fluctuations (see Western Power Networks, 'Price Publication – Part E').
- Adjustments for any under or over recovery in revenue from previous financial years, or any under recovery expected due to price caps in the current year.

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 (Gross Optimised Deprival Value) 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

Indicative Diagram

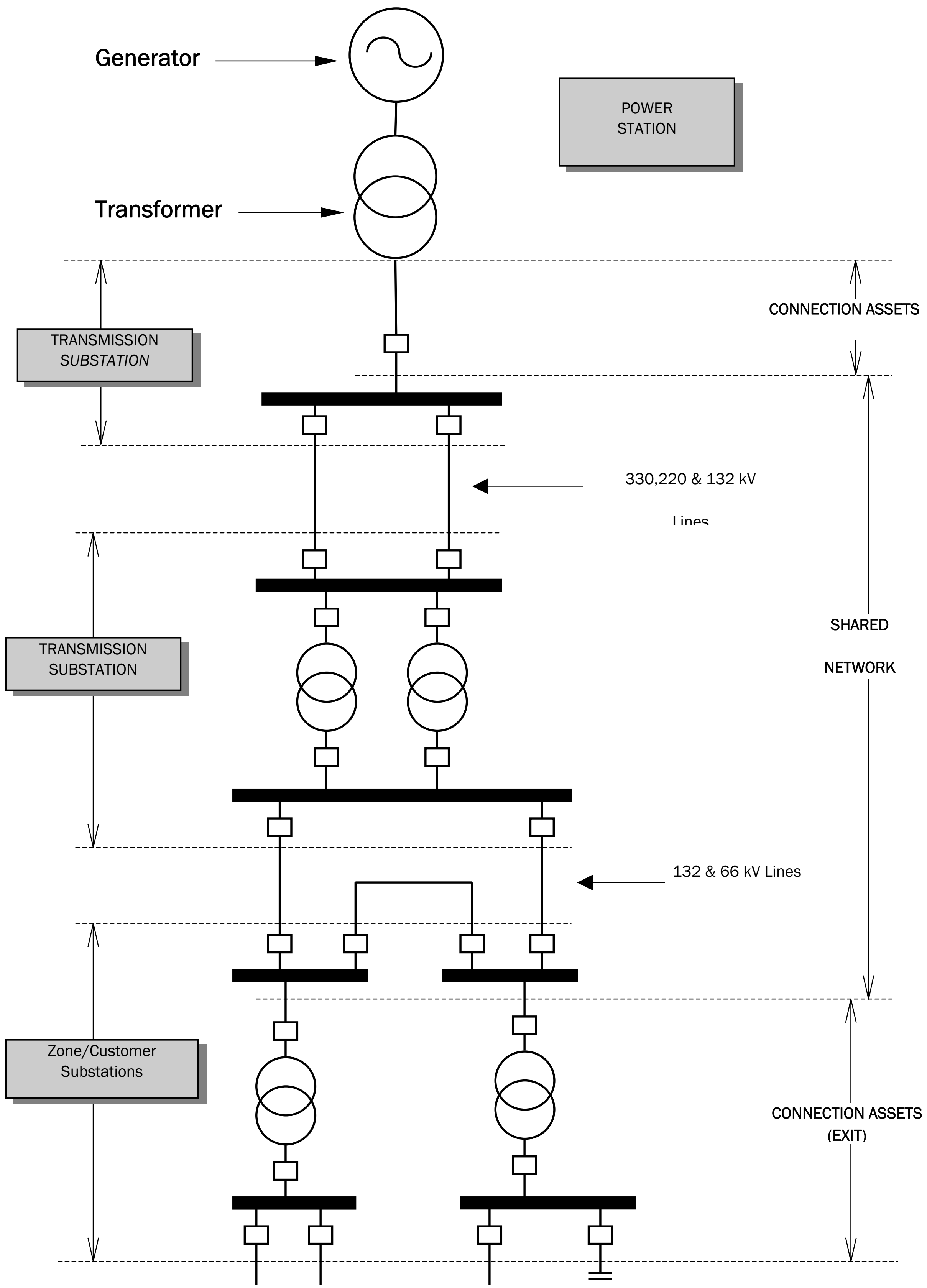


Figure 1 - Transmission Network Assets

3.2.2 Asset Valuation

A valuation of transmission assets is undertaken using the Optimised Deprival Value methodology. Detail of the methodology and outcomes is within the “Physical Assets Valuation as at 30 June 2004, Distribution and Transmission Networks, Report to the Valuation Committee” included within the Access Arrangement Information.

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 (RR) 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 (before applying pricing side constraints) for 2006/07:

Table 1 - Transmission Revenue for 2006/07 (Nominal $k)

	Revenue
Smoothed Annual Reference Service Revenue (excluding Transition Tariff and Standby services)	179,619
Non Reference Service Revenue from Transition Tariffs and Standby services	12,133
Total Transmission Revenue for pricing purposes	**191,752**

Table 2 - Transmission Pricing Cost Pools for 2006/07 (Nominal $k)

Cost Pool	Allocated Revenue
Entry Connection	3,888
Exit Connection HV	316
Exit Connection LV	46,656
Use Of System for Generators	24,189
Use Of System for Loads	60,473
Common Service for Loads (including Voltage Control)	45,693
Control System Services for Loads	8,744
Control System Services for Generators	1,543
Metering CT/VT	250
Total	**191,752**

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 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 >1MVA maximum demand
- High Voltage <1MVA maximum demand
- Low Voltage >1MVA 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, eg, 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, eg, 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.

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.

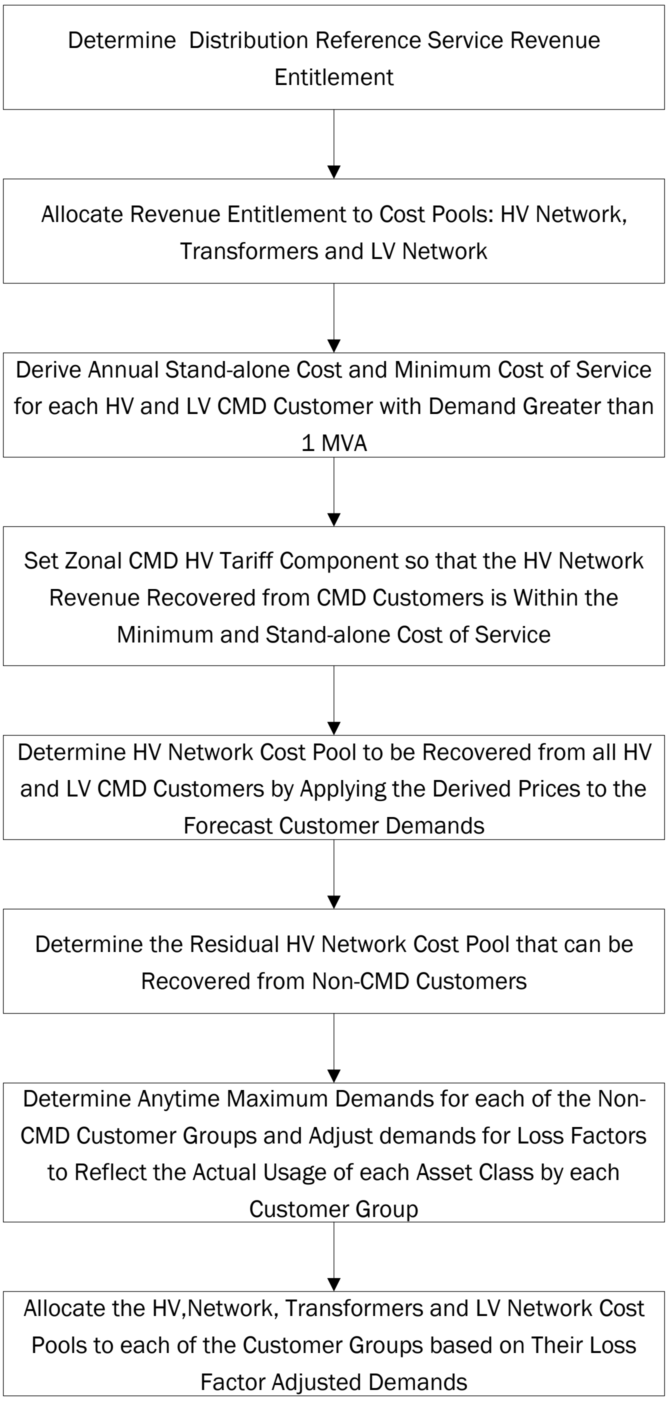


Figure 2 - Distribution Cost of Supply Flow Chart

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

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 ERA in the Access Arrangement.

The forecast revenue to be recovered from capital contributions is deducted from the total distribution revenue entitlement to give the forecast revenue to be recovered from tariffs.

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 gross ODV of each asset category as a proportion of the total gross ODV.

4.4.4 Derive HV Annual Stand-alone Cost and Incremental Cost of Supply for each 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 being affected by their location on the network and their 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 cost of supply and the stand-alone cost. This approach is consistent with the requirements of section 7.3 of the Code and demonstrated within the Access Arrangement.

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 be 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, and
- 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 (%)
Un-metered	8
Street Lights	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 recent 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 these capital related costs should be allocated on demand.

4.4.7.2 Operating and maintenance costs

A proportion of the costs associated with operations and maintenance could be said to be simply because the lines and cables are there, while other costs are clearly load related.

Maintenance work such as routine inspection and repair could be allocated in part for the asset being there and in part to retain capacity. 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 Street Lighting Costs

Allocation of network costs to street lighting is in two components, namely the use of network costs and the costs associated with the street light asset itself.

4.4.10.1 Use of Network Costs

Street lighting does not contribute to system peak load, which occurs mid afternoon in summer. In winter, the lighting load coincides with the evening peak but because the various network elements have a higher rating in the colder conditions, street lighting effectively does not contribute to network costs but simply assists in improving the load factor.

On this basis, no transmission or distribution HV costs are allocated to street lighting. LV and transformer costs are allocated on a fixed and variable basis as for other customer groups.

4.4.10.2 Street Light Asset Costs

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

4.4.11 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.

4.4.12 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 cost pools are derived:

Table 3 - Distribution Revenue for 2006/07 (Nominal $M)

	Revenue
Smoothed Annual Reference Service Revenue (includes TEC)	374.6
Non Reference Service Revenue from Transition Tariffs and Standby services	3.6
Total Distribution Revenue for pricing purposes	**378.2**

Table 4 - Distribution Cost Pools for 2006/07 (Nominal $M)

	Locational Zone					
Cost Pool	CBD	Urban	Goldfields Mining	Mixed	Rural	Total
High Voltage Network	-1.0	27.7	0.4	31.7	54.5	113.4
High Voltage Network > 1,000 kVA	3.7	10.2	1.9	3.7	1.5	21.0
High Voltage Network Total	**2.7**	**38.0**	**2.4**	**35.3**	**56.0**	**134.4**
Low Voltage Network	1.8	49.9	0.1	11.4	4.7	67.9
Transformers	1.8	15.9	0.4	9.4	8.2	35.7
Streetlight Assets						10.0
Metering						45.1
Administration						85.2
TOTAL Reference Service Revenue						**378.2**

Table 5 - Distribution Customer Groups for 2006/07 (Nominal $M)

								High Voltage Network		Low Voltage Network		Transformers	Streetlight Assets	Metering	Administration
Customer Group	ATMD kVA	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	4,791	31	5,191	5,191	5,191	13,955	13,955	0.3	0.1	0.3	0.1	0.0	0.0	0.0	0.4
Streetlights	24,762	99	26,830	26,830	2,683	201,694	20,169	0.8	0.6	0.4	0.0	0.3	10.0	0.0	1.0
Residential	1,629,827	4,627	1,765,917	1,765,917	1,765,917	785,062	785,062	24.7	37.6	15.1	29.4	17.2	0.0	32.6	51.6
Small Business	493,993	1,109	516,864	516,864	516,864	85,998	85,998	6.6	15.8	1.4	8.5	6.2	0.0	6.7	12.1
General Business - Small	439,808	1,138	460,171	460,171	460,171	13,716	13,716	0.6	11.7	0.2	7.5	5.0	0.0	2.6	9.3
General Business - Medium	284,647	904	297,826	297,826	268,044	1,717	1,545	0.0	5.6	0.0	4.3	2.8	0.0	1.4	5.8
General Business - Large	301,021	932	311,045	311,045	31,104	600	60	0.0	5.6	0.0	0.5	2.9	0.0	0.6	2.2
LV greater than 1000kVA	135,927	431	140,454	140,454	14,045	93	9	1.2	3.5	0.0	0.2	1.2	0.0	0.1	0.5
HV less than 1000kVA	75,201	293	76,788	0	0	287	0	0.0	1.5	0.0	0.0	0.0	0.0	0.4	1.0
HV>1000	798,168	2,981	815,010	0	0	228	0	5.6	12.6	0.0	0.0	0.0	0.0	0.7	1.3
TOTAL	4,188,145	12,546	4,416,096	3,524,299	3,064,020	1,103,350	920,514	39.8	94.6	17.4	50.5	35.7	10.0	45.1	85.2

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 & Tariff Structure

The following table details the relationship between the reference services, detailed in the Access Arrangement, and the reference tariffs.

Table 6 - 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 (Small) Exit Service	RT3
A4 – Time of Use Energy (Large) 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 –Un-Metered Supplies Exit Service	RT10
A11 – Transmission Exit Service	TRT1
B1 – Distribution Entry Service	RT11
B2 – Transmission Entry Service	TRT2

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 is based on:

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

The tariff structure for transmission is based on:

- 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 is based on:

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

The tariff structure for transmission is based on:

- 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 (Small)

The tariff structure for distribution is based on:

- 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 is based on:

- 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 (Large)

The tariff structure for distribution is based on:

- 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 is based on:

- 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 cost of usage of the low voltage distribution network.

5.2.9 RT9 – Streetlighting

Street-lights 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.

The tariff structure for distribution is based on:

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

The tariff structure for transmission is based on:

- A charge per kWh for calculated energy consumption.

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

5.2.10 RT10 – Un-Metered Supplies

Un-metered 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 is based on:

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

The tariff structure for transmission is based on:

- 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” and “common service” charge. There is also a separate metering charge. All prices are in $ per kW.

The tariff structure requires the user to nominate a contract maximum demand (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

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 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 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 the distribution-connected generator 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.

There is also the locational signal for the transmission component of the charge. Generators may or may not be able to respond to this signal depending on their individual circumstances.

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" charge. There is also a separate metering charge. All prices are in $ per kW.

The tariff structure requires the generator to nominate a declared sent out capacity (DSOC), in kWs, that reflects their maximum intended export capacity. There is a monthly penalty for any demand excursion above the DSOC.

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 cost allocation method allocates the revenue requirement to all network elements, based on their gross (ie undepreciated) ODV, then determines the use made of each network element by each connection point during the survey period.

The Cost Reflective Network Pricing cost allocation process requires detailed network analysis and involves the following steps:

1. determining the annual revenue requirement (ARR) 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 NEC 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 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 Prices

Consistent with the NEC, the proportion of the transmission reference service revenue that is for Transmission UOS is allocated to each and every connection point using a Cost Reflective Network Pricing method (CRNP). CRNP assigns a proportion of shared network costs to individual user connection points.

The relativity of Use of System prices for both exit and entry points is calculated using 'T-price' (see below for details). Raw T-price UOS prices are applied to all users based on forecast CMDs and DSOCs and scaled to give the required relevant Cost Pool Revenue.

6.2.3.1 T-Price

Western Power uses T-price to establish the relativity of Use Of System (UOS) prices for each exit and entry point. T-price is a modelling tool to allocate network costs to each node using Cost Reflective Network Pricing. T-price has been given interim approval by NECA for this purpose and is used by all transmission businesses across Australia.

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 every node.
- Load flow analysis is carried out so that all of the network element costs are allocated to each zone substation based on usage of those network elements. This process derives an annual cost for each node.
- The costs at each node 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 – Exit Points

Use of System prices for Exit Points are calculated by scaling raw T-price UOS prices for Exit Points to recover the Use of System for Loads Cost Pool Revenue.

6.2.3.3 UOS – Entry Points

Use of System prices for Entry Points are calculated by scaling raw T-price UOS prices for Entry Points to recover the Use of System for Generators Cost Pool Revenue.

6.2.4 Common Service Price for Loads

The Common Service Price is expressed in $/kW/annum 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 Contract Maximum Demands (over all Exit points where the charge is applied).

6.2.5 Control System Service Price

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

6.2.5.1 CSS for Consumers

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

6.2.5.2 CSS for Generators

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

6.2.6 Transmission Reference Tariff Setting

The following tables provide detailed price list information for transmission reference tariffs.

Table 8 – Control System Services (CSS) Price for Generators for 2006/07

CSS for Generators Cost Pool (excluding GST) (Nominal $k)	1,543
DSOC of Generators for CSS (MW)	4,374
Previous CSS Price for Generators ($/kW including GST)	0.59
New CSS Price for Generators ($/kW including GST)	0.55

N.B. For initial prices, existing side constraint of CPI + 5% was applied.

Table 9 – Control System Services (CSS) Price for Loads for 2006/07

CSS for Loads Cost Pool (excluding GST) (Nominal $k)	8,744
CMD of Loads for CSS (MW)	3,446
Previous CSS Price for Loads ($/kW including GST)	4.19
New CSS Price for Loads ($/kW including GST)	3.86

N.B. For initial prices, existing side constraint of CPI + 5% was applied.

Table 10 – Average Connection Price (for Distribution Pass Through Revenue) for 2006/07

Connection Service Cost Pool (including discounts, excluding GST) (Nominal $k)	45,722
CMD of Connection Service Users (MW)	3,184
Previous Connection Price ($/kW including GST)	15.96
New Connection Price ($/kW including GST)	16.37

Table 11 – Common Service Price for 2006/07

Common Service Cost Pool (excluding GST) (Nominal $k)	36,510
Composite CMD of Common Service Users (MW)	3,342
Previous Common Service Price ($/kW including GST)	16.80
New Common Service Price ($/kW including GST)	15.48

NB

For initial prices, existing side constraint of CPI + 5% was applied.

$10.5M gross over recovery from transmission users passed on to distribution users

Table 12 - Transmission Revenue by Users (after applying all pricing side constraints) for 2006/07

(Nominal $k)

	Revenue
HV Transmission Users	11,391
LV Transmission Users	1,421
Distribution Users (Pass Through)	143,703
Gen Users	34,052
Connection Charge from Additional Loads/Generators (w/o CSS)	934
Metering (CT/VT)	250
Total	**191,752**

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 Contract Maximum Demands (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 >1MVA incorporate transmission nodal prices. The transmission pass-through revenue, net of the revenues from the >1MVA 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. 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 SWIN.

6.3.1 Flow Chart

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

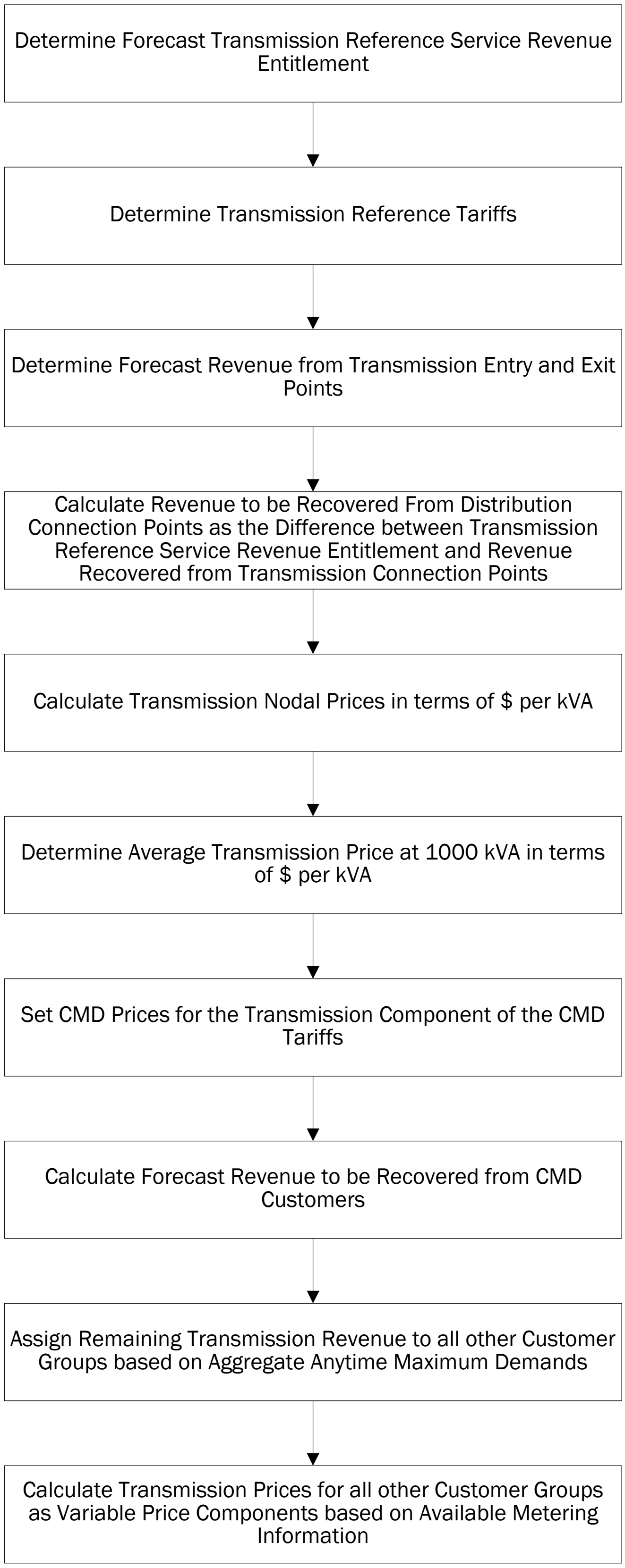


Figure 3 - Derivation of Transmission Tariff Component of Distribution System Flow Chart

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 two primary 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.

The second reason 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 connect 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. None of the other terms is readily determined.

To facilitate the solving of this equation the pricing structure of users with demands between 1,000 and 7,000 kVA must be determined. 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:

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

$*(CMD_{User} – 1,000\ kVA))$

where,

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

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

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

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

The $Price_{1,000\ to\ 7,000}$ will be different for each zone substation 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. 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:

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

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

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

$RP_{1,000\ to\ 7,000}$ = $\sum$ 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

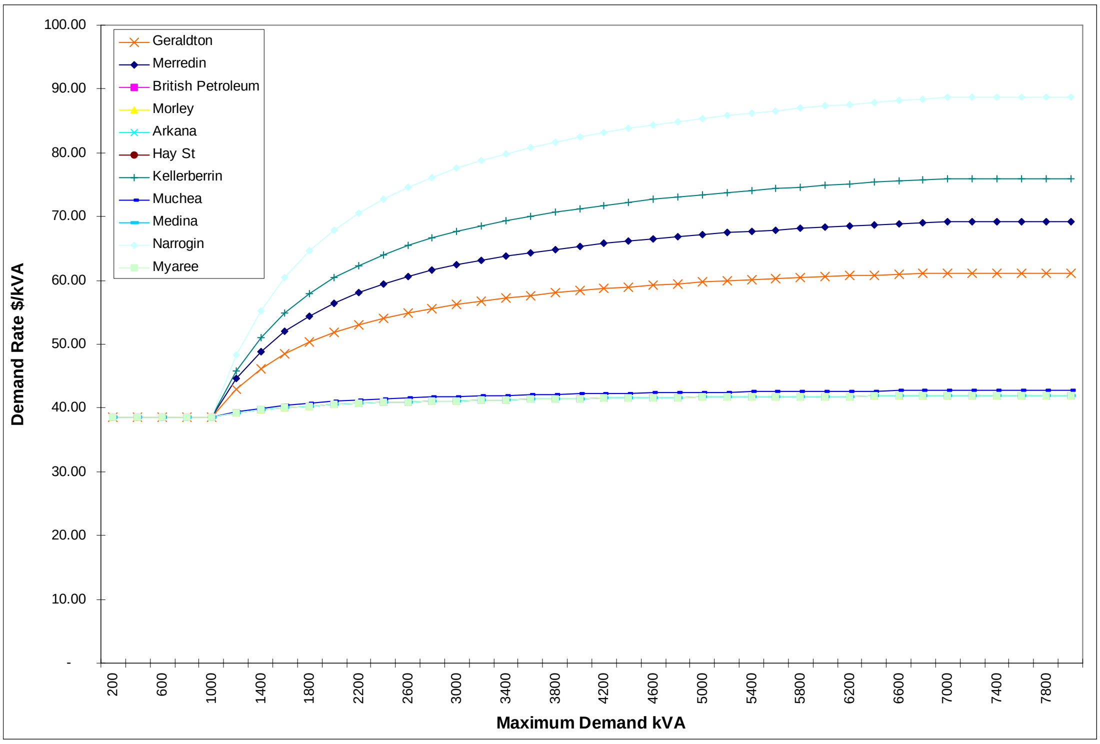


Figure 4 - Rate Blocks Example

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 un-metered supplies, streetlights, energy small and energy large tariffs the price is calculated by the simple formula:

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

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,
- 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 7 - Transmission Reference Service Revenue Recovered from Distribution Connection Points for 2006/07 ($M Nominal)

	kWh	ATMD kVA	Number Customers	Forecast Transmission Revenue Recovered
RT1 - Anytime Energy (Residential)	4,482,841,257	1,579,440	770,503	49.8
RT2 - Anytime Energy (Business)	1,450,899,839	638,391	89,458	19.3
RT3 - Time of Use Energy (Small)	145,045,643	50,387	14,579	1.6
RT4 - Time of Use Energy (Large)	2,015,410,358	709,714	12,120	21.4
RT5 - High Voltage Metered Demand	318,532,427	84,409	97	2.8
RT6 - Low Voltage Metered Demand	969,355,227	283,593	707	10.6
RT7 - High Voltage Contract Maximum Demand	2,745,611,232	723,461	182	36.0
RT8 - Low Voltage Contract Maximum Demand	287,857,276	89,198	55	3.4
RT9 - Streetlighting	99,234,692	24,762	201,694	0.9
RT10 - Un-Metered Supplies	31,212,048	4,791	13,955	0.2
RT11 - Distribution Entry	0	0	0	0.0
TOTAL	**12,546,000,000**	**4,188,145**	**1,103,350**	**145.9**

6.4 Annual Price Review

As described in the Access Arrangement, the Target 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.

Assets are not re-valued annually and T-price is not re-run annually, and the relativity of Use of System prices is consequently maintained. However, all new loads and generators are included and all revised forecast CMDs and DSOCs are updated in the Transmission Pricing Model annually, and prices are consequently scaled annually (within any price control side constraints) to recover the revised Target Revenue.

Transmission Use of System 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, prices are consequently subject to an annual side constraint of plus or minus CPI + 5%.

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 ATMD’s

The Code requires uniform reference tariffs for all users with annual energy demand below 1 MVA, which equates to all but 500 within the SWIN. Users with energy demand below 1MVA 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.

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 8 - Distribution Reference Tariff Components

TARIFF TYPE	TARIFF COMPONENTS							
	Fixed Component	Energy Only	On Peak Energy	Off Peak Energy	Annual Metered Anytime Demand	Off Peak Discount Factor (%)	Contract Maximum Demand (CMD)	Demand/ Length for ATMD > 1,000 kVA
Energy Only Small	*	*						
Energy Only Large	*	*						
Time of Use Energy - Small	*		*	*				
Time of Use Energy - Large	*		*	*				
Metered Demand - LV	*				*	*		*
Metered Demand - HV	*				*	*		*
CMD - LV	*						*	*
CMD - HV	*						*	*
Street Lighting	*	*						
Unmetered	*	*						
Distribution Entry					*			*

7.1.1.1 Energy Only Tariff (Small or Large)

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.

7.1.1.2 Time of Use Energy Tariff (Small or Large)

The tariff comprises of a fixed component ($/annum) and variable on-peak 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 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-peak and off-peak load respectively. The on-peak 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.

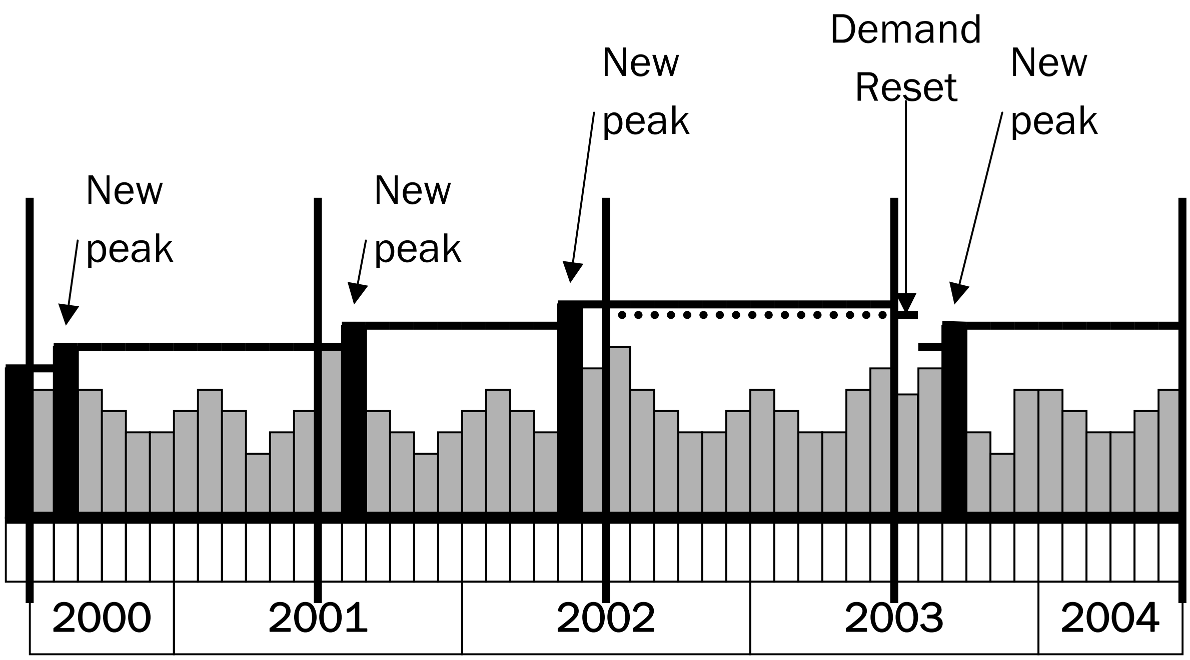
7.1.1.3 Metered Demand Tariff (HV and LV)

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 the 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.

7.1.1.4 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 ach 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, and also 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 relate directly 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.

7.1.1.4.1 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:

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

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 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 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:

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

where,

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

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

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

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

So 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 ($\text{Price}_{At\ 1,000}$) 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:

$RP_{Below\ 1,000} = \sum$ User anytime maximum demands multiplied by $Price_{At\ 1,000}$

RP_{Total} = Total HV network revenue entitlement

$RP_{Over\ 7,000} = \sum$ 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

$RP_{1,000\ to\ 7,000} = \sum$ 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.

7.1.1.4.2 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.

7.1.2 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
- 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 reflects the variation in metering costs.

The metering price structure is as follows:

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

7.1.3 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.

7.1.4 Street Lighting

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 luminare and is based on the annualised cost of capital and maintenance associated with each.

7.1.5 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.

7.2 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.

It is important to note that in the vast majority of cases the price will meet the requirements of section 7.3(b) of the Code. However, no pricing structure can be guaranteed to meet the Code requirement in every individual case. For example if the price is reduced so that the charge is below the stand-alone cost for every single customer, there emerges cases where the price is then below the incremental cost for some other customers. 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.

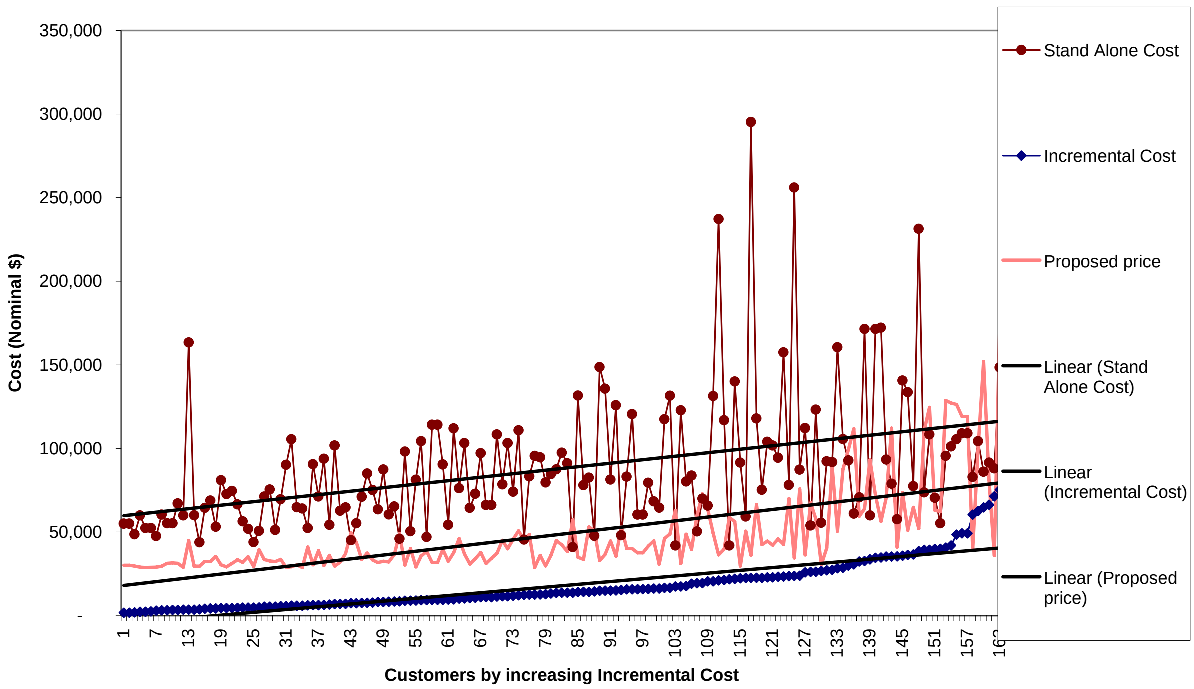


Figure 6- Urban Zone

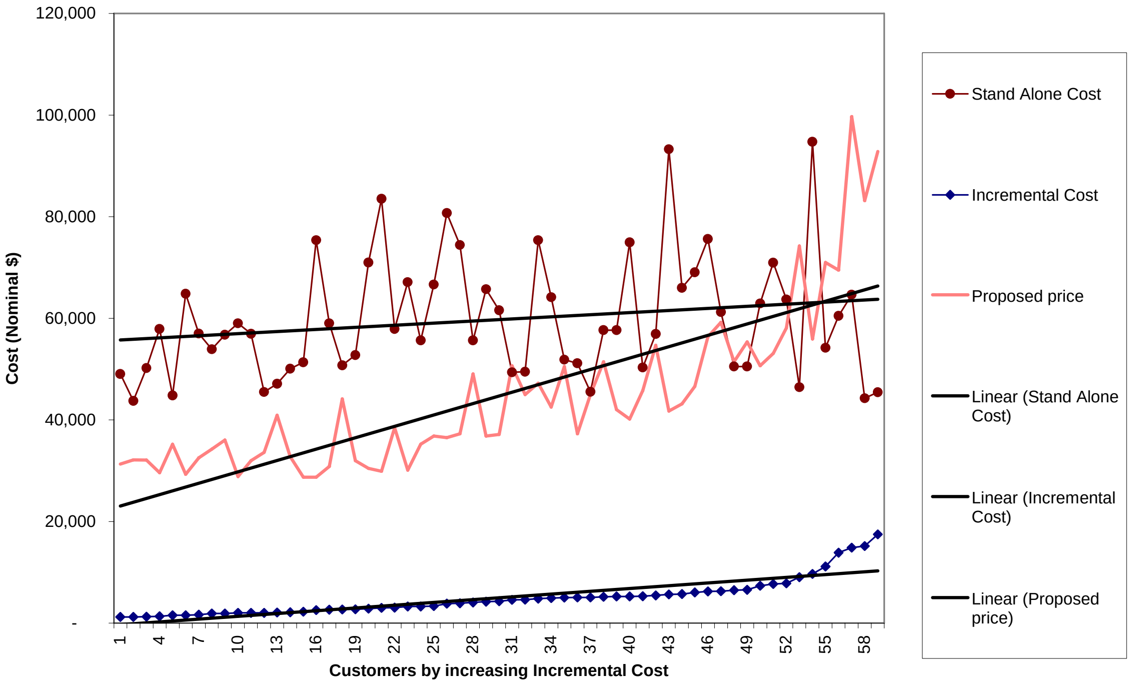


Figure 7 - CBD Zone

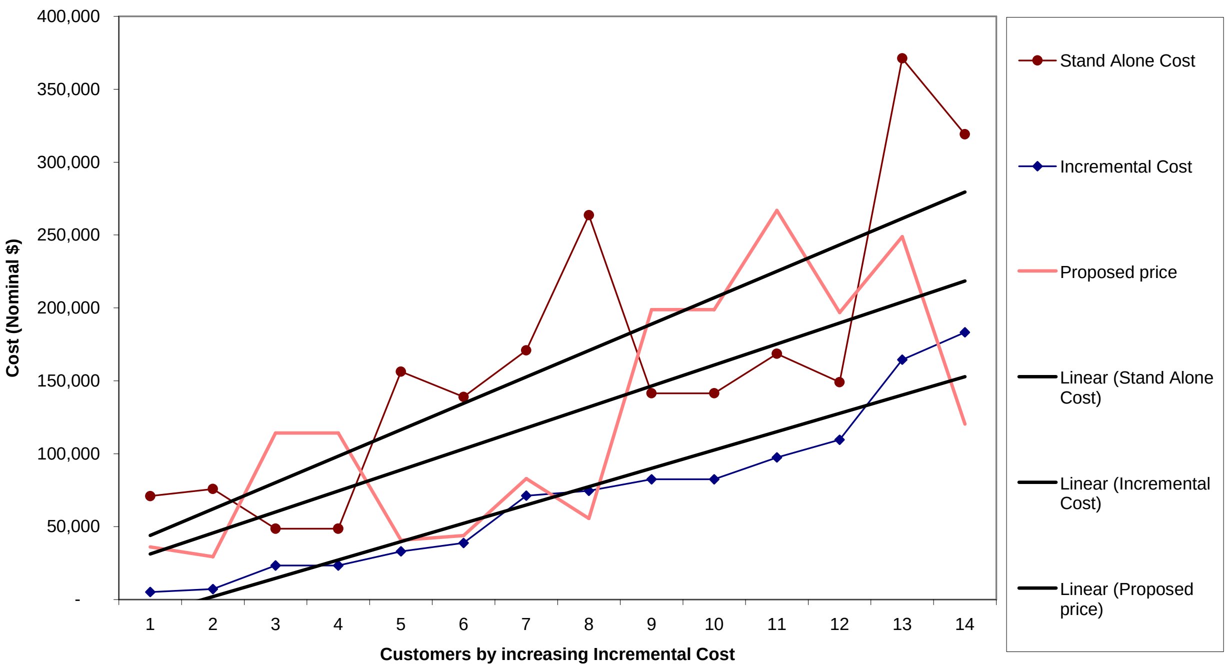


Figure 8 - Mining Zone

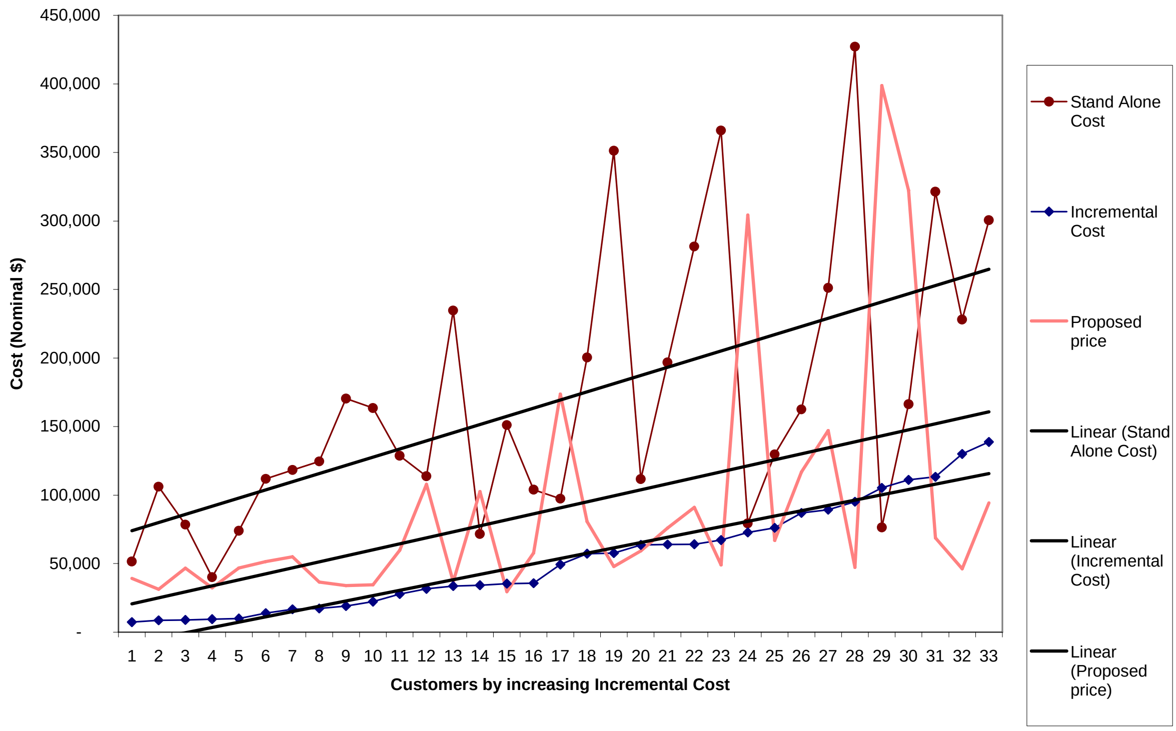


Figure 9 - Mixed Zone

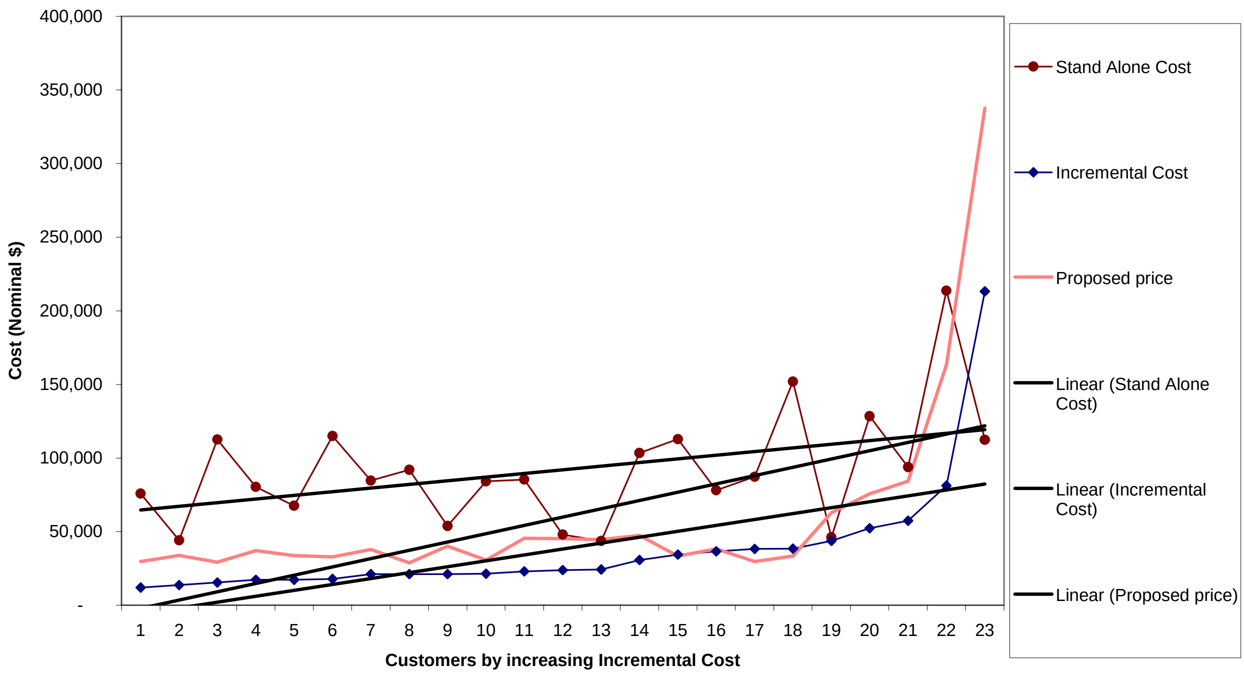


Figure 10 - Rural Zone

7.2.2 Demand/Length Graph

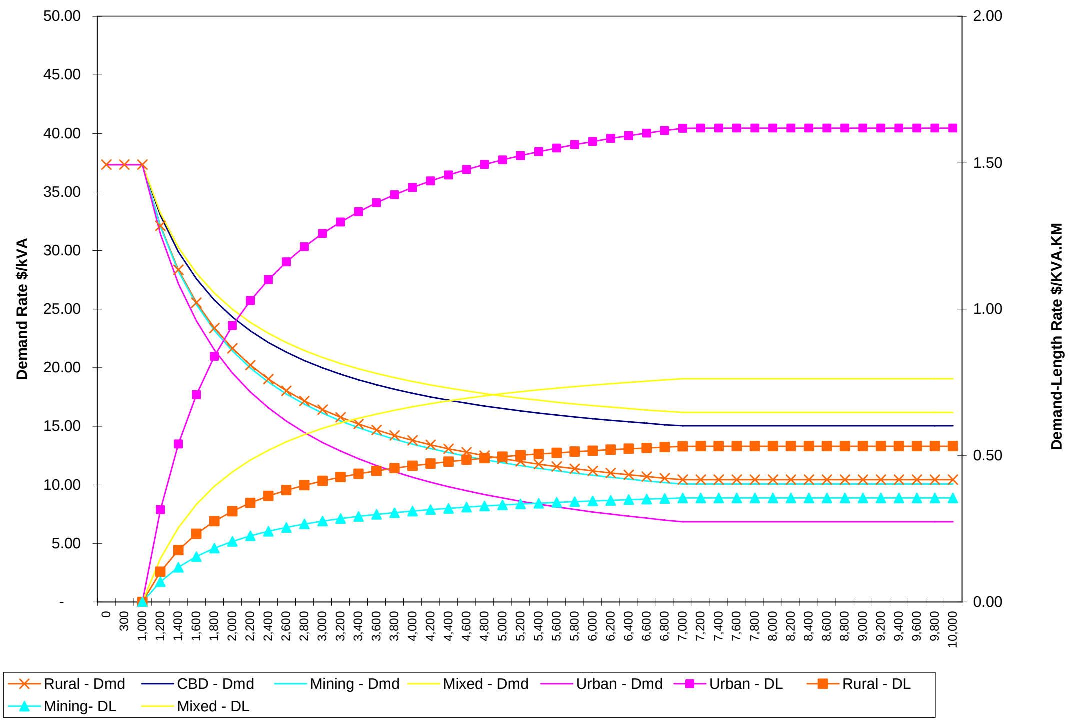


Figure 11 - Demand Length Rates & CMD Rates by Zone

7.2.3 Tariff Forecast Revenue

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

Table 9 - Distribution Reference Service Revenue Recovered from Distribution Connection Points for 2006/07 ($M Nominal)

	kWh	ATMD kVA	Number Customers	Forecast Distribution Revenue Recovered
RT1 - Anytime Energy (Residential)	4,482,841,257	1,579,440	770,503	201.4
RT2 - Anytime Energy (Business)	1,450,899,839	638,391	89,458	67.6
RT3 - Time of Use Energy (Small)	145,045,643	50,387	14,579	5.4
RT4 - Time of Use Energy (Large)	2,015,410,358	709,714	12,120	51.2
RT5 - High Voltage Metered Demand	318,532,427	84,409	97	4.0
RT6 - Low Voltage Metered Demand	969,355,227	283,593	707	17.3
RT7 - High Voltage Contract Maximum Demand	2,745,611,232	723,461	182	15.8
RT8 - Low Voltage Contract Maximum Demand	287,857,276	89,198	55	3.9
RT9 - Streetlighting	99,234,692	24,762	201,694	12.2
RT10 - Un-Metered Supplies	31,212,048	4,791	13,955	1.3

	kWh	ATMD kVA	Number Customers	Forecast Distribution Revenue Recovered
RT11 - Distribution Entry	0	0	0	0.0
TOTAL	12,546,000,000	4,188,145	1,103,350	380.2

7.3 Annual Price Review

At the end of each year, the actual distribution covered service revenue entitlement is reconciled against the actual distribution revenue recovered for that year, and a correction factor applied to the forecast revenue for the subsequent year. Tariffs are then adjusted/rebalanced 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, prices are consequently subject to an annual side constraint of plus or minus CPI + 5%.

8 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.

8.1 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.

(a) 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.

(b) That nominated nodal TUOS price will then be adjusted annually in line with the all capitals consumer price index (CPI).

(c) Once that connection point is established the nominated TUOS price (adjusted in accordance with step (b)) 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) CPI plus 2%. (Thus, the nominated TUOS price will converge over time with and future price based on future T-Price runs.)

(d) The TUOS price will be published once the connection point is commissioned.

(e) 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.

(f) The common service, metering and control system prices that apply in this circumstance will be the standard published prices.

8.2 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.

8.2.1 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 capital contributions policy.

The annual connection price is calculated from the proportion of the regulatory approved maintenance budget to all transmission assets multiplied by the replacement cost of the asset. The allocation in 2005/06 is 2.46% of the full capital cost of the connection asset. Once this price has been determined for a particular connection point, the price is adjusted annually by the all capitals consumer price index (CPI).

8.2.2 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 SWIS. 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.