Appendix F.2

Tariff Structure Statement

Access arrangement

ERA Approved

31 March 2023

Tariff Structure Statement

To apply from 1 July 2023

Contents

1. Introduction

1.1 The structure of the TSS

The below table summarises the structure of this TSS:

Table 1.1: Structure of TSS

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Section 3	Allocation of target revenue to reference tariffs
Section 4	Stand-alone and avoidable cost
Section 5	Tariff structures
Section 6	Price setting for transmission reference services Price setting for new transmission nodes

Unless otherwise stated, all financial values in this document are expressed dollars of the day as of 30 June 2022.

2. Efficient cost target for distribution reference services

The efficient cost of providing each reference service has been calculated based on the value of the assets used in the provision of that service and the extent to which those assets are used, relative to its use by other reference services. The aggregation of the efficient cost target for all reference services is equal to the total efficient costs each year.

The network is made up of the transmission network (voltage 66 kV or higher) and the distribution network (voltage less than 66 kV). Connections to the transmission network use only the transmission network, whereas providing services to connections to the distribution network requires the use of both the transmission and distribution networks.

Distribution costs are therefore shared across distribution reference services only, whereas transmission costs are shared between distribution and transmission reference services.

Table 2.1 indicates how network costs are allocated between distribution and transmission reference services and the role played by the methodology used to estimate the efficient contribution.

Table 2.1: Efficient disaggregation of distribution and transmission costs to reference services

	Distribution reference services	Transmission reference services
Distribution costs	Determined by the efficient cost estimation methodology for distribution reference services.	Not relevant
Transmission costs	The transmission costs that are not allocated to transmission connections by the efficient cost estimation methodology for transmission reference services (section 6.1) are recovered from distribution reference services. These costs are shared across distribution connections as determined by the efficient cost estimation methodology for distribution reference services.	Determined by the efficient cost estimation methodology for transmission reference services (section 6.1).

The process to estimate the efficient cost target, i.e., the efficient cost estimation methodology, for distribution reference services is explained below.

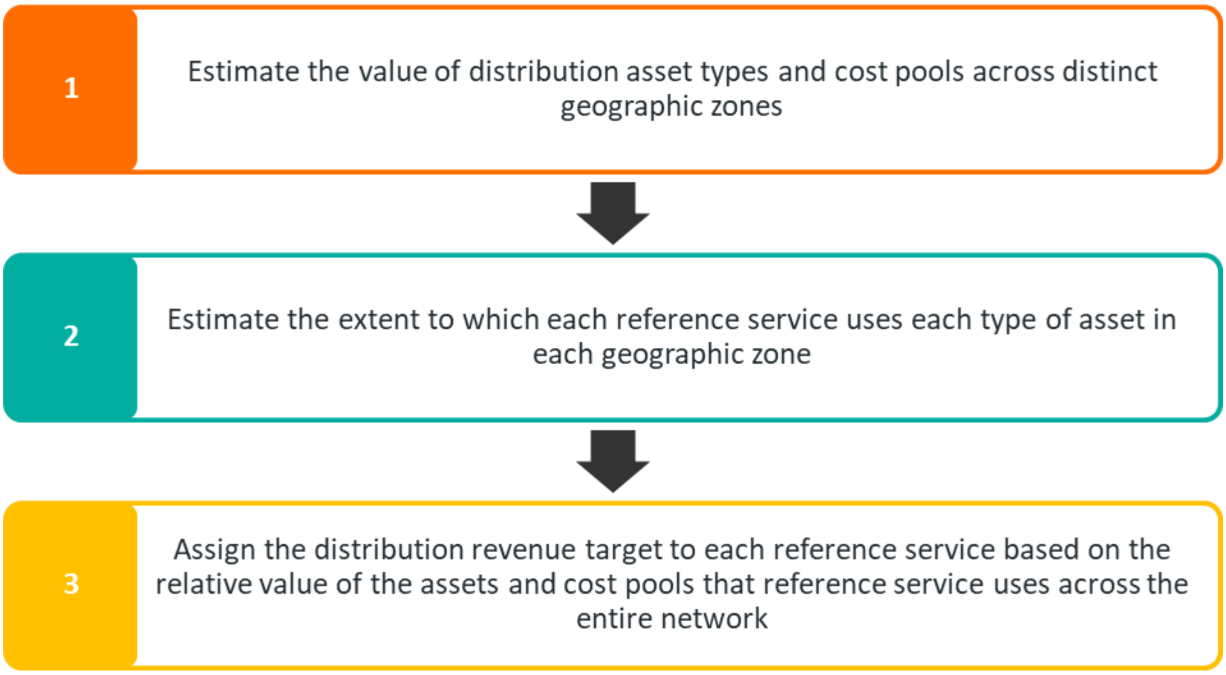
2.1 Contribution of total network costs to distribution reference tariffs

The total efficient cost of providing each reference service is calculated based on the value of the assets and services used by those end-users and the extent to which they use those assets and services, relative to end-users using other reference services.

The total efficient cost for each reference service, or the efficient cost target, is used to transition the revenue recovered from Western Power’s reference tariffs, consistent with the pricing objective of the Code, while managing bill impacts.

This process to estimate the efficient cost target for distribution reference services is summarised in Figure 2.1.

Figure 2.1: Efficient cost target estimation methodology for distribution reference services



Western Power's distribution network by is segmented by:

- six distribution asset types and 'cost pools',[1] relating to function and voltage level; and
- five geographic zones.

The cost pools and geographic zones are set out below and a description of each of the three steps illustrated in Figure 2.1 above.

2.1.1 Step 1 – estimating values for distribution asset types and cost pools across geographic areas

The first step of the methodology considers the relative value of each distribution cost pool or asset in the distribution network and the classification of these assets and cost pools into types and geographic area.

Distribution asset types and cost pools

Each distribution network asset can be classified to an asset type by reference to its function and the level of the network to which it relates. Similarly, the cost of providing administrative services for distribution reference services can be classified into a unique cost pool. The six distribution asset types and cost pools used in the distribution services cost allocation methodology are:

- distribution network transformers – which connects the high voltage distribution network to the low voltage distribution network;
- the high voltage distribution network;
- the low voltage distribution network;
- streetlight assets and services;
- metering assets and services; and

[1] The term 'cost pool' is used to refer to the cost of service or supply that is associated with providing a particular service or collection of services that provide similar functions or have similar characteristics.

- the administrative services cost pool.

Geographic zones

In a separate and distinct manner to the categorisation of assets by type, assets can also be categorised by the geographical area in which they are located. This is practically achieved by associating each network asset, regardless of asset type, to a particular zone substation.

The network is divided into five geographic zones in which the cost of providing references services is similar, due to their geographic location and/or the types of connections in these areas. In particular, each zone substation in the distribution network is assigned a unique geographic zone that reflects the cost structures of providing network services to the particular zone substation and to connections below the zone substation.

The five geographic zones defined for the distribution system are:

- the CBD zone – which is defined as an intense business area;
- the urban zone – which is defined as the uniformly and continuously settled areas of Perth that contain a mix of urban domestic, commercial, and industrial users;
- the rural zone – which is defined as those areas with a predominately rural or farming characteristics;
- the mining zone – which is defined as significant mining areas and are typically supplied with 33 kV feeders. Mining zones do not include the nearby towns or urban centres, which are either included in the rural or mixed zones; and
- the mixed zone – which is defined to capture areas that have a mixed user base that results in more than one dominant load base, e.g., mining, and rural loads or urban and rural loads.

In addition to unique cost structures, each geographic zone has a different mix of downstream connections and therefore provides a different combination of reference services to reflect these end-user mixes.

The categorisation of both network assets and reference services within each geographic zone therefore forms an integral part of understanding the efficient cost to serve each end-user.

Asset valuation

Western Power estimates the value of the distribution network by identifying the replacement value, mean replacement life and current equipment age for all assets across Western Power's distribution network in an asset register.

This asset register also provides information regarding the characteristics of the asset including, for example, the voltage level at which the asset is connected and the type of asset, i.e., poles, underground or overhead cabling. This information provides the basis by which the distribution network is broken down into the transformer, high voltage, and low voltage distribution asset types.[2]

There are two main assumptions that were used in the allocation of network assets to asset types, namely:

- the threshold between the low voltage and high voltage levels of the distribution network is 415 V, consistent with internal approaches to network planning; and
- assets that are allocated to multiple asset types, i.e., poles that support both low voltage and high voltage cables, are assumed to be split evenly between these two asset types.

[2] The asset valuation for streetlight and metering assets follows a different methodology described below.

Further, Western Power has used the replacement value of assets in the distribution cost allocation methodology. An alternate option would be to use the depreciated value of these assets. This approach has also been undertaken and had very little effect on the resulting valuations.

Each network asset is assigned an applicable zone substation determined by its location in the network. Across the entire distribution asset register, only five percent of the total value of assets have an indeterminate geographic location while all assets can be categorised into an asset type. As a result, Western Power has a high degree of visibility over the segmentation of the distribution network by asset type and geographic zone.

Table 2.2 presents the relative share of total network value by asset type (excluding streetlight, metering, and admin assets) and geographic location.

Table 2.2: Relative value of assets by asset type (excluding streetlight, metering, and admin assets) and geographic zone

Geographic zone	Low voltage assets	High voltage assets	Transformers	All assets
CBD	*0.5%*	*0.4%*	*0.2%*	***1.0%***
Urban	*23.8%*	*13.5%*	*2.8%*	***40.1%***
Rural	*4.0%*	*25.6%*	*1.3%*	***30.9%***
Mining	*0.0%*	*0.7%*	*0.0%*	***0.7%***
Mixed	*8.6%*	*17.0%*	*1.6%*	***27.3%***
All areas	***5.9%***	***57.3%***	***36.9%***	***100%***

Streetlight, metering, and admin

Streetlight, metering, and admin assets are not included in the asset types listed in Table 2.2. Their share of efficient costs is calculated separately and then the relative shares in Table 2.2 are adjusted downwards such that, when all asset types are combined, their relative shares sum to 100 per cent. The result of this process is presented in the next section which includes all asset types.

The total efficient costs of providing streetlight, metering and admin services are based on the share of the distribution revenue target that is directly attributable to each of these cost pools. That is, the cost allocation for streetlight, metering and admin services is not defined by determining the value of the types of assets in particular locations and then assigning a share of these costs to the streetlight and metering reference services relative to their use of those assets, as described in Table 2.2.

Rather, the cost allocation for streetlight, metering and admin reference services is determined using the building block approach, similar to that used in establishing target revenue for distribution and transmission services. The components to this building block approach for streetlight, metering and admin reference services are:

- return on assets – the product of the rate of return with the Regulated Asset Base (**RAB**);
- depreciation – based on the regulated value of the assets and the expected life of the assets;
- approved operating expenditure; and
- any indirect cost allocation – including a portion of overall tax and the recovery of deferred revenue.

The annual revenue requirement for streetlight, metering and admin services is not disaggregated by geographic zone in the building block approach. These cost pools are distributed among geographic zones using the relative allocation of the total value of Western Power's assets across these zones, as presented in Table 2.2.

Disaggregation of the annual revenue requirement by asset type and cost pool

The entire process of step 1 results in a disaggregation of the total annual revenue requirement into distinct asset types and cost pools, and subsequently, by geographic area within these categories.

In practice this involves removing the contribution of streetlight, metering and admin services from the total annual revenue requirement, before apportioning the remaining revenue requirement amongst the transformer, high voltage and low voltage asset classes by reference to their relative value of Western Power's total asset base. That is, the relative share of total asset value attributed to those assets determines the relative share of total revenue recovery attributed to the use of these assets.

2.1.2 Step 2 – estimating each reference service's relative use of asset types across geographic areas

In step 1, the relative value of each asset or cost pool for the distribution network is determined. In step 2, these relative values are translated from assets and cost pools to reference services using estimates for the use of system by end-users using each reference service in each geographic zone.

As mentioned above, zone substations in a particular geographic zone experience similar cost structures due to the similar load characteristics for the downstream connections. Conversely, zone substations in different geographic zones have a different combination of end-user types that make use of the network below that asset.

This implies that the assets in each geographic area make a unique contribution to total costs due to:

- the nature of the assets used in connecting that geographic area to the rest of the distribution network – as captured in step 1; and
- the mix of end-users using different distribution reference services in that geographic area – as captured in step 2.

Practically, step 2 involves breaking down the use of the network in each geographic area by the end-users for each reference service. There are three ways in which the relative use of the distribution network by a group of end-users can be calculated, namely the:

- contribution of end-users using each reference service to system-wide maximum demand, which incorporates the diversity in maximum demand for different types of reference services;[3]
- contribution of end-users using each reference service to total energy consumption; and
- total number of connections for each reference service.

Western Power allows for the relative use of each distribution asset type and cost pool by end-users using each reference service to be determined differently for different types of assets and different types of reference services. By way of example, the relative use of the administrative service cost pool is determined by the total number of connections for each reference service whereas the relative use of network assets, such as transformers and the high or low voltage networks, uses the contribution to

[3] Western Power is only able to observe the contribution to system-wide maximum demand for customers with interval meters, which is currently only a modest proportion of Western Power's total customer base. Using the collection of customers with interval meters Western Power is able to devise an average diversity factor for maximum demand for each reference service and apply this to the entire customer base using that reference service. This diversity factor captures the difference in the timing of maximum demand for different customers and facilitates Western Power's estimate for the contribution to maximum demand from the collection of customers using each reference service. Western Power envisions that this methodology will become more precise over time as the rollout of interval meters increases.

system-wide maximum demand. This ensures that costs with different characteristics are allocated in a manner that best suits these characteristics.

The use of network metrics for the distribution asset types and cost pools are:

- the contribution to system-wide maximum demand for transformers and high voltage distribution network assets;
- a combination of the contribution to system-wide maximum demand and total energy for low voltage distribution network assets, which is only applicable for low voltage connected reference services; and
- the total number of end-users for streetlight, metering and administrative services.

In step 1, the asset valuation occurs for transformers, high voltage and low voltage asset types. In order to establish the relative use of these assets by each reference service, adjustments are made to the relative maximum demand measurement for each reference service to reflect the different use of the levels of the network. By way of example:

- high voltage connections do not use the low voltage network and hence have zero contribution to maximum demand for these assets; and
- larger low voltage connections typically use less of the low voltage network because they are connected closer to transformers and so the contribution of larger low voltage business connections is weighted downwards relative to smaller low voltage residential connections.

To be consistent with the asset valuation data used in step 1, the use of system data is taken as the best estimate for the year in which the asset values were obtained, i.e., the 2021-22 financial year. This consistency ensures that the asset value register reflects the use of the network that is driving this network composition.

The relative contribution towards the use of the network for each customer class,[4] from the 2021-22 financial year, is presented in Table 2.3.

Table 2.3: Relative contribution to total network usage – 2021-22 financial year

Customer class	Number of connections	Maximum demand	Total energy consumed
Residential	74%	42%	39%
LV business - small	6%	26%	17%
Industrial	0%	32%	42%
Streetlights	19%	0%	1%
Unmetered	1%	0%	0%
Generators	0%	0%	0%
Grid-connected batteries	0%	0%	0%

Note: Some columns do not add to 100 per cent due to rounding.

By using actual use of system estimates that reflect the conditions at the time of the cost allocation calculation, the allocation of total efficient costs to each distribution reference service will capture the changing behaviour of different types of end-users. For instance, load shifting of residential end-users away

[4] Western Power previously disaggregated all distribution connected end-users into ten 'customer groups'. For AA5, Western Power has refined this categorisation so that all distribution connected end-users are classified into seven 'customer classes'.

from the traditional demand peak in the evening through use of distributed energy resources (**DER**) would result in a lower contribution to system maximum demand for these end-users. As a result, the allocation of costs to these end-users will decline to reflect their reduced contribution to the incursion of costs.

This relative use of system allocation between customer classes is used in conjunction with the disaggregation of the annual revenue requirement from step 1 to disaggregate the total efficient costs to an efficient target revenue for each customer class. Both of these processes incorporate the geographic dimension of the network to the efficient target revenue to end-users.

2.1.3 Step 3 – assign the distribution revenue target to distribution reference service

As stated above, this methodology calculates the total efficient cost of providing each reference service based on the value of the assets and services used by those end-users and the extent to which they use those assets and services, relative to end-users of other reference services.

The value of distribution assets and cost pools is determined in step 1 and the relative use of these assets and cost pools by each reference service is determined in step 2. In step 3, the total distribution revenue target is assigned to each distribution reference service to calculate the efficient cost target.

Because streetlight assets and services are only used by the streetlight distribution reference service, the entire streetlight cost of service is assigned to the streetlight reference service. This apportioning of total costs occurs separately to the assignment of the other costs to the other reference services.

The process by which total distribution target revenue is disaggregated to the efficient cost target for distribution reference services proceeds as follows:

- annual total distribution target revenue is determined, as approved by the ERA;
- non-reference service distribution revenue and the cost of service for streetlights are removed from the total distribution target revenue;
- this net distribution revenue is assigned to reference services using the relative allocation methodology described above; and
- the streetlight cost of service is assigned entirely to the streetlight reference service.

The result of this cost allocation methodology is for metering and administrative costs to be allocated on a per connection basis, consistent with their cost of service, and for the remaining distribution network costs to be allocated to each reference tariff based upon the relative value and use of each distribution network asset by end-users of each distribution reference service.

2.1.4 Transmission revenue recovered from distribution end-users

The cost allocation for transmission reference services, as discussed in the subsequent part of this section, details how a significant portion of transmission service revenue is to be recovered from distribution connections. This is because connections within the distribution network use the transmission network in order to consume electricity generated outside of the distribution network.

The pass through of transmission service revenue to distribution end-users is detailed at the zone substation level. That is, the result of the transmission cost allocation methodology is a value of transmission revenue to be recovered from distribution end-users located below each zone substation.

In a similar manner to how distribution network asset values are allocated across geographic zones in step 1, the pass through of transmission service revenue can be aggregated from the zone substation level to the geographic zone level. Table 2.4 presents an indicative breakdown of transmission service revenue by geographic zone.

Table 2.4: Relative value of transmission service revenue to be recovered from distribution end-users

Geographic zone	Proportion of total transmission service revenue
CBD	*5.0%*
Urban	*67.0%*
Rural	*8.5%*
Mining	*3.7%*
Mixed	*15.8%*

The disaggregation of the pass through of transmission service revenue among customer classes is consistent with the disaggregation of total distribution revenue to customer classes. That is, while distribution revenue is assigned to cost pools that are disaggregated by different measures of the relative use of the network, the combination of all cost pools gives rise to a relative share of total distribution revenue for each customer class.

This results in an allocation of transmission service revenue to distribution reference services that is consistent with the cost allocation methodology for distribution service revenue to distribution reference services. Therefore, the bundled (combined transmission and distribution) prices sent to distribution end-users is reflective of this new cost allocation methodology.

2.1.5 Resulting efficient cost target estimation

The efficient contribution of each reference service to total network costs can be prone to variation over time as use of the network changes relative to other reference services.

By way of example, residential end-users that install solar PV systems may reduce their reliance on current network assets by self-consuming their own generated electricity, and hence reduce their efficient cost target over time. However, Western Power may invest in new network assets that support two-way flows from these residential end-users that cause an offsetting increase in the efficient cost target for these end-users.

In order to combat these variations, Western Power undertakes a detailed estimation of efficient costs for each distribution reference service using historical network usage and network asset valuation data once at the start of AA5. This calculation of the efficient cost target then guides any transition of customer classes, or reference tariffs, over time.

3. Allocation of target revenue to reference tariffs

The previous section described how the efficient cost of providing each reference service is estimated.

This section describes how target revenue is allocated to each reference tariff and how prices are set so that the level of revenue expected to be recovered from each tariff:

- moves closer to the efficient cost target (as determined using the methodology in section 3);
- avoids unacceptable bill impacts on end-users; and
- is higher than the avoidable cost and lower than the standalone cost of providing the service.

This section also explains how prices are set for each reference tariff to recover the revenue allocated to each tariff, while avoiding unacceptable bill impacts.

Although the cost allocation methodology is applied at the reference tariff level, in practice it allocates revenue based on customer classes for which the total efficient cost of providing reference services is similar. These are:

- residential end-users;
- low voltage small business end-users;
- industrial end-users;
- streetlights and unmetered end-users; and
- generator end-users.

The efficient allocation for each of these customer classes is estimated as the sum of the efficient allocation of each reference tariff that comprises the customer class.

Western Power allocates revenue in this manner to manage interactions between the cost allocation methodology and the need to transition to efficient revenue allocations and historical pricing relationships. Specifically, the cost allocation methodology assumes that each reference tariff imposes different historical costs on the network and therefore has a unique efficient cost allocation.

However, Western Power's long-standing price approach has been to equivalently price exit and bi-directional reference services. It follows that reference tariffs that are intended to have the same prices may, according to the efficient allocations, require revenue allocations that move in opposite directions – breaking the nexus between their prices.

Allocating revenue instead to customer classes that have similar network use characteristics and tariff structures enables these pricing relationships to be preserved, while maintaining the ability, at an aggregate level, to transition the end-users in a customer class to their efficient revenue allocation (consistent with the requirements of the Code).

3.1 Three step allocation

Western Power has developed a revenue allocation methodology that is used to gradually transition each customer class to its efficient allocation throughout AA5 and beyond in a manner that proactively manages bill impacts. It comprises three steps:

- **step one – determine the baseline adjustment to revenue allocations.** This step involves changing the previous year's revenue per end-user (at the customer class level) by the percentage change in aggregate revenue per end-user. This is referred to as the 'baseline adjustment' to revenue allocations because it holds constant the relative position of the current and efficient cost allocation, taking account of the changes in total revenue, number of connections and volume. It therefore reflects no incremental effort to transition towards a more efficient allocation.

- **step two – transition to the efficient revenue allocation.** This step involves applying a further change to revenue per end-user – on top of the baseline adjustment – to transition the customer class towards its efficient allocation. The direction and scale of the change required to meet the efficient revenue allocation is determined by comparing the baseline adjustment revenue allocation with the efficient revenue allocation (as determined through Western Power's cost allocation methodology).
- **step three – set prices to recover allocated revenue.** This step involves deriving prices for various components of each reference tariff such that the revenue allocated to the relevant customer class is recovered. Western Power applies a pricing approach that seeks to rebalance Western Power's recovered revenue from variable charges to fixed charges, while managing bill impacts and promoting the uptake of Western Power's new, efficiently priced reference tariffs.

The requirement for each reference tariff to reflect the efficient costs of providing those reference services is a new addition to the Code.[5] A consequence of this is that the baseline adjustment revenue allocations may differ substantially from the efficient allocation in each year, meaning significant price changes would be required to transition each customer class directly to its efficient allocation. When an increase in the revenue allocation is required for a customer class to transition to its efficient allocation, to manage bill impacts, Western Power endeavours to limit the increase in revenue per end-user to two per cent on top of the baseline adjustment.

As the first price list for AA5 does not commence until the second year of AA5 (FY24) it could therefore be characterised as a transitional year for the cost allocation methodology, since its focus is predominantly on managing bill impacts, rather than on transitioning to more efficient cost allocations using Western Power's three-step methodology, while also managing bill impacts.

The three-stage revenue allocation methodology is described in further detail below.

3.2 Step 1: Baseline adjustment

The first step in the cost allocation methodology is to calculate the change in average revenue per end-user in the previous year that is required – across all end-users – to account for:

- changes in Western Power's ERA-approved revenue target; and
- changes in the number of connections from year-to-year.

This is referred to as the 'baseline adjustment', i.e., it is a baseline, average change in price that will allow Western Power to recover the ERA-approved revenue target, without any consideration given to improving the efficiency of the cost allocation.

Adjusting the average revenue recovered from each customer class by this percentage will allow Western Power to recover the approved revenue target. This is an equitable first step, since it applies to all end-users evenly and creates a common baseline from which to apply transitional considerations, i.e., to transition revenue recovered from each group of end-users towards an efficient level and manage bill impacts, which is addressed in step two.

Table 3.1 presents the forecast number of connections in each customer class over AA5, which shows that the number of connections is growing across nearly all customer classes.

5 The Code previously required that the total of all tariffs reflected the efficient costs of providing reference services.

Table 3.1: Forecast distribution connection numbers by customer class over AA5

Customer class	2021-22	2022-23	2023-24	2024-25	2025-26	2026-27	Annualised growth rate over AA5
Residential	*1,085,063*	*1,093,903*	*1,103,159*	*1,112,494*	*1,122,457*	*1,133,184*	*0.87%*
LV business – small	*89,805*	*94,989*	*100,641*	*107,211*	*113,779*	*119,963*	*5.96%*
Industrial	*4,223*	*4,386*	*4,434*	*4,485*	*4,537*	*4,590*	*1.68%*
Streetlights	*278,067*	*288,636*	*293,180*	*297,685*	*302,467*	*307,357*	*2.02%*
Unmetered	*18,698*	*19,460*	*19,811*	*20,162*	*20,513*	*20,864*	*2.22%*
Generators	*25*	*25*	*25*	*25*	*25*	*25*	*0.00%*

3.3 Step 2: Transitioning to a more efficient allocation

Having established the change in average revenue per end-user that will enable Western Power to recover its approved revenue target – with no incremental improvements in efficiency – the second step is to transition the revenue recovered from each customer class towards the efficient level (as estimated using the methodology described in section 3), while managing bill impacts on end-users.

Western Power evaluates these transitional decisions relative to the outcome of the baseline adjustment in step one. This means that, in the context of a downwards baseline adjustment, a customer class from which more revenue needs to be recovered may experience a slower decline in average prices, rather than a total increase, ie, the net effect of a downwards baseline adjustment and an upwards efficiency adjustment may still be a total decrease in prices.

Table 3.2 illustrates the direction in which the revenue recovered from each customer class needs to shift over AA5 to move closer to the efficient cost target that is described in section 2, after the baseline adjustment.

Table 3.2: Direction of required transition towards efficient cost allocation over AA5

Customer class	Direction of transition to efficient level of cost recovery, after baseline adjustment in step one
Residential	Decrease
LV business – small	Increase
Industrial	Decrease
Streetlights and unmetered	Increase
Generators	Decrease

In practice, Western Power evaluates the change in average revenue per end-user that would be required to achieve the efficient cost target, and then transitions towards that efficient allocation while managing the effects on end-users' bills.

There are strong interrelationships between the transitional decisions for each customer class, i.e., a decrease in the revenue allocation for a customer class from which Western Power recovers a lot of revenue (e.g., residential end-users), can require larger increases in revenue allocation for smaller customer classes to ensure that the approved revenue target is recovered in aggregate.

Western Power allocates revenue between customer classes so that the average revenue per end-user recovered from each customer class so that, after the baseline adjustment, the revenue recovered (or the cost allocation) moves closer to the efficient cost target.

Having allocated target revenue to each customer class, Western Power then allocates target revenue to the individual reference tariffs that comprise each customer class. Since each customer class comprises end-users that impose similar costs on the network, Western Power allocates revenue to each reference tariff to ensure that it recovers a similar level of revenue from end-users that impose similar costs on the network.

As required by the Code, Western Power also ensures that the level of revenue that it expects to recover from each reference tariff lies on or between:[6]

> a) *an upper bound representing the stand-alone cost of service provision for customers to whom or in respect of whom that reference tariff applies; and*
>
> b) *a lower bound representing the avoidable cost of not serving the customers to whom or in respect of whom that reference tariff applies:*

Western Power considers that full compliance with this provision would give rise to significant increases in fixed charges. In light of feedback from users and end-use customers, Western Power has limited the increases in fixed charges and therefore recovers more costs from variable charges than is required by clause 7.6 of the Code. Western Power will endeavour to more fully comply with this requirement in the future, while managing bill impacts.

[6] The Code, clause 7.3(d).

3.4 Step 3: Setting prices to recover allocated revenue

Once the revenue allocation is set for each customer class using the baseline adjustment and efficiency transition in step one and two, Western Power then derives prices for each charging component that comprises each individual tariff, such that it expect to recover the target revenue (or costs) allocated to each customer class. Our price setting process is guided by four overarching objectives:

- rebalance our revenue recovery towards fixed charges and away from variable charges to improve the efficiency of our tariffs, and consistent with clauses 7.3H(c) and 7.6 of the Code;
- encourage the uptake of our new reference tariffs to promote efficient use of our network;
- achieve and retain specific, relative relationships between time-of-use charges, e.g.:
  - to set the shoulder price equal to approximately 1.3 times the off-peak price; and
  - to set the peak price equal to approximately two times the shoulder price; and
- manage bill impacts in the pursuit of the above objectives.

The practical application of this approach is that for reference tariffs:

- with reducing revenue per end-user, Western Power decreases variable charges in the first instance by a constant proportion to retain the relative relationship between those prices; and
- with increasing revenue per end-user, Western Power increases fixed charges and then increases variable charges thereafter.

Prices are also set to avoid arbitrage opportunities between residential reference tariffs for end-users with similar usage patterns. This reflects the fact that residential end-users should contribute to recovering the network costs based on their network usage, irrespective of which reference tariff they are assigned to by their retailer.

4. Stand-alone and avoidable cost

Clause 7.3D of the Code requires that the revenue expected to be recovered from each reference tariff must lie on or between:

a) *an upper bound representing the stand-alone cost of service provision for customers to whom or in respect of whom the reference tariff applies; and*

b) *a lower bound representing the avoidable cost of not serving the customers to whom or in respect of whom the reference tariff applies.*

4.1 Economic concepts

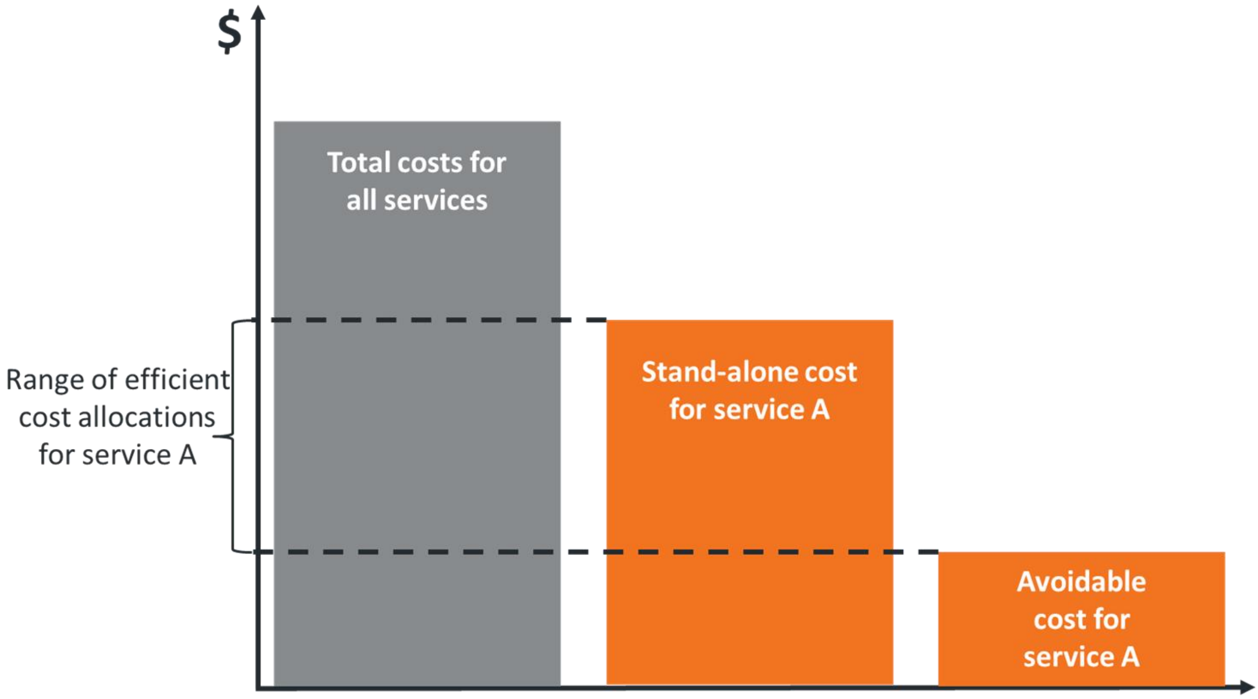
The economic concepts of stand-alone and avoidable cost reflect the principle that the amount recovered from users of any one service in a group of services using shared assets should be:

- no more than the efficient cost of providing that service alone (the stand-alone cost) – if those end-users were charged more than the stand-alone cost, then it would be hypothetically possible for them to pay an alternative provider to provide the service at a lower cost; and
- no less than the additional costs directly incurred to provide the service (the avoidable cost) – if those end-users were charged less than the avoidable cost then the business would not be recovering the costs incurred to supply the end-users, and the shortfall in revenue would have to be recovered from other end-users.

The recovery of costs within these bounds will ensure that each reference service is priced no higher than the level at which it may be profitable for end-users to bypass the service, and no less than the level at which one service is subsidising the provision of any others.

It follows that any allocation of costs within these bounds is efficient, as shown in the indicative example provided in Figure 4.1. The ultimate allocation of costs within these bounds involves a matter of equity between end-users and a degree of judgement by subject matter experts.

Figure 4.1: The range of efficient cost allocations for a particular service



Importantly, a cross-subsidy arises only when the costs recovered from users of a particular service fall outside the bounds established by the stand-alone cost (upper bound) and avoidable cost (lower bound) of that particular service.

4.2 Estimation

Both stand-alone and avoidable costs, as defined in the Code, relate to a specific portion of the 'approved total costs' as part of the annual revenue requirement. This implies that the estimation of these concepts involves apportioning approved total costs, rather than determining or calculating specific costs or values.

Western Power notes that as each reference service is allocated both distribution and transmission costs, stand-alone and avoidable costs also contain both distribution and transmission components.

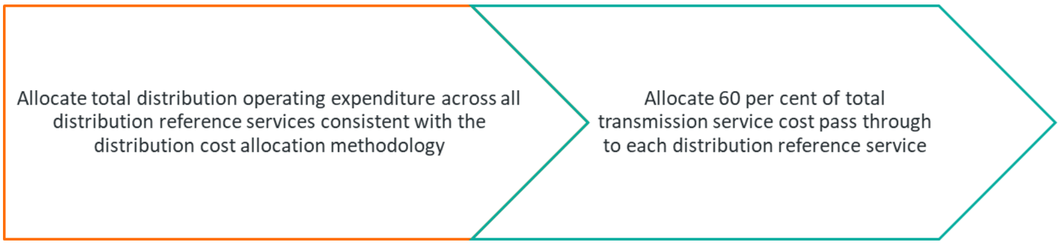
The estimation process for stand-alone and avoidable costs is discussed separately, commencing with the process for avoidable cost.

4.2.1 Avoidable cost

The terms 'incremental cost' and 'avoidable cost' are often interchangeable in the context of network pricing principles. In fact, the Code refers to 'avoidable cost' in clause 7.3D(b) yet defines the 'incremental cost of service provision' as the costs that would be 'avoided' if the services were not provided. It follows that the interpretation of avoidable cost in clause 7.3D(b) should remain consistent with definition of incremental cost from the Code.

The process for estimating avoidable cost for distribution reference services is presented in Figure 4.2.

Figure 4.2: Estimation of avoidable costs for distribution reference services



As defined in the Code, the incremental cost of a network service considers the portion of approved total costs that would be avoided during the specified period of time if that particular network service was not provided. In any particular year, the only cost that would be avoided from not providing a network service is the operating expenditure allocated to that network service. This is because the majority of approved total costs are fixed and related to the RAB, in which case they are not avoided when only a single service is not provided. Therefore, operating expenditure is the only component of total cost that is apportioned to avoidable cost.

As described in sections 2 and 3, Western Power has developed a methodology for allocating total distribution costs to distribution reference services. The avoidable cost methodology assumes that operating expenditure is allocated to distribution reference services in the same proportion that total distribution costs are allocated. Allocating total operating expenditure for distribution services provides an estimate for the distribution component to the avoidable cost for distribution reference services.

Avoidable costs for distribution reference services must also consider the transmission component to the service. Consistent with the approved approach used in previous Access Arrangements, Western Power assumes that 60 per cent of the transmission revenue recovered from each distribution reference service is associated with variable costs on the transmission network and are hence avoidable if the service is not provided.

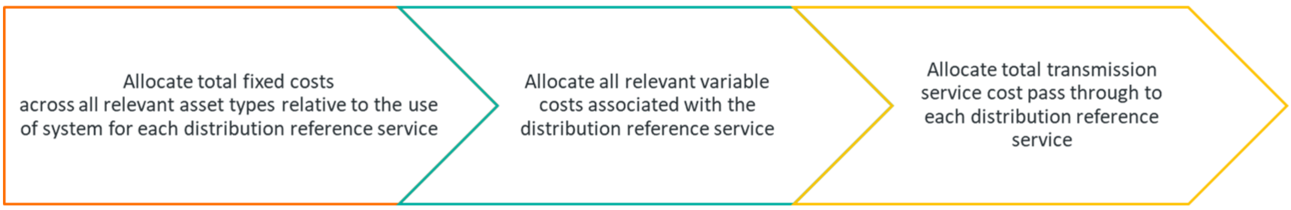
With regards to transmission connections, many components of total operating expenditure will still be necessary if certain services are not provided. In particular, the only component of total transmission operating expenditure that is avoidable is operating expenditure associated with network operations activities.

The forecast of total network operations expenditure each year is split evenly between loads and generators to obtain the avoided cost for each transmission reference tariff. This methodology is consistent with the approved approach used in previous Access Arrangements.

4.2.2 Stand-alone cost

The process for estimating stand-alone cost for distribution reference services is presented in Figure 4.3.

Figure 4.3: Estimation of stand-alone costs for distribution reference services



As described in sections 2 and 3, Western Power has developed a cost allocation methodology for distribution reference services that allocates the total distribution service cost across distribution asset types and distribution reference services. In addition, the transmission costs that are passed through to distribution reference services also follows a similar allocation methodology.

The distribution asset types in the distribution cost allocation methodology are assumed to have a further allocation of fixed and variable components. The proportion of fixed and variable costs for each asset type is presented in Table 4.1.

Table 4.1: Fixed and variable relative components to total costs for distribution system assets

Distribution asset type	Relative fixed cost component	Relative variable cost component
Transformers	*100%*	*0%*
High voltage assets	*40%*	*60%*
Low voltage assets	*40%*	*60%*
Streetlights	*100%*	*0%*
Metering	*0%*	*100%*

To determine the component of stand-alone cost attributable to distribution services, each distribution reference service is allocated:

- a share of all fixed costs for all relevant distribution asset types, determined by the relative use of system by end-users of that reference service; and
- the variable costs for all relevant distribution asset types allocated to that particular distribution reference service only.

The transmission service component to stand-alone costs for distribution reference services is the total pass through of transmission revenue allocated to that particular reference service.

With regards to transmission connections, the stand-alone cost of service is equal to total transmission costs less the costs that are avoided when the service is not provided. This allocation applies to both loads and generators on the transmission system.

As such, the stand-alone cost for all transmission reference services is total transmission costs less the avoidable cost for that transmission reference service. This methodology is consistent with the approved approach used in previous Access Arrangements.

5. Tariff structures

The following table details which reference tariff is applicable to each of the reference services.

Table 5.1: Reference services and applicable tariffs

Reference service	Reference tariff
A1 – Anytime Energy (Residential) Exit Service	RT1
A2 – Anytime Energy (Business) Exit Service	RT2
A3 – Time of Use Energy (Residential) Exit Service	RT3
A4 – Time of Use Energy (Business) Exit Service	RT4
A5 – High Voltage Metered Demand Exit Service C5 – High Voltage Metered Demand Bi-directional Service	RT5
A6 – Low Voltage Metered Demand Exit Service C6 – Low Voltage Metered Demand Bi-directional Service	RT6
A7 – High Voltage Contract Maximum Demand Exit Service C7 – High Voltage Contract Maximum Demand Bi-directional Service	RT7
A8 – Low Voltage Contract Maximum Demand Exit Service C8 – Low Voltage Contract Maximum Demand Bi-directional Service	RT8
A9 – Streetlighting Exit Service	RT9
A10 – Unmetered Supplies Exit Service	RT10
A11 – Transmission Exit Service	TRT1
B1 – Distribution Entry Service	RT11
B2 – Transmission Entry Service	TRT2
B3 – Entry Service Facilitating a Distributed Generation or Other Non-NetworkSolution	RT23
C1 – Anytime Energy (Residential) Bi-directional Service	RT13
C2 – Anytime Energy (Business) Bi-directional Service	RT14
C3 – Time of Use (Residential) Bi-directional Service	RT15
C4 – Time of Use (Business) Bi-directional Service	RT16
A12 – 3 Part Time of Use Energy (Residential) Exit Service C9 – 3 Part Time of Use Energy (Residential) Bi-directional Service	RT17
A13 – 3 Part Time of Use Energy (Business) Exit Service C10 – 3 Part Time of Use Energy (Business) Bi-directional Service	RT18

Reference service	Reference tariff
A14 – 3 Part Time of Use Demand (Residential) Exit Service C11 – 3 Part Time of Use Demand (Residential) Bi-directional Service	RT19
A15 – 3 Part Time of Use Demand (Business) Exit Service C12 – 3 Part Time of Use Demand (Business) Bi-directional Service	RT20
A16 – Multi Part Time of Use Energy (Residential) Exit Service C13 – Multi Part Time of Use Energy (Residential) Bi-directional Service	RT21
A17 – Multi Part Time of Use Energy (Business) Exit Service C14 – Multi Part Time of Use Energy (Business) Bi-directional Service	RT22
C15 – Bi-directional Service Facilitating a Distributed Generation or Other Non-Network Solution	RT24
D1 – Supply Abolishment Service	RT25
D2 – Capacity Allocation Service	NA[7]
D6 – Remote Load / Inverter Control Service	RT26
D8 – Remote De-energise Service	RT28
D9 – Remote Re-energise Service	RT29
D10 – Streetlight LED Replacement Service	RT30
D11 – Site Visit to Support Remote Re-energise Service	RT31
D12 – Manual De-energise Service	RT32
D13 – Manual Re-energise Service	RT33
A19 – Super Off-peak Energy (Business) Exit Service C17 – Super Off-peak Energy (Business) Bi-directional Service	RT34
A18 – Super Off-peak Energy (Residential) Exit Service C16 – Super Off-peak Energy (Residential) Exit Service	RT35
A21 – Super Off-peak Demand (Business) Exit Service C19 – Super Off-peak Demand (Business) Bi-directional Service	RT36
A20 – Super Off-peak Demand (Residential) Exit Service C18 – Super Off-peak Demand (Residential) Bi-directional Service	RT37
C22 – Transmission Storage Service	TRT3
C23 – Low Voltage Distribution Storage Service	RT38
C24 – High Voltage Distribution Storage Service	RT39

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

Reference service	Reference tariff
A22 – Low Voltage Electric Vehicle Charging Exit Service C20 – Low Voltage Electric Vehicle Charging Bi-directional Service	RT40
A23 – High Voltage Electric Vehicle Charging Exit Service C21 – High Voltage Electric Vehicle Charging Bi-directional Service	RT41

Any existing reference tariff that is superseded by a new reference tariff is classified as a 'transitional' reference tariff.

The existing end-users will be provided with the transitional reference tariff if and only if:

- the services were provided at the relevant connection points at the commencement of AA5, and
- those services continue from the commencement of AA5.

However, from the commencement of AA5, the transitional reference tariff will be closed for new nominations. Existing connection points under those reference tariffs will transition to the new time of use reference tariffs over the course of AA5.

Table 5.2 provides a high level indication for the structure of each reference tariff offered by Western Power.

Table 5.2: Summary of tariff structures

TARIFF	TARIFF COMPONENTS																					
	Closed to New Entrants	Tx and Dx Component	Fixed Component (c/day)	Anytime Energy (c/kWh)	On-Peak Energy (c/kWh)	Shoulder Energy (c/kWh)	Off-Peak Energy (c/kWh)	Overnight Energy (c/kWh)	Super Off-Peak Energy (c/kWh)	Metered Demand (c/kVA/day) or c/kW/day)	Export charge (c/kWh)	Annual Metered Demand	Off-Peak Discount Factor (%)	CMD/DSOC	Demand/ Length for ATMD > 1,000 kVA	Connection Component (c/kW/day)	Use of System Component (c/kW/day)	Common Service Component (c/kW/day)	Excess Network Usage	Fixed Metering Component (c/day)	Administration Component (c/day)	Charge Per Request ($)
RT1 – Anytime Energy (Residential)	No	✓	✓	✓																✓		
RT2 – Anytime Energy (Business)	No	✓	✓	✓																✓		
RT3 - Time of Use Energy (Residential)	Yes	✓	✓		✓		✓													✓		
RT4 - Time of Use Energy (Business)	Yes	✓	✓		✓		✓													✓		

TARIFF	TARIFF COMPONENTS																					
	Closed to New Entrants	Tx and Dx Component	Fixed Component (c/day)	Anytime Energy (c/kWh)	On-Peak Energy (c/kWh)	Shoulder Energy (c/kWh)	Off-Peak Energy (c/kWh)	Overnight Energy (c/kWh)	Super Off-Peak Energy (c/kWh)	Metered Demand (c/kVA/day) or c/kW/day	Export charge (c/kWh)	Annual Metered Demand	Off-Peak Discount Factor (%)	CMD/DSOC	Demand/ Length for ATMD > 1,000 kVA	Connection Component (c/kW/day)	Use of System Component (c/kW/day)	Common Service Component (c/kW/day)	Excess Network Usage	Fixed Metering Component (c/day)	Administration Component (c/day)	Charge Per Request ($)
RT5 - HV Metered Demand	No	✓	✓							✓		✓	✓		✓					✓		
RT6 - LV Metered Demand	No	✓	✓							✓		✓	✓		✓					✓		
RT7 - HV CMD	No	✓	✓											✓	✓				✓	✓	✓	
RT8 - LV CMD	No	✓	✓											✓	✓				✓	✓	✓	
RT9 - Streetlighting	No	✓	✓	✓																		
RT10 – Unmetered Supplies	No	✓	✓	✓																		
RT11 - Distribution Entry	No	✓												✓	✓	✓	✓		✓	✓		
RT13 – Anytime Energy (Residential) Bi-directional	No	✓	✓	✓																✓		
RT14 – Anytime Energy (Business) Bi-directional	No	✓	✓	✓																✓		
RT15 – Time of Use (Residential) Bi-directional	Yes	✓	✓		✓		✓													✓		
RT16 – Time of Use (Business) Bi-directional	Yes	✓	✓		✓		✓													✓		
RT17 –Time of Use Energy (Residential)	Yes	✓	✓		✓	✓	✓													✓		
RT18 –Time of Use Energy (Business)	Yes	✓	✓		✓	✓	✓													✓		

TARIFF	TARIFF COMPONENTS																					
	Closed to New Entrants	Tx and Dx Component	Fixed Component (c/day)	Anytime Energy (c/kWh)	On-Peak Energy (c/kWh)	Shoulder Energy (c/kWh)	Off-Peak Energy (c/kWh)	Overnight Energy (c/kWh)	Super Off-Peak Energy (c/kWh)	Metered Demand (c/kVA/day) or c/kW/day	Export charge (c/kWh)	Annual Metered Demand	Off-Peak Discount Factor (%)	CMD/DSOC	Demand/ Length for ATMD > 1,000 kVA	Connection Component (c/kW/day)	Use of System Component (c/kW/day)	Common Service Component (c/kW/day)	Excess Network Usage	Fixed Metering Component (c/day)	Administration Component (c/day)	Charge Per Request ($)
RT19 –Time of Use Demand (Residential)	Yes	✓	✓		✓	✓	✓			✓										✓		
RT20 –Time of Use Demand (Business)	Yes	✓	✓		✓	✓	✓			✓										✓		
RT21 – Multi Part Time of Use Energy (Residential)	Yes	✓	✓		✓	✓	✓	✓												✓		
RT22 – Multi Part Time of Use Energy (Business)	Yes	✓	✓		✓	✓	✓	✓	✓											✓		
RT34 – Super Off-peak Energy (Business) – new	No	✓	✓		✓	✓	✓		✓											✓		
RT35 – Super Off-peak Energy (Residential) – new	No	✓	✓		✓	✓	✓		✓											✓		
RT36 – Super Off-peak Demand (Business) – new	No	✓	✓		✓	✓	✓		✓	✓										✓		
RT37 – Super Off-peak Demand (Residential) - new	No	✓	✓		✓	✓	✓		✓	✓										✓		
RT38 – Low Voltage Distribution Storage - new	No	✓	✓		✓	✓	✓		✓		✓									✓		
RT39 – High Voltage Distribution Storage - new	No	✓	✓		✓	✓	✓		✓		✓									✓		
RT40 – Low Voltage Electric Vehicle - new	No	✓	✓		✓ *	✓ *	✓ *		✓ *	✓ *										✓		

TARIFF	TARIFF COMPONENTS																				
	Closed to New Entrants	Tx and Dx Component	Fixed Component (c/day)	Anytime Energy (c/kWh)	On-Peak Energy (c/kWh)	Shoulder Energy (c/kWh)	Off-Peak Energy (c/kWh)	Overnight Energy (c/kWh)	Super Off-Peak Energy (c/kWh)	Metered Demand (c/kVA/day) or c/kW/day)	Export charge (c/kWh)	Annual Metered Demand	Off-Peak Discount Factor (%)	CMD/DSOC	Demand/ Length for ATMD > 1,000 kVA	Connection Component (c/kW/day)	Use of System Component (c/kW/day)	Common Service Component (c/kW/day)	Excess Network Usage	Fixed Metering Component (c/day)	Administration Component (c/day)	Charge Per Request ($)
RT41 – High Voltage Electric Vehicle - new	No	✓	✓		✓ *	✓ *	✓ *		✓ *	✓ *										✓		
RT23 – Entry Service Facilitating a Distributed Generation or Other Non-Network Solution	No																					✓
RT24 – Bi-directional Service Facilitating a Distributed Generation or Other Non-Network Solution	No																					✓
RT25 – Supply Abolishment	No																					✓
RT26 – Remote Load/Inverter Control	No																					✓
RT28 – Remote De-energise	No																					✓
RT29 – Remote Re-energise	No																					✓
RT30 – Streetlight LED Replacement	No																					✓
RT31 – Site Visit to support Remote Re-energise - new	No																					✓
RT32 – Manual De-energise - new	No																					✓
RT33 – Manual Re-energise - new	No																					✓

TARIFF	TARIFF COMPONENTS																				
	Closed to New Entrants	Tx and Dx Component	Fixed Component (c/day)	Anytime Energy (c/kWh)	On-Peak Energy (c/kWh)	Shoulder Energy (c/kWh)	Off-Peak Energy (c/kWh)	Overnight Energy (c/kWh)	Super Off-Peak Energy (c/kWh)	Metered Demand (c/kVA/day) or c/kW/day)	Export charge (c/kWh)	Annual Metered Demand	Off-Peak Discount Factor (%)	CMD/DSOC	Demand/ Length for ATMD > 1,000 kVA	Connection Component (c/kW/day)	Use of System Component (c/kW/day)	Common Service Component (c/kW/day)	Excess Network Usage	Fixed Metering Component (c/day)	Administration Component (c/day)	Charge Per Request ($)
TRT1 – Transmission Exit	No		✓											✓			✓	✓	✓	✓		

**Indicates a sliding scale of charges, based on utilisation*

A detailed explanation of the structure of each transmission and distribution reference tariff is set out below. For the purpose of this description, reference tariffs have been grouped as follows:

- transmission reference services;
- distribution reference services for residential end-users;
- distribution reference services for small and medium business end-users;
- distribution reference services for large business end-users; and
- other distribution reference services.

5.1 Transmission reference services

5.1.1 Transmission load tariff (TRT1)

TRT1 consists of:

- a user-specific charge that is to be an amount per day which reflects the costs to Western Power of providing the Connection Assets under an Access Contract, which may consist of capital and non-capital costs;
- a variable use of system charge calculated by multiplying the applicable use of system price or where there is no applicable use of system price for the exit point, the price calculated by Western Power in accordance with the policy for setting prices for new transmission nodes by the contracted maximum demand (CMD) at the exit point (expressed in kW);
- a variable common service charge calculated by multiplying the common service price by the CMD at the exit point (expressed in kW);
- a variable control system service charge calculated by multiplying the control system service price by the CMD at the exit point (expressed in kW);
- a fixed metering charge per revenue meter which is payable each day; and
- excess network usage charges if applicable.

An excess network usage charge (ENUC) charge applies to this tariff where the peak half-hourly demand exceeds the nominated CMD during the billing period of the load.

The ENUC is calculated by applying a factor to the excess usage as follows:

ENUC = ENUM * (PD – CMD) * (UOS + CON + CS + CSS) / CMD

Where

ENUM	is the Excess network usage multiplier factor;
PD	is the peak half-hourly demand during the billing period of the load (expressed in kW);
CMD	is the nominated CMD for the billing period of the load (expressed in kW);
UOS	is the applicable variable use of system charge for the billing period for the nominated CMD;
CON	is the applicable user-specific charge for the billing period;
CS	is the applicable variable common service charge for the billing period for the nominated CMD;
CSS	is the applicable variable control system service charge for the billing period for the nominated CMD;

The ENUC does not include the metering components of the tariff.

If the connection point is subject to the Capacity (Swap) Allocation (Business) Exit Service, for the purposes of the ENUC calculation above the CMD is the total contracted capacity allocated to the connection point from time to time pursuant to the capacity allocation arrangement.

5.1.2 Transmission generator tariff (TRT2)

TRT2 consists of:

- a user-specific charge that is to be an amount per day which reflects the costs to Western Power of providing the Connection Assets under an Access Contract, which may consist of capital and non-capital costs;
- a variable use of system charge calculated by multiplying the applicable use of system price or where there is no applicable use of system price in Table 41 for the entry point, the price calculated by Western Power in accordance with the policy for price setting for new transmission nodes by the declared sent-out capacity (DSOC) at the entry point (expressed in kW);
- a variable control system service charge calculated by multiplying the control system service price by the nameplate output of the generator at the entry point (expressed in kW);
- a fixed metering charge per revenue meter which is payable each day; and
- excess network usage charges (if applicable).

An excess network usage charge (ENUC) applies to this tariff where the peak half-hourly demand exceeds the nominated DSOC during the billing period except where Western Power deems the export of power in excess of DSOC was required for power system reliability and security purposes.

The excess network usage charge (ENUC) is calculated by applying a factor to the excess usage as follows:

ENUC = ENUM * (PD – DSOC) * (UOS + CON + CSS) / DSOC

Where:

ENUM	is the Excess network usage multiplier factor;
PD	is the peak half-hourly demand during the billing period (expressed in kW);
DSOC	is the nominated DSOC for the billing period (expressed in kW);
UOS	is the applicable variable use of system charge for the billing period for the nominated DSOC;
CON	is the applicable user-specific charge for the billing period; and
CSS	is the applicable variable control system service charge for the billing period.

The ENUC does not include the metering components of the tariff.

5.1.3 Transmission storage service tariff (TRT3)

TRT3 consists of:

- A user-specific charge that is to be an amount per day which reflects the costs to Western Power of providing the Connection Assets under an Access Contract, which may consist of capital and non-capital costs.
- A variable use of system charge calculated by multiplying the applicable use of system price or where the is no applicable use of system price for the entry point, the price calculated by Western Power in accordance with policy for setting prices for new transmission nodes by the declared sent-out capacity (DSOC) at the entry point (expressed in kW).
- A variable control system service charge calculated by multiplying the control system service price by the nameplate output of the generator at the entry point (expressed in kW).
- A fixed metering charge pre revenue meter which is payable each day.
- Excess network usage charges.

Excess network usage charges apply to this tariff where the peak half-hourly demand exceeds the nominated DSOC during the billing period except where Western Power deems the export of power in excess of DSOC was required for power system reliability and security purposes.

The excess network usage charge (ENUC) is calculated by applying a factor to the excess usage as follows:

ENUC = ENUM * (PD – DSOC) * (UOS + CON + CSS) / DSOC

Where

ENUM is the Excess network usage multiplier factor.

PD is the peak half-hourly demand during the billing period (expressed in kW)

DSOC is the nominated DSOC for the billing period (expressed in kW)

UOS is the applicable variable use of system charge for the billing period for the nominated DSOC

CON is the applicable user-specific charge for the billing period

CSS is the applicable variable control system service charge for the billing period.

5.2 Distribution reference services – residential end-users

5.2.1 Anytime energy tariffs (RT1 and RT13)

There are two anytime energy tariffs, one for residential end-users that only import energy from the network (RT1) and another for residential end-users that both import and export energy from the network (RT13), i.e., that use a bi-directional service. The structure of these two tariffs is the same.

RT1 and RT2 consist of:

- a fixed use of system charge which is payable each day;
- a variable use of system charge calculated by multiplying the energy price by the quantity of electricity consumed at an exit point (expressed in kWh); and
- a fixed metering charge per revenue meter which is payable each day.

5.2.2 Time of use energy tariffs (RT3 and RT15)

These are transitional tariffs.

RT3 was for residential end-users that only import energy from the network and RT15 was for end-users that both import and export energy from the network. The structure and pricing of these two tariffs is the same.

RT3 and RT15 consist of:

- a fixed use of system charge which is payable each day;
- an on-peak use of system variable charge calculated by multiplying the on-peak energy price by the quantity of on-peak electricity consumed at an exit point (expressed in kWh);
- an off-peak use of system variable charge calculated by multiplying the off-peak energy price by the quantity of off-peak electricity consumed at an exit point (expressed in kWh); and
- a fixed metering charge per revenue meter which is payable each day.

The on- and off-peak periods applicable to RT3 and RT15 are defined in Table 5.3 (all times are Western Standard Time (WST)).

Table 5.3: Definition of charging windows for RT3 and RT15

Monday – Friday (includes public holidays)			Saturday – Sunday (excludes public holidays)
Off-peak	**On-Peak**	**Off-Peak**	**Off-Peak**
12:00am – 7:00am	7:00am – 9:00pm	9:00pm – 12:00am	All times

5.2.3 Three part time of use energy tariff (RT17)

This is a transitional tariff.

RT17 was available to residential end-users that only import energy from the network and to those that both import and export energy from the network.

RT17 consists of:

- a fixed use of system charge which is payable each day;
- an on-peak use of system variable charge calculated by multiplying the on-peak energy price by the quantity of on-peak electricity consumed at the connection point (expressed in kWh);
- a shoulder use of system variable charge calculated by multiplying the shoulder energy price by the quantity of shoulder period electricity consumed at the connection point (expressed in kWh);
- an off-peak use of system variable charge calculated by multiplying the off-peak energy price by the quantity of off-peak electricity consumed at the connection point (expressed in kWh); and
- a fixed metering charge per revenue meter which is payable each day.

The on-peak, shoulder and off-peak periods applicable to RT17 is defined in Table 5.4.

Table 5.4: Definition of charging windows for RT17

Monday – Friday (excludes public holidays)				Saturday – Sunday (includes public holidays)
Off-peak	**Shoulder**	**On-Peak**	**Off-Peak**	**Off-Peak**
12:00am – 12:00pm	12:00pm – 3:00pm	3:00pm – 9:00pm	9:00pm – 12:00am	All times

5.2.4 Three part time of use demand tariff (RT19)

These are transitional tariffs.

RT19 was available to residential end-users that only import energy from the network and to those that both import and export energy from the network.

RT19 consists of:

- a fixed use of system charge which is payable each day;
- a demand based charge calculated by multiplying the demand charge by the maximum demand in a 30 minute period within the on-peak period defined below at the connection point (expressed in kW) measured over a billing period which is payable each day;
- an on-peak use of system variable charge calculated by multiplying the on-peak energy price by the quantity of on-peak electricity consumed at the connection point (expressed in kWh);
- a shoulder use of system variable charge calculated by multiplying the shoulder energy price by the quantity of shoulder period electricity consumed at the connection point (expressed in kWh);
- an off-peak use of system variable charge calculated by multiplying the off-peak energy price by the quantity of off-peak electricity consumed at the connection point (expressed in kWh); and
- a fixed metering charge per revenue meter which is payable each day.

The on-peak, shoulder and off-peak periods applicable to RT19 are defined in Table 5.5. The same on-peak period applies to both the energy and demand components of this tariff.

Table 5.5: Definition of charging windows for RT19

Monday – Friday (excludes public holidays)				Saturday – Sunday (includes public holidays)
Off-peak	**Shoulder**	**On-Peak**	**Off-Peak**	**Off-Peak**
12:00am – 12:00pm	12:00pm – 3:00pm	3:00pm – 9:00pm	9:00pm – 12:00am	All times

5.2.5 Multi part time of use energy tariff (RT21)

This is a transitional tariff.

RT21 was available to residential end-users that only import energy from the network and to those that both import and export energy from the network.

RT21 consists of:

- a fixed use of system charge which is payable each day;
- an on-peak use of system variable charge calculated by multiplying the on-peak energy price by the quantity of on-peak electricity consumed at the connection point (expressed in kWh);
- a shoulder use of system variable charge calculated by multiplying the shoulder energy price by the quantity of shoulder period electricity consumed at the connection point (expressed in kWh);
- an off-peak use of system variable charge calculated by multiplying the off-peak energy price by the quantity of off-peak electricity consumed at the connection point (expressed in kWh);
- an overnight use of system variable charge calculated by multiplying the overnight energy price by the quantity of overnight electricity consumed at the connection point (expressed in kWh); and
- a fixed metering charge per revenue meter which is payable each day.

The on-peak, shoulder, off-peak and overnight periods applicable to RT21 are defined in Table 5.6.

Table 5.6: Definition of charging windows for RT21

Monday – Friday (excludes public holidays)					Saturday – Sunday (includes public holidays)	
Off-Peak	**Shoulder**	**On-Peak**	**Off-Peak**	**Overnight**	**Off-Peak**	**Overnight**
4:00am – 7:00am	7:00am – 3:00 pm	3:00pm – 9:00pm	9:00pm – 11:00pm	11:00pm – 4:00am	4:00am – 11:00pm	11:00pm – 4:00am

5.2.6 Super off-peak energy tariff (RT35)

This is a new tariff.

It is available to residential end-users that only import energy from the network (exit services) and to those that both import and export energy from the network (bidirectional services).

RT35 consists of:

- a fixed use of system charge which is payable each day;

- an on-peak use of system variable charge calculated by multiplying the on-peak energy price by the quantity of on-peak electricity consumed at the connection point (expressed in kWh);
- a shoulder use of system variable charge calculated by multiplying the shoulder energy price by the quantity of shoulder period electricity consumed at the connection point (expressed in kWh);
- an off-peak use of system variable charge calculated by multiplying the off-peak energy price by the quantity of off-peak electricity consumed at the connection point (expressed in kWh);
- a super off-peak use of system variable charge calculated by multiplying the super off-peak energy price by the quantity of super off-peak electricity consumed at the connection point (expressed in kWh); and
- a fixed metering charge per revenue meter which is payable each day.

The on-peak, shoulder, off-peak and super off-peak periods for RT35 are defined in Table 5.7.

Table 5.7: Definition of charging windows for RT35

Everyday				
Off-Peak	**Shoulder**	**Super off-peak**	**On-Peak**	**Shoulder**
11:00pm – 6:00am	6:00am – 9:00 am	9:00am – 3:00pm	3:00pm – 9:00pm	9:00pm – 11:00pm

5.2.7 Super off-peak demand tariff (RT37)

This is a new tariff.

RT37 is available to residential end-users that only import energy from the network (exit services) and to those that both import and export energy from the network (bidirectional services).

RT37 consists of:

- a fixed use of system charge which is payable each day;
- a demand based charge calculated by multiplying the demand charge by the maximum demand in a 30 minute period within the on-peak period defined below at the connection point (expressed in kW) measured over a billing period which is payable each day;
- an on-peak use of system variable charge calculated by multiplying the on-peak energy price by the quantity of on-peak electricity consumed at the connection point (expressed in kWh);
- a shoulder use of system variable charge calculated by multiplying the shoulder energy price by the quantity of shoulder period electricity consumed at the connection point (expressed in kWh);
- an off-peak use of system variable charge calculated by multiplying the off-peak energy price by the quantity of off-peak electricity consumed at the connection point (expressed in kWh);
- a super off-peak use of system variable charge calculated by multiplying the super off-peak energy price by the quantity of super off-peak electricity consumed at the connection point (expressed in kWh); and
- a fixed metering charge per revenue meter which is payable each day.

The on-peak, shoulder, off-peak and super off-peak periods applicable to the residential multi part time of use energy tariff (RT37) are presented in Table 5.8.

Table 5.8: Definition of charging windows for RT37

Everyday				
Off-Peak	**Shoulder**	**Super off-peak**	**On-Peak**	**Shoulder**
11:00am – 6:00am	6:00am – 9:00 am	9:00am – 3:00pm	3:00pm – 9:00pm	9:00pm – 11:00pm

5.3 Distribution reference services – small and medium business end-users

5.3.1 Anytime energy tariffs (RT2 and RT14)

There are two anytime energy tariffs, one for business end-users that only import energy from the network (RT2) and another for business end-users that both import and export energy from the network (RT14), i.e., that use a bi-directional service. The structure of these two tariffs is the same.

RT2 and RT14 consist of:

- a fixed use of system charge which is payable each day;
- a variable use of system charge calculated by multiplying the energy price by the quantity of electricity consumed at an exit point (expressed in kWh); and
- a fixed metering charge per revenue meter which is payable each day.

5.3.2 Time of use energy tariffs (RT4 and RT16)

These are transitional tariffs.

There are two time of use energy tariffs for business end-users, one for business end-users that only import energy from the network (RT4) and another for business end-users that both import and export energy from the network (RT16). The structure of these two tariffs is the same.

RT4 and RT16 consist of:

- a fixed use of system charge which is payable each day;
- an on-peak use of system variable charge calculated by multiplying the on-peak energy price by the quantity of on-peak electricity consumed at an exit point (expressed in kWh);
- an off-peak use of system variable charge calculated by multiplying the off-peak energy price by the quantity of off-peak electricity consumed at an exit point (expressed in kWh); and
- a fixed metering charge per revenue meter which is payable each day.

The on- and off-peak periods for RT4 and RT16 are defined in Table 5.9.

Table 5.9: Definition of charging windows for RT4 and RT16

Monday – Friday (includes public holidays)			Saturday – Sunday (excludes public holidays)
Off-peak	**On-Peak**	**Off-Peak**	**Off-Peak**
12:00am – 8:00am	8:00am – 10:00pm	10:00pm – 12:00am	All times

5.3.3 Three part time of use energy tariff (RT18)

This is a transitional tariff.

There is a single three part time of use energy tariff for business end-users, available to business end-users that only import energy from the network and to those that both import and export energy from the network. The structure of the tariff is the same for both types of business end-users.

RT18 consists of:

- a fixed use of system charge which is payable each day;
- an on-peak use of system variable charge calculated by multiplying the on-peak energy price by the quantity of on-peak electricity consumed at the connection point (expressed in kWh);
- a shoulder use of system variable charge calculated by multiplying the shoulder energy price by the quantity of shoulder period electricity consumed at the connection point (expressed in kWh);
- an off-peak use of system variable charge calculated by multiplying the off-peak energy price by the quantity of off-peak electricity consumed at the connection point (expressed in kWh); and
- a fixed metering charge per revenue meter which is payable each day.

The on-peak, shoulder and off-peak periods applicable to RT18 are defined in Table 5.10.

Table 5.10: Definition of charging windows for RT18

Monday – Friday (excludes public holidays)				Saturday – Sunday (includes public holidays)
Off-peak	**Shoulder**	**On-Peak**	**Off-Peak**	**Off-Peak**
12:00am – 12:00pm	12:00pm – 3:00pm	3:00pm – 9:00pm	9:00pm – 12:00am	All times

5.3.4 Three part time of use demand tariff (RT20)

This is a transitional tariff.

There is a single three part time of use demand tariff for business end-users, available to business end-users that only import energy from the network and to those that both import and export energy from the network. The structure of the tariff is the same for both types of business end-users.

RT20 consists of:

- a fixed use of system charge which is payable each day;
- a demand based charge calculated by multiplying the demand charge by the maximum demand in a 30 minute period within the on-peak period defined below at the connection point (expressed in kVA) measured over a billing period which is payable each day;
- an on-peak use of system variable charge calculated by multiplying the on-peak energy price by the quantity of on-peak electricity consumed at the connection point (expressed in kWh);
- a shoulder use of system variable charge calculated by multiplying the shoulder energy price by the quantity of shoulder period electricity consumed at the connection point (expressed in kWh);
- an off-peak use of system variable charge calculated by multiplying the off-peak energy price by the quantity of off-peak electricity consumed at the connection point (expressed in kWh); and

- a fixed metering charge per revenue meter which is payable each day.

The on-peak, shoulder and off-peak periods applicable to RT20 are defined in Table 5.11. The same on-peak period applies to both the energy and demand components of this tariff.

Table 5.11: Definition of charging windows for RT20

Monday – Friday (excludes public holidays)				Saturday – Sunday (includes public holidays)
Off-peak	**Shoulder**	**On-Peak**	**Off-Peak**	**Off-Peak**
12:00am – 12:00pm	12:00pm – 3:00pm	3:00pm – 9:00pm	9:00pm – 12:00am	All times

5.3.5 Multi part time of use energy tariff (RT22)

This is a transitional tariff.

There is a single multi part time of use energy tariff for business end-users, available to business end-users that only import energy from the network and to those that both import and export energy from the network. The structure of the tariff is the same for both types of business end-users.

RT22 consists of:

- a fixed use of system charge which is payable each day;
- an on-peak use of system variable charge calculated by multiplying the on-peak energy price by the quantity of on-peak electricity consumed at the connection point (expressed in kWh);
- a shoulder use of system variable charge calculated by multiplying the shoulder energy price by the quantity of shoulder period electricity consumed at the connection point (expressed in kWh);
- an off-peak use of system variable charge calculated by multiplying the off-peak energy price by the quantity of off-peak electricity consumed at the connection point (expressed in kWh);
- a super off-peak use of system variable charge calculated by multiplying the super off-peak energy price by the quantity of super off-peak electricity consumed at the connection point (expressed in kWh);
- an overnight use of system variable charge calculated by multiplying the overnight energy price by the quantity of overnight electricity consumed at the connection point (expressed in kWh); and
- a fixed metering charge per revenue meter which is payable each day.

The on-peak, shoulder, off-peak and overnight periods applicable to RT22 are defined in Table 5.12.

Table 5.12: Definition of charging windows for RT22

Monday – Friday (excludes public holidays)					Saturday – Sunday (includes public holidays)	
Off-Peak	**Shoulder**	**On-Peak**	**Off-Peak**	**Overnight**	**Off-Peak**	**Overnight**
4:00am – 7:00am	7:00am – 3:00 pm	3:00pm – 9:00pm	9:00pm – 11:00pm	11:00pm – 4:00am	4:00am – 11:00pm	11:00pm – 4:00am

5.3.6 Super off-peak energy tariff (RT34 and RT35)

These are new tariffs.

RT34 and 35 consist of:

- A fixed use of system charge which is payable each day.
- An on-peak use of system variable charge calculated by multiplying the on-peak energy price by the quantity of on-peak electricity consumed at the connection point (expressed in kWh).
- A shoulder use of system variable charge calculated by multiplying the shoulder energy price by the quantity of shoulder electricity consumed at the connection point (expressed in kWh).
- An off-peak use of system variable charge calculated by multiplying the off-peak energy price by the quantity of off-peak electricity consumed at the connection point (expressed in kWh).
- A super off-peak use of system variable charge calculated by multiplying the super off-peak energy price by the quantity of super off-peak electricity consumed at the connection point (expressed in kWh).
- A fixed metering charge per revenue meter which is payable each day.

The on-peak, shoulder, off-peak and super off-peak periods are defined in Table 5.13.

Table 5.13: Definition of charging windows for RT34

Everyday				
Off-Peak	**Shoulder**	**Super off-peak**	**On-Peak**	**Shoulder**
11:00pm – 6:00am	6:00am – 9:00 am	9:00am – 3:00pm	3:00pm – 9:00pm	9:00pm – 11:00pm

5.3.7 Super off-peak demand tariff (RT36)

This is a new tariff.

RT36 consists of:

- A fixed use of system charge which is payable each day.
- A demand-based charge calculated by multiplying the demand charge by the maximum demand in a 30-minute period within the on-peak period at the connection point (expressed in kVA) measured over the billing period which is payable each day.
- An on-peak use of system variable charge calculated by multiplying the on-peak energy price by the quantity of on-peak electricity consumed at the connection point (expressed in kWh).
- A shoulder use of system variable charge calculated by multiplying the shoulder energy price by the quantity of shoulder electricity consumed at the connection point (expressed in kWh).
- An off-peak use of system variable charge calculated by multiplying the off-peak energy price by the quantity of off-peak electricity consumed at the connection point (expressed in kWh).
- A super off-peak use of system variable charge calculated by multiplying the super off-peak energy price by the quantity of super off-peak electricity consumed at the connection point (expressed in kWh).

- A fixed metering charge per revenue meter which is payable each day.

The on-peak, shoulder, off-peak and super off-peak periods applicable to RT36 and RT37 are defined in Table 5.14.

Table 5.14: Definition of charging windows for RT36

Everyday				
Off-Peak	**Shoulder**	**Super off-peak**	**On-Peak**	**Shoulder**
11:00pm – 6:00am	6:00am – 9:00 am	9:00am – 3:00pm	3:00pm – 9:00pm	9:00pm – 11:00pm

5.3.8 Super off-peak demand tariff (RT37)

This is a new tariff.

RT37 consists of:

- A fixed use of system charge which is payable each day.
- A demand-based charge calculated by multiplying the demand charge by the maximum demand in a 30-minute period within the on-peak period at the connection point (expressed in kW) measured over the billing period which is payable each day.
- An on-peak use of system variable charge calculated by multiplying the on-peak energy price by the quantity of on-peak electricity consumed at the connection point (expressed in kWh).
- A shoulder use of system variable charge calculated by multiplying the shoulder energy price by the quantity of shoulder electricity consumed at the connection point (expressed in kWh).
- An off-peak use of system variable charge calculated by multiplying the off-peak energy price by the quantity of off-peak electricity consumed at the connection point (expressed in kWh).
- A super off-peak use of system variable charge calculated by multiplying the super off-peak energy price by the quantity of super off-peak electricity consumed at the connection point (expressed in kWh).
- A fixed metering charge per revenue meter which is payable each day.

The on-peak, shoulder, off-peak and super off-peak periods applicable to RT36 and RT37 are defined in Table 5.15.

Table 5.15: Definition of charging windows for RT37

Everyday				
Off-Peak	**Shoulder**	**Super off-peak**	**On-Peak**	**Shoulder**
11:00pm – 6:00am	6:00am – 9:00 am	9:00am – 3:00pm	3:00pm – 9:00pm	9:00pm – 11:00pm

5.4 Distribution reference services – large business end-users

5.4.1 High voltage metered demand tariff (RT5)

RT5 consists of:

a. a fixed metered demand charge which is payable each day based on the rolling 12-month maximum half-hourly demand at a connection point (expressed in kVA) multiplied by (1-Discount);

b. a variable metered demand charge calculated by multiplying the demand price (in excess of the lower threshold) by the rolling 12-month maximum half-hourly demand at a connection point (expressed in kVA) minus the lower threshold with the result multiplied by (1-Discount);

c. if the metered demand is greater than 1,000 kVA a variable demand length charge calculated by multiplying the demand length price by the electrical distance to the zone substation by the rolling 12-month maximum half-hourly demand (expressed in kVA) minus 1,000 kVA (Note: a different rate applies after 10 km); and

d. a fixed metering charge per revenue meter which is payable each day.

Notes:

1. If a user reduces its rolling 12-month maximum half-hourly demand at a connection point as set out in the process in section 5.3.3 below, then for the purposes of calculating parts a, b and c of the RT5 tariff the 'rolling 12-month maximum half-hourly demand' shall be the reduced amount from the date approved by Western Power.

The on and off-peak periods for this tariff are defined in the following table (all times are WST):

Table 16: On and off-peak for RT5

Monday – Friday (excludes public holidays)			Saturday – Sunday (includes public holidays)
Off-peak	**On-Peak**	**Off-Peak**	**Off-Peak**
12:00am – 3:00pm	3:00pm – 9:00pm	9:00pm – 12:00am	All times

A discount, based on the percentage of off-peak energy consumption (as a proportion of the total energy consumption), applies to this tariff.

The Discount is defined as:

For MD < 1,000 kVA	$(E_{Off\text{-}peak}/E_{Total}) * DF$
For 1,000 <= MD <1,500 kVA	$((1500 - MD)/500) * (E_{Off\text{-}peak}/E_{Total}) * DF$
For MD => 1,500 kVA	0

Where:

MD is the rolling 12-month maximum half-hourly demand at a connection point (expressed in kVA);

DF is the discount factor, which is set at 30%;

$E_{Off\text{-}peak}$ is the total off-peak energy for the billing period (expressed in kWh); and

E_{Total} is the total energy (both on and off-peak) for the billing period (expressed in kWh).

Notes:

This discount does not apply to the demand-length portion of the charge.

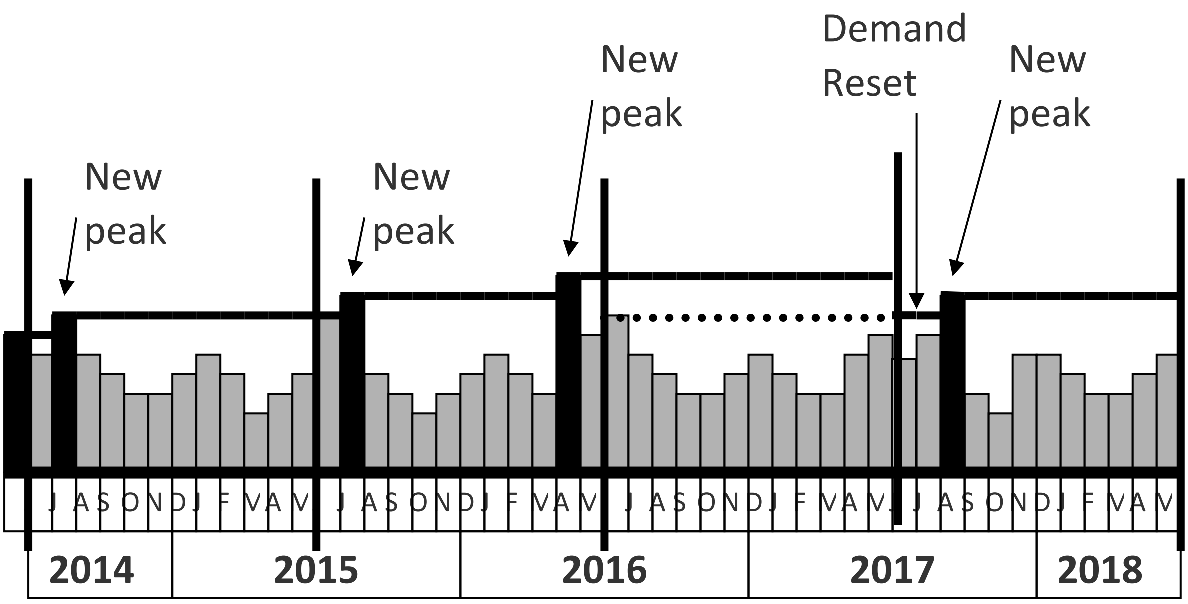
Derivation of rolling 12-month peak

The metered demand tariff is based on a metered annual any time maximum demand with a discount to give credit for off-peak energy usage as a proportion of total energy used.

The annual any time maximum demand is the rolling peak value over the previous 12 months. This rolling peak, rather than a monthly-metered peak, is chosen for compatibility with the CMD tariffs that are based on a contracted maximum demand set for a defined period. A tariff based on a metered monthly peak would need to be higher to recover the same revenue from these users due to the effect of seasonal variation in loads.

The principle of using this rolling peak is illustrated in Figure 7.1.

Figure 4: Rolling Peak Illustration



There is no excess network usage charge for this tariff. The incentive to control the peak demand is significant because any half-hourly excess peak would be retained in the charges for a full 12 months. However, this is not intended to be unreasonably punitive to users and the negative impact of an extraordinary event would be assessed on a case-by-case basis.

If a user, or its customer, has implemented initiatives to reduce the future maximum demand on a permanent basis including:

- the implementation of load control, energy efficiency equipment or solutions at the connection point; or
- a fundamental change in the nature of the business or operation conducted at the connection point; or

- a shutdown of the business or operation conducted at the connection point; or
- some other special circumstance or arrangement that reduces the maximum demand at the connection point

then the user may apply to Western Power for the rolling 12-month period and maximum metered demand to be reset.

The application must include a forecast of maximum demand over the future 12-month period, details of why the user expects the demand will be lower, evidence to support the change and the date the user wishes the revised maximum metered demand to apply from. If Western Power considers, as a reasonable and prudent person and in accordance with good electricity industry practice, that the revised maximum metered demand is reasonable, Western Power must reset the rolling 12-month period and maximum demand in line with the application.

If the actual maximum metered demand exceeds the reset maximum metered demand within 12 months of the reset, an adjustment will be made to charges as though the actual maximum metered demand had applied from the date the reset was implemented.

The off-peak discount is applied monthly, based on the metered off-peak and total energy amounts. The discount is intended to create an incentive for users to use the network off-peak and is provided as a specific reduction in the monthly charge depending on the proportion of off-peak energy used.

The tariff also includes a 'demand-length' component for demands greater than 1,000 kVA, identical to that applying in the CMD tariffs, based on the rolling annual peak.

The demand price is in rate block format. The transition points are set at 300 kVA and 1,000 kVA and the discount phases out at 1,500 kVA. At 1,500 kVA the tariff is set to be less attractive than the CMD tariffs for most users.

A discount mechanism applies to this tariff as defined above.

5.4.2 Low voltage metered demand tariff (RT6)

RT6 consists of:

a. a fixed metered demand charge which is payable each day based on the rolling 12-month maximum half-hourly demand at a connection point (expressed in kVA) multiplied by (1-Discount);

b. a variable metered demand charge calculated by multiplying the demand price (in excess of lower threshold) by the rolling 12-month maximum half-hourly demand at a connection point (expressed in kVA) minus the lower threshold with the result multiplied by (1-Discount);

c. if the metered demand is greater than 1,000 kVA a variable demand length charge calculated by multiplying the demand length price by the electrical distance to the zone substation by the rolling 12-month maximum half-hourly demand (expressed in kVA) minus 1,000 kVA (Note: a different rate applies after 10 km); and

d. a fixed metering charge per revenue meter which is payable each day.

Notes:

This tariff is similar to RT5 in section 5.4.1 but for customers connected at low voltage. The higher tariff rates reflect the additional cost of using the low voltage network.

The on and off-peak periods for this tariff are defined in the following table (all times are WST):

Table 17: On and off-peak for RT6

Monday – Friday (excludes public holidays)			Saturday – Sunday (includes public holidays)
Off-peak	**On-Peak**	**Off-Peak**	**Off-Peak**
12:00am – 3:00pm	3:00pm – 9:00pm	9:00pm – 12:00am	All times

If a user reduces its rolling 12-month maximum half-hourly demand at a connection point as set out in the process in section 5.4.3 below, then for the purposes of calculating parts a, b and c of the RT6 tariff the 'rolling 12-month maximum half-hourly demand' shall be the reduced amount from the date approved by Western Power.

Discount

The same formula detailed for RT5 also applies for RT6.

Derivation of 12-month rolling peak

The same processes detailed for RT5 also applies for RT6.

5.4.3 High voltage contract maximum demand tariff (RT7)

RT7 consists of:

a. If the contracted maximum demand (CMD) is less than 7,000 kVA:
   i. a fixed demand charge for the first 1,000 kVA which is payable each day; plus
   ii. a variable demand charge calculated by multiplying the applicable demand price by the CMD (expressed in kVA) minus 1,000 kVA; plus
   iii. a variable demand length charge calculated by multiplying the demand length price by the electrical distance to the zone substation by the CMD (expressed in kVA) minus 1,000 kVA (Note: a different rate applies after 10 km);
b. If the CMD is equal to or greater than 7,000 kVA:
   i. a variable demand charge calculated by multiplying the applicable demand price by the CMD (expressed in kVA); plus
   ii. a variable demand length charge calculated by multiplying the demand length price by the electrical distance to the zone substation by the CMD (expressed in kVA) (Note: a different rate applies after 10 km);
c. a fixed metering charge per revenue meter which is payable each day;
d. a fixed administration charge which is payable each day; and
e. excess network usage charges (if applicable).

Notes:

For connection points located at the zone substation the fixed and variable demand charge specified in sections (a)(i), (a)(ii) & (b)(i) is to be calculated using the transmission component only. In all other instances, the fixed and variable demand charge specified in sections (a)(i), (a)(ii) & (b)(i) is to be calculated using the bundled charge.

If this tariff applies in relation to a connection point the subject of a capacity allocation arrangement pursuant to reference services D2 as set out in Appendix E of the Access Arrangement, then the charge to each user at this connection point for the duration of the capacity allocation arrangement is the sum of all tariff components a to d, multiplied by the percentage of the contracted capacity allocated to the user pursuant to the capacity allocation arrangement as compared to the total contracted capacity at the connection point.

Excess network usage charges

An additional charge applies to this tariff where the peak half-hourly demand exceeds the nominated CMD during the billing period of the load.

The excess network usage charge (ENUC) is calculated by applying a factor to the excess usage as follows:

$$ENUC = ENUC_{Transmission} + ENUC_{Distribution}$$

Where:

$ENUC_{Transmission}$	$= ENUM * (PD - CMD) * DC_{Transmission} / CMD;$
$ENUC_{Distribution}$	$= ENUM * (PD - CMD) * (DC_{Distribution} + DLC) / CMD;$
ENUM	is the Excess network usage multiplier factor;
PD	is the peak half-hourly demand during the billing period of the load (expressed in kVA);
CMD	is the nominated CMD for the billing period of the load (expressed in kVA);
$DC_{Transmission}$	are the applicable transmission components of the fixed and variable demand charges for the billing period for the nominated CMD;
$DC_{Distribution}$	are the applicable distribution components of the fixed and variable demand charges for the billing period for the nominated CMD; and
DLC	are the applicable variable demand length charges for the billing period for the nominated CMD.

Notes:

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

5.4.4 Low voltage contract maximum demand tariff (RT8)

RT8 consists of:

a. If the contracted maximum demand (CMD) is less than 7,000 kVA:
    i. a fixed demand charge for the first 1,000 kVA which is payable each day; plus
    ii. a variable demand charge calculated by multiplying the applicable demand price by the CMD (expressed in kVA) minus 1,000 kVA; plus

iii. a variable demand length charge calculated by multiplying the demand length price by the electrical distance to the zone substation by the CMD (expressed in kVA) minus 1,000 kVA (Note: a different rate applies after 10 km);

b. If the CMD is equal to or greater than 7,000 kVA:

i. a variable demand charge calculated by multiplying the applicable demand price by the CMD (expressed in kVA); plus

ii. a variable demand length charge calculated by multiplying the demand length price by the electrical distance to the zone substation by the CMD (expressed in kVA) (Note: a different rate applies after 10 km);

c. a fixed low voltage charge which is payable each day;

d. a variable low voltage charge calculated by multiplying the low voltage demand price by the CMD (expressed in kVA);

e. a fixed metering charge per revenue meter which is payable each day;

f. a fixed administration charge which is payable each day; and

g. excess network usage charges (if applicable).

Notes:

This tariff is identical to RT7 in section 5.4.3, with an additional low voltage charge to cover the use of transformers and LV circuits.

If this tariff applies in relation to a connection point the subject of a capacity allocation arrangement pursuant to reference services D2 as set out in Appendix E of the Access Arrangement, then the charge to each user at this connection point for the duration of the capacity allocation arrangement is the sum of all tariff components a to d, multiplied by the percentage of the contracted capacity allocated to the user pursuant to the capacity allocation arrangement as compared to the total contracted capacity at the connection point.

Excess network usage charges

An additional charge applies to this tariff where the peak half-hourly demand exceeds the nominated CMD during the billing period of the load. The excess network usage charge (ENUC) is calculated by applying a factor to the excess usage as follows:

$$ENUC = ENUC_{Transmission} + ENUC_{Distribution}$$

Where

$ENUC_{Transmission}$	$= ENUM * (PD – CMD) * DC_{Transmission} / CMD$;
$ENUC_{Distribution}$	$= ENUM * (PD – CMD) * (DC_{Distribution} + DLC + LVC) / CMD$;
ENUM	is the Excess network usage multiplier factor;
PD	is the peak half-hourly demand during the billing period of the load (expressed in kVA);
CMD	is the nominated CMD for the billing period of the load (expressed in kVA);
$DC_{Transmission}$	are the applicable transmission components of the fixed and variable demand charges for the billing period for the nominated CMD;

$DC_{Distribution}$	are the applicable distribution components of the fixed and variable demand charges for the billing period for the nominated CMD;
DLC	are the applicable variable demand length charges for the billing period for the nominated CMD; and
LVC	are the applicable additional fixed and additional demand (low voltage) charges for the billing period for the nominated CMD.

Notes:

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

5.5 Distribution reference services – other

5.5.1 Streetlight tariff (RT9)

The streetlight tariff includes a single variable charge that does not change throughout the day, alongside other fixed charges.

RT9 consists of:

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

5.5.2 Unmetered supplies tariff (RT10)

There is a reference tariff for unmetered supply points. While this tariff is similar in design to the streetlight tariff, it is intended to be distinct to this tariff. That is, any unmetered supply point who connects with facilities and equipment deemed to be associated with streetlights will be placed on the streetlight tariff rather than this tariff.

RT10 consists of:

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

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

- the fixed use of system charge for RT9 which is payable each day; and
- the variable use of system charge for RT9 calculated by multiplying the energy price by the estimated quantity of electricity consumed at an exit point (expressed in kWh and based on the nameplate rating of the connected equipment and the hours of operation).

5.5.3 Distribution generator tariff (RT11)

The structure of the distribution generator tariff is similar to the transmission generator tariff (TRT2), in that it consists of multiple location specific, cost-reflective prices. This tariff is individually calculated for each distribution connected generator and so can differ in structure between end-users.

RT11 consists of:

- A variable connection charge calculated by multiplying the connection price by the loss-factor adjusted declared sent-out capacity (DSOC) at the entry point (expressed in kW);
- A variable control system service charge calculated by multiplying the control system service price by the nameplate output of the generator at the entry point (expressed in kW);
- A variable use of system charge calculated by multiplying the use of system price (based on the location of the electrically closest major generator) by the loss-factor adjusted DSOC at the entry point (expressed in kW);
- If the DSOC is less than 7,000 kVA:
  - if the entry point is connected at 415 V or less and the DSOC is equal to or greater than 1,000 kVA a variable demand length charge calculated by multiplying the applicable demand length price by the electrical distance between the relevant HV network connection point and the electrically closest zone substation by the DSOC (expressed in kVA) minus 1,000 kVA (Note: a different rate applies after 10 km); or
  - if the entry point is connected at greater than 415 V and the DSOC is equal to or greater than 1,000 kVA a variable demand length charge calculated by multiplying the applicable demand length price by the electrical distance between the entry point and the electrically closest zone substation by the DSOC (expressed in kVA) minus 1,000 kVA (Note: a different rate applies after 10 km);
- If the DSOC is equal to or greater than 7,000 kVA:
  - if the entry point is connected at 415 V or less a variable demand length charge calculated by multiplying the applicable demand length price by the electrical distance between the relevant HV network connection point and the electrically closest zone substation by the DSOC (expressed in kVA) (Note: a different rate applies after 10 km); or
  - if the entry point is connected at greater than 415 V a variable demand length charge calculated by multiplying the applicable demand length price by the electrical distance between the entry point and the electrically closest zone substation by the DSOC (expressed in kVA) (Note: a different rate applies after 10 km);
- A fixed metering charge per revenue meter which is payable each day; and
- Excess network usage charges calculated as set out below.

The loss factor used to calculate the loss-factor adjusted DSOC is the relevant portion from the generator to the zone substation of the loss factor published by the AEMO for that generator.

For this reference tariff a unity power factor is assumed when converting between kW and kVA.

An excess network usage charge (ENUC) applies to this tariff where the peak half-hourly demand exceeds the nominated DSOC during the billing period except where Western Power deems the export of power in excess of DSOC was required for power system reliability and security purposes.

The ENUC is calculated by applying a factor to the excess usage as follows:

$ENUC = ENUC_{Transmission} + ENUC_{Distribution}$

Where

$ENUC_{Transmission} = ENUM * (PD_{kW} – DSOC_{kW}) * TEPC / DSOC_{kW}$;

$ENUC_{Distribution} = ENUM * (PD_{kVA} – DSOC_{kVA}) * (DLC) / DSOC_{kVA}$;

ENUM	is the Excess network usage multiplier factor;
PD	is the peak half-hourly demand during the billing period (expressed in kVA and kW);
DSOC	is the nominated DSOC for the billing period (expressed in kVA and kW);
TEPC	is the sum of the variable connection charge, variable control system service charge and variable use of system charge for the billing period for the nominated DSOC; and
DLC	is the applicable variable demand length charge for the billing period for the nominated DSOC.

Notes:

The ENUC does not include the metering components of the tariff.

5.5.4 Services facilitating a distribution generation or other non-network solution (RT23 and RT24)

These services and tariffs are for situations where the connection of distributed generating plant or other equipment is connected that gives rise to a reduction in forecast costs for Western Power.

RT23 consists of:

- the reference tariff (RT11) applicable to the entry reference service B1 upon which the B3 – Entry Service Facilitating a Distributed Generation or Other Non-Network Solution is provided; less
- the discount that applies to the connection point as set out below.

Western Power will provide a discount to RT11 in circumstances where the service allows for facilities and equipment connected behind the connection point (including distributed generating plant and other non-network solutions) that results in Western Power's capital-related costs or non-capital costs reducing as a result of the entry point for the distributed generating plant or other non-network solution being located in that particular part of the covered network.

In situations where a user connects facilities and equipment (including distributed generating plant) to the Western Power Network and has applied and been assessed as resulting in Western Power's capital-related costs or non-capital costs reducing as a result of the entry point for the distributed generating plant or other non-network solution being located in that particular part of the covered network, the discount to be applied is an annualised discount amount (which can be no greater than the annual charge), calculated as the present value of FCp less FCn over a period of Y years using discount rate W.

Where:

FCp	is the present value of the Western Power committed forecast capital-related costs and non-capital costs that would be incurred over Y years if the facilities and equipment

(including distributed generating plant) were not to connect to the Western Power Network.

FCn is the present value of Western Power's forecast capital-related costs and non-capital costs over Y years that are anticipated to be incurred if the facilities and equipment (including distributed generating plant) were to connect to the Western Power Network.

Y is the period over which the present value assessment is to occur which is 15 years unless otherwise agreed between Western Power and the user.

W is the Weighted Average Cost of Capital as set out in section 5.4 of the Access Arrangement that applies in the pricing year.

5.5.5 Distribution storage service tariffs (RT38 and RT39)

RT38 and RT39 consist of:

- A fixed use of system charge that reflects the costs of providing connection assets which is payable each day.
- For net consumption from the Western Power network:
  - An on-peak use of system variable charge calculated by multiplying the on-peak energy price by the quantity of on-peak electricity consumed at the connection point (expressed in kWh).
  - A shoulder use of system variable charge calculated by multiplying the shoulder energy price by the quantity of shoulder electricity consumed at the connection point (expressed in kWh).
  - An off-peak use of system variable charge calculated by multiplying the off-peak energy price by the quantity of off-peak electricity consumed at the connection point (expressed in kWh).
  - A super off-peak use of system variable charge calculated by multiplying the super off-peak energy price by the quantity of super off-peak electricity consumed at the connection point (expressed in kWh).
- For net exports to the Western Power network:
  - An on-peak use of system variable charge calculated by multiplying the on-peak energy price by the quantity of on-peak electricity exported at the connection point (expressed in kWh).
  - An shoulder use of system variable charge calculated by multiplying the shoulder energy price by the quantity of shoulder electricity exported at the connection point (expressed in kWh).
  - An off-peak use of system variable charge calculated by multiplying the off-peak energy price by the quantity of off-peak electricity exported at the connection point (expressed in kWh).
  - A stepped super off-peak use of system variable charge calculated by multiplying:
    - The first 3kWh of super off-peak electricity exported (expressed in kWh) at the connection point by the super off-peak energy price measured over a billing period which is payable each day.
    - The quantity of super off-peak electricity in excess of 3kWh exported (expressed in kWh) at the connection point by the super off-peak energy price measured over a billing period which is payable each day.
- A fixed metering charge per revenue meter which is payable each day.

The on-peak, shoulder, off-peak and super off-peak periods applicable to the distribution storage service tariffs are presented in Table 5.18.

Table 5.18: Definition of charging windows for RT38 and RT39

Everyday				
Off-Peak	**Shoulder**	**Super off-peak**	**On-Peak**	**Shoulder**
11:00pm – 6:00am	6:00am – 9:00 am	9:00am – 3:00pm	3:00pm – 9:00pm	9:00pm – 11:00pm

5.5.6 Electric vehicle charging service tariffs (RT40 and RT41)

RT40 and RT41 consist of:

- A fixed use of system charge that reflects the costs of providing connection assets which is payable each day.
- An on-peak use of system variable charge that varies with network utilisation defined below which is calculated by multiplying the on-peak energy price relevant to the network utilisation percentage band detailed below by the quantity of on-peak electricity consumed at the connection point (expressed in kWh).
- A shoulder use of system variable charge that varies with network utilisation defined below which is calculated by multiplying the shoulder energy price relevant to the network utilisation percentage band detailed below by the quantity of shoulder electricity consumed at the connection point (expressed in kWh).
- An off-peak use of system variable charge that varies with network utilisation defined below which is calculated by multiplying the off-peak energy price relevant to the network utilisation percentage band detailed below by the quantity of off-peak electricity consumed at the connection point (expressed in kWh).
- A super off-peak use of system variable charge that varies with network utilisation defined below which is calculated by multiplying the super off-peak energy price relevant to the network utilisation percentage band detailed below by the quantity of super off-peak electricity consumed at the connection point (expressed in kWh).
- A demand-based charge that varies with network utilisation defined below calculated by multiplying the demand charge relevant to the network utilisation percentage band detailed below by the maximum demand in a 30 minute period within the on-peak period defined below at the connection point (expressed in kVA) measured over a billing period which is payable each day.
- A fixed metering charge per revenue meter which is payable each day.

The on-peak, shoulder, off-peak and super off-peak periods applicable to the electric vehicle charging service tariffs are presented in Table 5.19.

Table 5.19: Definition of charging windows for RT40 and RT41

Everyday				
Off-Peak	**Shoulder**	**Super off-peak**	**On-Peak**	**Shoulder**
11:00pm – 6:00am	6:00am – 9:00 am	9:00am – 3:00pm	3:00pm – 9:00pm	9:00pm – 11:00pm

The calculation of network utilisation:

- is based on demand in the twelve 30-minute intervals between 3pm and 9pm (being the on-peak period); and
- excludes any 30-minute interval where demand is less than 10kW.

The formula for calculation of the network utilisation for this tariff is:

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

The resultant percentage from the above calculation is used to assign the site to the relevant network utilisation band as set out below that will determine the network charges applicable to the site.

Table 5.20: Network utilisation percentage bands

1	0% - < or = to 15%
2	>15% - < or = to 30%
3	Greater than 30%

5.5.7 Other charging components (RT25 to RT33)

The following tariffs are provided on a fee for service basis and the revenue does not contribute towards the recovery of Western Power's revenue target as approved by the ERA, i.e.:

- RT25 consists of a charge per connection point supply abolishment;
- RT26 consists of a charge per request to remotely control a load or inverter;
- RT28 consists of a charge per request for remote de-energisation;
- RT29 consists of a charge per request for remote re-energisation;
- RT30 consists of a user-specific charge that is to be an amount which reflects the costs to Western Power of replacing the existing streetlight with the LED streetlight replacement requested by the user which may consist of capital and non-capital costs;
- RT31 consists of a charge per request for a site visit to support remote re-energisation of a customer;
- RT32 consists of a charge per request for a site visit to support manual de-energisation of a customer; and
- RT33 consists of a charge per request for a site visit to support manual re-energisation of a customer.

Prices for supply abolishment (RT25), remote load / inverter control (RT26), remote de-energise (RT28) and remote re-energise (RT29) services are calculated using a bottom-up building block methodology, to recover expected input costs such as administration, field labour, materials, and fleet costs, as relevant to each service, seeking to achieve the lowest sustainable costs of providing the relevant service.

6. Price setting for transmission reference services

This section explains the price setting process for end-users connected to the transmission network. Specifically, the methodology to set prices for:

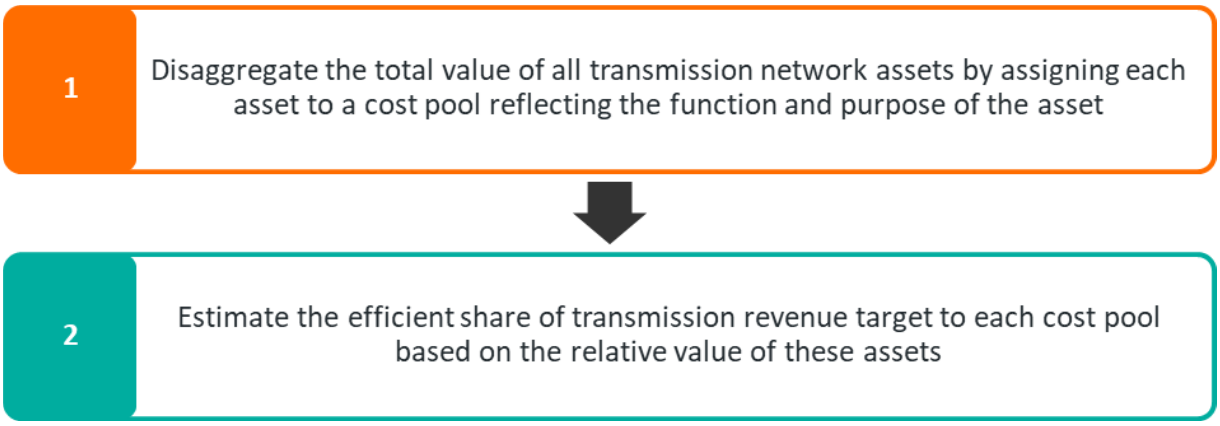
- existing transmission connected end-users, including the estimation of total efficient costs for each transmission reference service and the bill impact considerations for the recovery of these efficient costs; and
- new nodes on the transmission network.

6.1 Calculation of total efficient costs for transmission reference services

Similarly, to the distribution efficient cost estimation methodology, the efficient disaggregation of transmission network costs is based on the relative value of assets and the relative use of these assets by end-users using each transmission reference service. This is achieved through the use of location specific and end-user specific prices for some components of transmission reference tariffs.

The estimation of the efficient contribution of transmission reference services to total transmission costs follows the high-level process detailed in Figure 6.1.

Figure 6.1: Transmission services efficient cost estimation flow chart



The remainder of this section provides a detailed description and explanation of the steps presented in Figure 6.1 (including what the asset pools are).

6.1.1 Step 1 - definition of transmission service cost pools

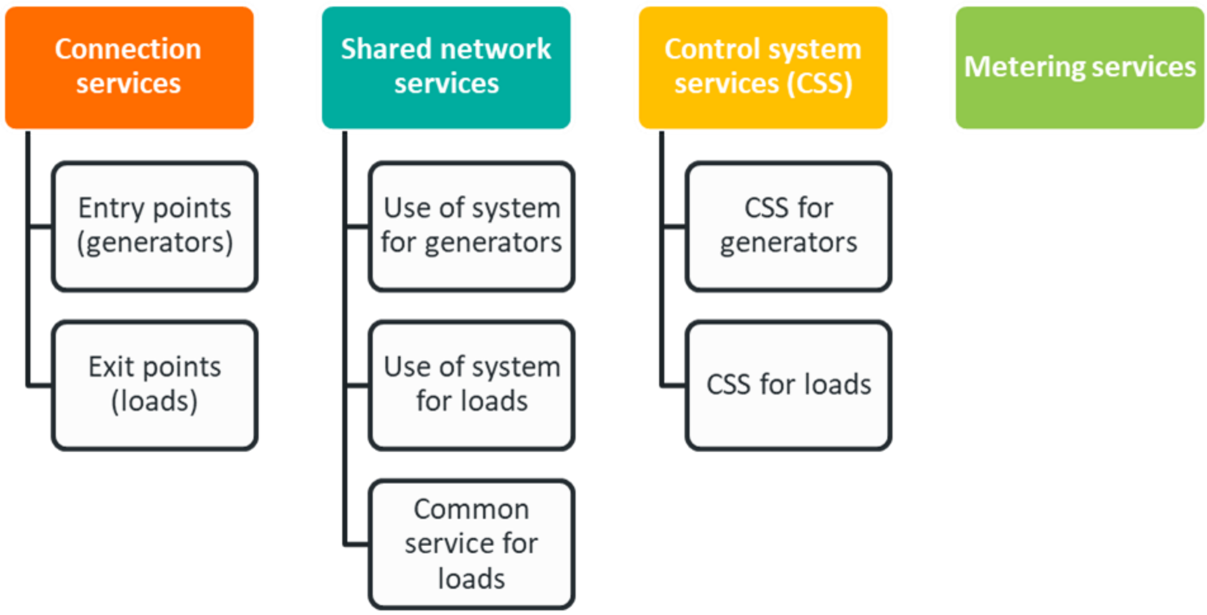
The transmission cost pools reflect the different functions performed by groups of assets in the transmission network. The functions of these assets include:

- providing connection services for end-users – assigned to the connection services cost pool;
- voltage control services – assigned to both the connection services and shared network services cost pools as voltage control is partly location specific, allocated to connection services, and partly whole of system related, allocated to shared network services;
- supporting the general functionality of the transmission network, such as transmission substations and poles and lines that are not directly attributable to the connection of a particular end-user – assigned to the shared network services cost pool;
- providing control services across the transmission network, such as SCADA assets and SCADA control systems – assigned to the control system services (CSS) cost pool; and

- metering for transmission connected end-users – assigned to the metering services cost pool.

The transmission service cost pools are presented in Figure 6.2.

Figure 6.2: Transmission service cost pools



The value of transmission network assets is estimated using a similar process to distribution network assets. That is, through the development of a transmission network asset register for the following relevant transmission network assets:

- connection assets at the entry point to the transmission network, for generators, and exit point, for loads;
- shared network assets, i.e., transmission substations, poles, and lines; and
- voltage control assets, i.e., capacitor and reactor banks.

This asset register, which also contains information regarding the geographic location of the asset, is supplemented by information regarding the cost of service for metering and CSS assets. The costs for the provision of metering and CSS assets and services are determined using the building block approach, similar to that used in establishing target revenue for distribution and transmission services.

In addition, the assignment of transmission network assets and transmission cost of service to cost pools is further segmented by an assignment between the two distinct transmission end-user types, generators, and loads. Table 6.1 presents the nature by which the cost pools are further segmented to generators and loads.

Table 6.1: Assignment of transmission cost pools between loads and generators

Transmission cost pools	Loads (exit points)	Generators (entry points)
Connection services	• Specific exit connection assets • 33 per cent of the value of voltage control assets at exit connection points	• Specific entry connection assets • 33 per cent of the value of voltage control assets at entry connection points

Transmission cost pools	Loads (exit points)	Generators (entry points)
Use of system (shared network services)	• 50 per cent of the total value of shared network service assets	• 20 per cent of the total value of shared network service assets
Common service (shared network services)	• 30 per cent of the total value of shared network service assets • 67 per cent of the value of voltage control assets at both exit and entry connection points	• *None*
CSS	• Total CSS costs proportioned based on the total number of load control points	• Total CSS costs proportioned based on the total number of generator control points
Metering	• Total metering costs proportioned based on the number of transmission network connected loads	• Total metering costs proportioned based on the number of transmission network connected generators

6.1.2 Step 2 – estimate the share of transmission target revenue from each transmission cost pool

The result of step 1 is a disaggregation of the combined value of all assets in the transmission network to each cost pool. In step 2, this cost pool disaggregation is used to estimate the efficient share of total transmission target revenue that is attributable to these same cost pools. This determines the efficient level of revenue to be recovered from each component of transmission reference tariffs.

In order to estimate the contribution towards total efficient costs for transmission reference services across cost pools, the following information is required:

- the total value of assets associated with each transmission cost pool, denoted as $\mathrm{V}_{\mathrm{Cost\ Pool}}$, which is obtained in step 1 using the replacement value of assets, supplemented with the cost of supply estimated by a building block approach where required; and
- the transmission target revenue less the components directly attributable to CSS and metering services, denoted as Rev.

Table 6.2 presents the process to estimate the efficient contribution to total transmission target revenue from each cost pool. A key component to this process is the revenue rate of return, RR, which is the ratio of transmission target revenue to the sum of asset values for all cost pools excluding CSS and metering (which have a cost of service estimated from the revenue model). The sum of the efficient revenue of each cost pool will be equal to the transmission target revenue each year.

Table 6.2: Calculation of transmission cost allocation

Transmission cost pool	Cost pool asset value	Efficient revenue
Connection (exit)	$\mathrm{V}_{\mathrm{Exit\ connection}}$	$\mathrm{V}_{\mathrm{Exit\ connection}} \times \mathrm{RR}$
Connection (entry)	$\mathrm{V}_{\mathrm{Entry\ connection}}$	$\mathrm{V}_{\mathrm{Entry\ connection}} \times \mathrm{RR}$
Use of system (exit)	$\mathrm{V}_{\mathrm{Exit\ UOS}}$	$\mathrm{V}_{\mathrm{Exit\ UOS}} \times \mathrm{RR}$
Use of system (entry)	$\mathrm{V}_{\mathrm{Entry\ UOS}}$	$\mathrm{V}_{\mathrm{Entry\ UOS}} \times \mathrm{RR}$
Common service	V_{CS}	$\mathrm{V}_{\mathrm{CS}} \times \mathrm{RR}$
CSS (exit)	$\mathrm{V}_{\mathrm{Exit\ CSS}}$	$\mathrm{V}_{\mathrm{Exit\ CSS}}$

Transmission cost pool	Cost pool asset value	Efficient revenue
CSS (entry)	$V_{\text{Entry CSS}}$	$V_{\text{Entry CSS}}$
Metering	V_{Metering}	V_{Metering}
Total asset valuation excluding CSS and metering	$V_{\text{All}} = \sum V_{\text{Cost Pools}} - V_{\text{Exit CSS}} - V_{\text{Entry CSS}} - V_{\text{Metering}}$	
Revenue rate of return	$RR = \frac{\text{Rev} - V_{\text{Exit CSS}} - V_{\text{Entry CSS}} - V_{\text{Metering}}}{V_{\text{All}}}$	

Table 6.3 presents the efficient contribution of total transmission revenue from each of the cost pools, which underpins the share of total transmission costs assigned to each cost pool each year.

Table 6.3: Efficient share of transmission service revenue to cost pools over the AA5 period

Transmission cost pool	Efficient share of total transmission reference service revenue
Connection (exit)	*26.5%*
Connection (entry)	*2.3%*
Use of system (exit)	*28.3%*
Use of system (entry)	*11.3%*
Common service	*21.1%*
CSS (exit)	*8.8%*
CSS (entry)	*1.6%*
Metering	*0.1%*

6.1.3 Implementation considerations for efficient transmission service cost estimation

Given the small number of transmission connections relative to distribution end-users, moderate changes in target revenue or other inputs to the efficient cost estimation methodology may lead to larger effects for individual transmission connections relative to distribution end-users. Further, the location specific aspect of the transmission price methodology can introduce volatility to individual prices as some changes in network utilisation are beyond the control of an individual transmission connection.

For these reasons, Western Power implements a form of price moderation within the transmission pricing model that can introduce a variance between the efficient cost estimation and the recovered revenue across the transmission cost pools. This variance may require a redistribution among the cost pools.

There are a number of prices that form part of the transmission reference tariffs, some of which are prone to the volatility explained above. The price components for transmission reference tariffs are:

- connection prices;
- CSS prices;
- metering prices;
- use of system prices; and
- common service prices.

Connection prices reflect the price for the utilisation of Western Power owned connection assets. These connection charges are individually calculated to reflect the actual connection assets that apply to that user. The connection price is based on achieving a regulated return on all relevant assets and an allocation of the transmission network operating costs.

CSS prices reflect the cost pool allocation for these services, which is derived using the building block approach in the revenue model. Western Power explicitly moderates changes in CSS prices to control for significant price changes between years for Western Power's transmission connections.

Similar to connection prices, Western Power sets metering prices for end-users connected to the transmission network each year to recover the costs of providing metering services to these end-users, ie, a mix of fixed asset costs and variable maintenance costs. The fixed costs reflect the historical value of these metering assets while the maintenance and operating costs are derived using the building block approach in the revenue model. In order to moderate prices for transmission reference services, Western Power may deviate from the complete recovery of the metering cost pool from metering prices.

The use of system charges for the transmission network are obtained using a cost reflective network pricing methodology which, as described above, can introduce volatility in the resulting location specific prices. It is therefore appropriate to moderate any price fluctuations to mitigate price shock and improve certainty to end-users. Western Power therefore includes variations to the transmission use of system prices in order to moderate the annual changes in this price.

In order to handle the impact on recovered transmission revenue from the price moderation of transmission metering and use of system prices, the common services cost pool can be adjusted to balance any variation between recovered revenue and cost allocation in the other transmission cost pools. However, the common service price itself is also subject to a price moderation. Similar to the transmission use of system prices, Western Power moderates the annual change in common service prices to ensure control over the stability of total prices for transmission connections.

However, with no balancing mechanism for the moderation of common service prices there is a possibility that transmission revenue may be under-recovered. In order to balance the total transmission revenue recovery each year, any under-recovery of transmission revenue is added to the pass through of transmission costs to distribution end-users.

As part of the transmission pricing methodology, the pass through to distribution end-users is allocated to each zone substation across the distribution network using a location specific use of network methodology. To allocate the under-recovery to this pass through, the revenue allocated to each zone substation is scaled by a uniform proportion so that the revised transmission revenue recovered from distribution end-users balances the under-recovery in transmission revenue as a result of the price moderation.

6.2 Price setting for new transmission nodes

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 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 transmission use of system (**TUOS**) price and connection price. Western Power requires the prices to determine future revenues from the connection, and any associated capital contribution. The user requires the price and capital contribution for the purposes of project feasibility, and their internal approval processes.

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

Policy Statement – Transmission Use of System Price (TUOS)

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

1. Western Power will nominate a TUOS price consistent with all the principles described in this document based on the best available knowledge of the network parameters including asset values and expected load flows. This would also include necessary assumptions for maximum demand and utilisation at the new connection and also any other new or forecast connections.
2. That nominated nodal TUOS price will then be adjusted annually in line with the CMD weighted average TUOS price adjustment for all other load or generator transmission nodes (as applicable).
3. Once that connection point is established the nominated TUOS price (adjusted in accordance with step 2) will apply at the commencement of the access contract, with annual price adjustments at the start of each financial year in line with the annual price adjustment of other, existing transmission connections. (Thus, the nominated TUOS price will be consistent between all transmission connections at the same location.)
4. The TUOS price will be published once the connection point is commissioned.
5. Where another user subsequently connects to such a connection point the price that will apply will be the price applying to that connection point at the time.
6. The common service, metering and control system prices that apply in this circumstance will be the standard published prices.

Policy Statement – Transmission Connection Price

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

A connection that is unlikely to be shared by other users

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

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

The annual connection price is calculated to recover the expected operations and maintenance costs for the connection asset. <u>Western Power will make a reasonable estimate of the operations and maintenance costs of the connection asset and provide details of the estimate to the user.</u> Once the annual connection price has been determined for a particular connection point, the price is adjusted annually by the capitals consumer price index (**CPI**).

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

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

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

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