Appendix F.2

Tariff Structure Statement Technical summary

Proposed revisions to the access arrangement

1 February 2022

westernpower

Access Arrangement (AA) for the period
1 July 2022 to 30 June 2027

EDM 58784775

Tariff Structure Statement Technical summary

1 July 2023

Contents

1. Introduction

Western Power has prepared this technical summary to accompany its Tariff Structure Statement (TSS) Overview for the fifth access arrangement period (AA5) which covers 1 July 2022 to 30 June 2027. It is intended to be read in conjunction with the TSS Overview attached as Appendix F.1.

1.1 Summary of our new pricing framework

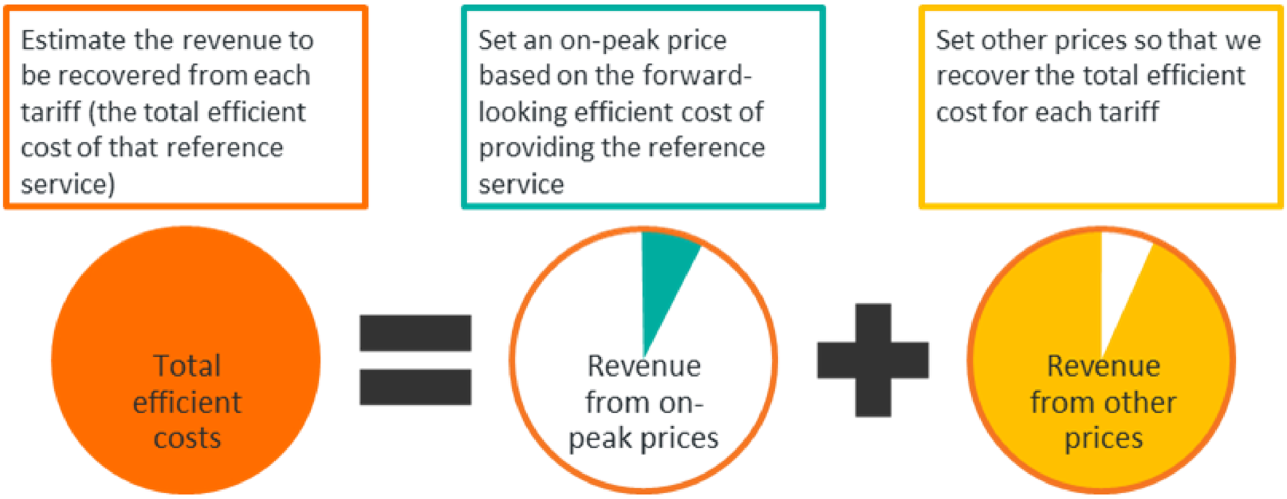
Recent changes to the Code require Western Power to apply a new framework for tariffs. The Code specifies a pricing objective that Western Power's reference tariffs:[1]

> *…should reflect the service provider's efficient costs of providing those reference services.*

We achieve this objective mainly through the use of a range of pricing principles reflecting widely-accepted economic principles, and insights and preferences collected from users and end-use customers.

We illustrate the essence of the overarching framework for setting efficient tariffs in Figure 1.1. The remainder of this section explains this process at a high level. A more detailed explanation is contained in section 4 of the TSS Overview.

Figure 1.1: Illustration of new tariff framework



A key focus of tariff reform is setting tariffs that reflect the forward-looking efficient cost of providing the relevant service. Section 2 explains how we estimate the forward-looking efficient cost for each tariff and convert that estimate into a price signal.

It is then necessary to set other variable and fixed charges for each tariff such that, when combined with prices based on forward-looking efficient costs, they:

- recover the total efficient cost (or target revenue) of providing the applicable reference service; and
- recover our target revenue approved by the ERA across all reference services.

These outcomes are achieved by allocating our efficient costs (as approved by the ERA) across our reference services, while ensuring that the efficient costs allocated to each tariff falls between the stand-alone and avoidable cost of providing that service. This approach is explained in further detail in this TSS technical summary.

[1] The Code, clause 7.3.

The requirement in the Code to prepare a TSS relates to distribution reference tariffs.[2] However, we also include a description of our approach to setting transmission reference tariffs and the structure of those tariffs in sections 3 and 5, respectively.

1.2 The structure of the TSS technical summary

The below table summarises the structure of this TSS technical summary:

Table 1.2: Structure of TSS technical summary

Section	Title	Description
Section Two	Forward-looking efficient cost	Describes how we estimate long run marginal cost and convert our estimates into an efficient price signal.
Section Three	Total efficient cost	Explains how we estimate the level of revenue to be recovered from each reference tariff.
Section Four	Stand-alone and avoidable cost	Describes how we estimate the upper and lower bound on the revenue to be recovered from each reference tariff.
Section Five	Tariff structures	Presents a detailed description of the structure of each reference tariff.
Section Six	Price setting for new transmission nodes	Summarises the price setting policy for new transmission nodes.
Section Seven	Reference tariff change forecast	Presents our methodology for calculating the weighted average annual price change for each reference tariff over AA5.
Section Eight	Compliance checklist	Confirms our compliance with the requirements in the Code relating to the TSS

[2] The Code, clause 7.1A.

2. Forward-looking efficient cost

In this section we explain in more detail the approach that we apply to comply with the requirement that:[3]

> *Each reference tariff must be based on the forward-looking efficient costs of providing the reference service to which it relates to the customers currently on that reference tariff.*

Signalling to customers the future network costs that can be avoided by changes in the way they use the network is the foundation to efficient network pricing.

The forward-looking efficient cost of providing a service is reflected in the economic concept of marginal cost. In economics, the marginal cost of a service is the additional cost caused or avoided by a small change in the production of a service.

By way of example, the application of a price based on marginal cost in the on-peak period indicates to customers the additional network costs caused by further use of the network during the on-peak period. The efficient outcomes may then include:

- a customer shifting their load outside of the on-peak period, which results in a cost saving for them and all other customers;
- a customer identifying that a behind-the-meter investment, e.g., in a battery or more energy efficient appliances, can provide the same amenity at a lower cost; and
- a customer that values their use of the network at those times very highly continuing to use the network during the on-peak period, which signals to Western Power that they are willing to pay for the future costs they are causing and that they value further investment in the network.

2.1 Long run or short run marginal cost?

Marginal cost can be evaluated over a short or long horizon, i.e., short run marginal cost (SRMC) and long run marginal cost (LRMC).

SRMC includes all costs caused by further use of the network, except the costs of additional network capacity. This means that SRMC includes the cost of congestion such that, when demand approaches network capacity, SRMC will increase to a level that is high enough to reduce demand to a level that can be served by existing network capacity.

Although prices based on SRMC are therefore effective at managing existing capacity, they give rise to extremely volatile price signals for customers.

In contrast to SRMC, LRMC reflects only the cost of additional network capacity that is required or avoided by a change in demand, evaluated over an extended horizon. This evaluation of network costs and demand over an extended horizon produces estimates of LRMC that are much more stable than SRMC.

It follows that prices based on LRMC are relatively more stable and are therefore more effective at promoting efficient network use and investment decisions by customers over the medium to long term, as well as in managing any customer bill impacts during the transition to more efficient pricing.

Accordingly, Western Power proposes to set prices based on LRMC, rather than SRMC. This is consistent with the approach applied by all other electricity network businesses in Australia.

[3] The Code, clause 7.3G.

2.2 Consideration of how long run marginal costs vary across the network

The long run marginal cost of providing reference services varies by location, depending on the availability of network capacity, whether demand is increasing or decreasing and expected future costs.

Consistent with our current approach, we are not implementing locational pricing for customers using less than 1MVA of electricity. This also reflects the requirement in the Code that:[4]

> *The tariff applying to a standard tariff user in respect of a standard tariff exit point must not differ from the tariff applying to any other standard tariff user in respect of a standard tariff exit point as a result of differences in the geographic locations of the standard tariff exit points.*

We have therefore not derived location-specific estimates of LRMC.

2.3 Deriving an estimate for each reference tariff

Clause 7.3G of the Code requires each reference tariff be based on the LRMC of providing the relevant reference service to the customers currently on that reference tariff.

For similar customers, the future costs caused by further use of the network will be the same, irrespective of the reference tariff they are on. For the purpose of estimating LRMC, we have therefore grouped together reference tariffs that apply to customers whose decisions are likely to result in similar, if not the same, future costs. This is consistent with the approach applied in the National Electricity Market (NEM), since attempting to derive more granular estimates of LRMC would not elicit any further information.

For example, further use of the network by residential customers during periods of peak demand is likely to result in a similar level of future costs, regardless of which residential reference service they use.

In the context of prices that are not locational, the principal determinant of the LRMC applying during the on-peak period is the level of the network to which a customer is connected. By way of example:

- further use of the network by a customer connected to the high voltage network may increase the future cost of the high voltage network, but leaves unchanged the future cost of the low voltage network; whereas
- further use of the network by a customer connected to low voltage network during periods of peak demand will typically contribute to future costs on both the low and high voltage networks.

For the purpose of estimating LRMC, we therefore group together reference tariffs by reference to the level of the network to which those customers connect, i.e., high voltage and low voltage. We also estimate LRMC for residential and business customers separately at the low voltage level.

This reflects that further use of the network by residential customers (as an example) during periods of peak demand is likely to result in a similar level of future costs, regardless of what reference tariff they are on.

Our approach is consistent with that applied by all network businesses in the NEM, which estimate LRMC by grouping together tariffs based on the relevant level of the network (sometimes with further distinctions depending on the network's circumstances).

[4] The Code, clause 7.7.

Table 2.1: Grouping of reference tariffs for estimating LRMC

Low voltage residential	Low voltage business	High voltage
RT1	RT2	RT5
RT3	RT4	RT7
RT13	RT6	RT39
RT15	RT8	RT41
RT17	RT14	
RT19	RT16	
RT21	RT18	
RT34	RT20	
RT36	RT22	
	RT35	
	RT37	
	RT38	
	RT40	

2.4 Estimation methodology

There are two commonly considered approaches for the estimation of LRMC:

- the perturbation approach, which is also known as the Turvey approach; and
- the average incremental cost (AIC) approach.

The AIC approach is adopted by almost all network businesses in the NEM. It involves estimating LRMC equal to the average change in projected operating and capital expenditure attributable to future changes in demand.

The perturbation approach is more theoretically pure, but comes with a significant implementational burden since its application necessitates engineering assessments of how future network costs would change if demand was altered (or perturbed) by a fixed, permanent increment.

Consistent with the approach applied in the NEM, we estimate LRMC based on the AIC approach.

2.4.1 Implementation of average incremental cost approach

For the purpose of setting our on-peak prices, we estimate LRMC as follows:

$$\frac{\text{Net present value of network costs caused by growth in demand}}{\text{Net present value of demand growth}}$$

We calculate the net present value of future growth-related network costs by:

- evaluating future capital programs over a ten year period to determine those caused, in whole or part, by growth in demand;

- calculating the value of growth-related capital expenditure annualised over the expected life of the asset;[5]
- calculating the cumulative value of annualised growth-related capital expenditure in each of the ten years;
- evaluating the value of operating expenditure associated with those growth-related capital projects;
- estimating the extent to which growth-related capital and operating expenditure are driven by each group of customers; and
- calculating the present value of future growth-related expenditure caused by that group of customers.

We calculate the net present value of demand growth by:

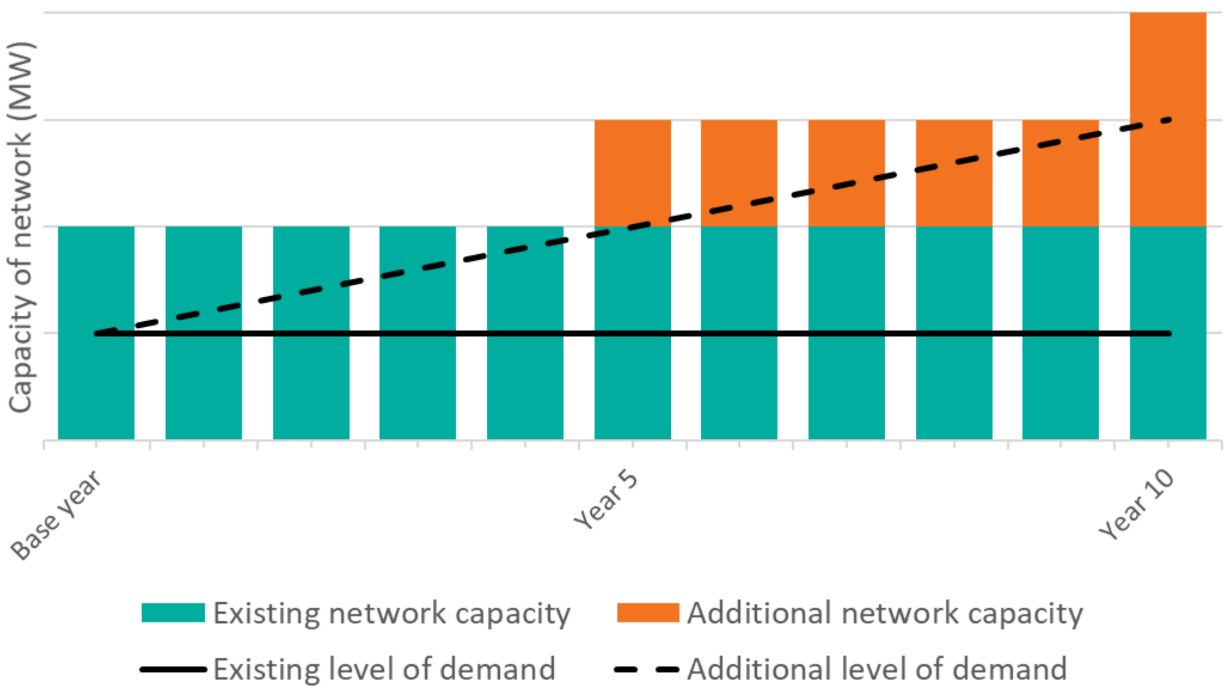
- evaluating the additional demand met by Western Power's network over the ten year period;
- estimating the cumulative increase of demand for each group of customers; and
- calculating the present value of additional demand caused by that group of customers.

We calculate the LRMC for each group of customers by dividing the present value of growth-related expenditure by the present value of additional demand.

We calculate the present value of expenditure and demand (as well as annualised capital expenditure) based on our proposed regulatory WACC, i.e., an average of 4.73 per cent across the AA5 period.

Figure 2.1 presents an illustrative example of the application of the AIC approach.

Figure 2.1: Illustrative example of the AIC approach for LRMC estimation



In this illustrative example, the growth related capital and operating expenditure is the network expenditure that is associated with the increase in network capacity, indicated by the orange bars. Demand

[5] This accounts for the end-effects that arise from the use of a ten year estimation period, where asset lives extend far beyond ten years, ie, each dollar of capital expenditure serves demand over a period much longer than ten years. Failing to account for these end effects would over-estimate LRMC.

growth is represented by the difference between the dashed black line, being forecast demand, and the solid black line, being a reference point for the level of demand in the base year.

The AIC approach divides the present value of the expenditure associated with the orange bars by the present value of the increase in the dashed black line above the solid black line.

2.4.2 Results of our analysis

We present below our estimates of LRMC by reference to the voltage level to which customers using each reference service connect.

Table 2.2: Estimates of LRMC

Applicable reference tariffs	LRMC estimate
Low voltage residential	$22.70 per kW
Low voltage business	$23.65 per kW
High voltage	$24.70 per kW

Our reasonably similar estimates of LRMC on the high and low voltage network reflect that the majority of growth-related expenditure relates to the high voltage network, with the consequence that an incremental unit of demand on either the high or low voltage network results in a similar level of future costs.

2.5 Conversion of LRMC to prices

The LRMC of providing reference services will vary considerably throughout the day. Therefore, efficiency is promoted by aligning our LRMC based price signal with the times of greatest network utilisation.

Outside of periods of very high demand, additional demand typically does not cause an increase in our future costs, as it can be served by existing excess capacity. At these times, LRMC is very close to zero.

On the other hand, when the network is at or approaching a constraint, additional demand increases future costs. For example, to continue to provide safe and reliable network services we may need to undertake new investment in network capacity, or bring forward the timing of a pre-planned expansion.

Since our estimate of LRMC is based on meeting demand at times of greatest network utilisation, we signal LRMC to customers by applying a LRMC-based price during the on-peak period.

It is also relevant to note that some of our reference tariffs do not include an on-peak energy or on-peak demand price. For example, this is the case for our residential anytime energy tariff.

For these tariffs, the efficiency benefits of a LRMC-based price, smoothed across the entire day, is minimal. Consistent with the approach applied by other networks in the NEM, we therefore add a mark-up to the LRMC-based price to assist in recovering our total efficient cost. This is also the case for our low and high voltage metered demand and low and high voltage contracted maximum demand customers.

The LRMC-based price for an anytime energy price is calculated as:

$$\text{LRMC anytime energy price (\$/kWh)} = \frac{\text{LRMC(\$/kW)}}{\text{Number of hours in a year}}$$

The LRMC-based price for on-peak energy prices is calculated as:

$$\text{On-peak energy price (\$/kWh)} = \frac{\text{LRMC(\$/kW)}}{\text{Number of hours defined as 'on-peak' in a year}}$$

The LRMC-based price for on-peak demand prices is calculated as:

$$\text{On-peak demand price (\$/kW)} = \frac{\text{LRMC(\$/kW)}}{\text{Number of billing periods in a year}}$$

Section 4.1 of the TSS Overview explains the considerations that we apply to derive our final on-peak prices.

3. Total efficient cost

In this section we explain our cost allocation methodology for both distribution and transmission services. The purpose of these methodologies is to appropriately estimate the total efficient cost of providing each reference service so that the revenue recovered from each reference tariff reflects the total efficient cost of providing the relevant service.

Although economic principles establish this upper and lower bound on the level of revenue to be recovered from each reference tariff (the total efficient cost), they do not identify a unique, efficient allocation for each reference tariff.

This is reflected in the significantly different approaches adopted by networks in the NEM. For example, the approved approach of the electricity network provider in the Australian Capital Territory, Evoenergy, is based on the allocation of costs in the previous year,[6] whereas Ausgrid (a network service provider in New South Wales) approved approach is:[7]

> *…based on their relative contribution to maximum demand, a key driver of our efficient costs.*

We calculate the total efficient cost of providing each reference service to customers based on the value of the assets they use and the extent to which they use those assets, relative to customers using other reference services.

We consider these foundational principles to be a fair and reasonable basis for the allocation of our efficient costs.

We operate both a distribution and transmission network. Customers connected to the transmission network use only the transmission network, whereas providing services to customers connected to the distribution network requires the use of both the transmission and distribution networks.

Distribution costs are therefore allocated among distribution reference services only, whereas transmission costs are allocated to both distribution and transmission reference services.

Table 3.1 indicates how total costs are allocated between distribution and transmission customers and the role played by the cost allocation methodology.

Table 3.1: Allocation of distribution and transmission costs to reference services

	Distribution reference services	Transmission reference services
Distribution costs	Determined by the distribution cost allocation methodology.	Not relevant
Transmission costs	Share of transmission costs determined by the transmission cost allocation methodology. How these costs are shared across distribution customers is determined by the distribution cost allocation methodology.	Determined by the transmission cost allocation methodology.

The distribution cost allocation methodology and the transmission cost allocation methodology are explained below.

[6] Evoenergy, *Attachment 1: Revised Proposed Tariff Structure Statement*, November 2018, p 35.

[7] Ausgrid, *Revised Proposal Attachment 10.01 Tariff Structure Statement*, January 2019, p 69.

3.1 Allocation of distribution costs to reference tariffs

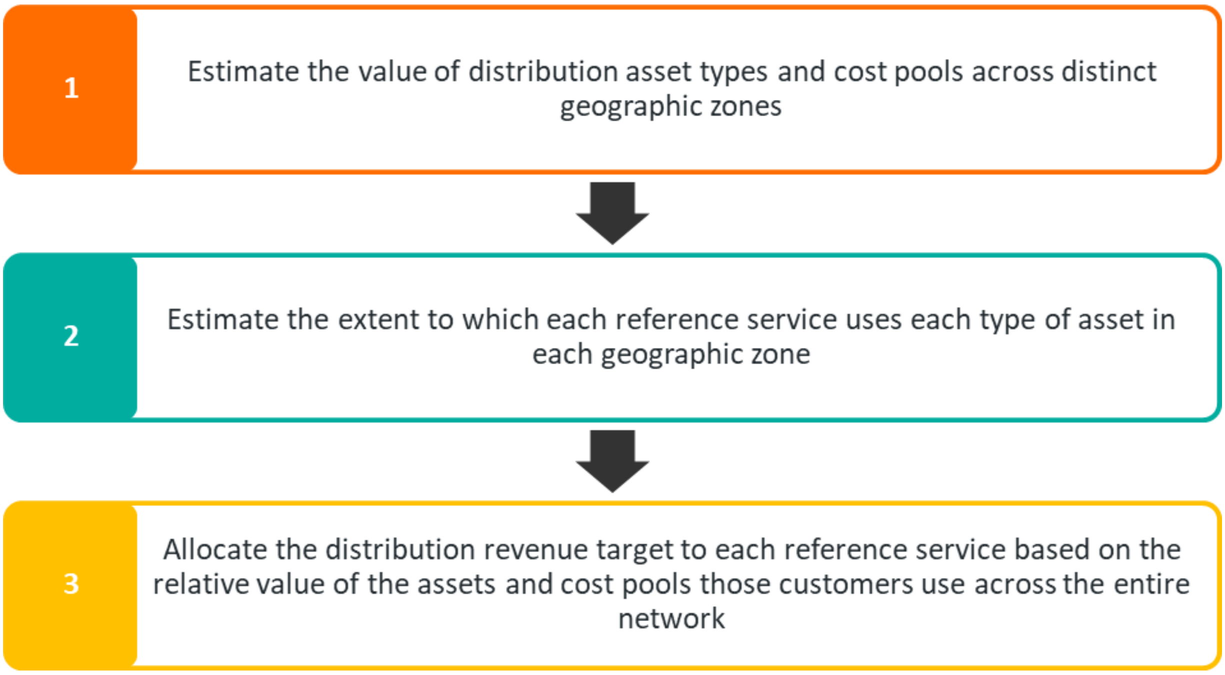
This section details the cost allocation methodology as it pertains to Western Power's distribution system.

Clause 7.3 of the Code presents a pricing objective:[8]

> *…that the reference tariffs that a service provider charges in respect of its provision of reference services should reflect the service provider's efficient costs of providing those reference services.*

We calculate the total efficient cost of providing each reference service based on the value of the assets and services used by those customers and the extent to which they use those assets and services, relative to customers using other reference services. This process is detailed in Figure 3.1.

Figure 3.1: Distribution services cost allocation flow chart



Fundamental to our methodology is the segmenting of Western Power's distribution network into two main components, namely:

- six distribution asset types and 'cost pools',[9] relating to function and voltage level; and
- five geographic zones.

We include a detailed description and explanation of each of the three steps from Figure 3.1 below.

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

The first step of our 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.

[8] The Code, clause 7.3.

[9] We use the term 'cost pool' 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.

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 customers and 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;
- metering assets; and
- 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.

We have defined five geographic zones for which the distribution cost of service to, and downstream from, the zone substation is similar. 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; 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 connected downstream customers and therefore provides a different combination of reference services to reflect these customer 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 customer.

Asset valuation

We have estimated 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.[10]

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.

Further, we have 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 poses very little influence on the resulting valuations.

Importantly, 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, we have a high degree of visibility over the segmentation of the distribution network by asset type and geographic zone.

Table 3.2 presents the resulting allocation of total network value across asset types and geographic location.

Table 3.2: Relative value of assets by asset type and geographic zone

Geographic zone	Transformers	High voltage assets	Low voltage assets
CBD	*0.5%*	*0.4%*	*0.2%*
Urban	*23.8%*	*13.5%*	*2.8%*
Rural	*4.0%*	*25.6%*	*1.3%*
Mining	*0.0%*	*0.7%*	*0.0%*
Mixed	*8.6%*	*17.0%*	*1.6%*

Streetlight, metering and admin

The total efficient costs of providing streetlight, metering and admin services is 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 particular 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 Figure 3.1.

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;

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

- approved operating expenditure; and
- any indirect cost allocation – including a portion of overall tax and the recovery of deferred revenue.

3.1.2 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 customers 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 customer 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 customers 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 customers for each reference service. There are three ways in which the relative use of the distribution network by a group of customers can be calculated, namely the:

- contribution of customers using each reference service to system-wide maximum demand, which incorporates the diversity in maximum demand for different types of reference services;[11]
- contribution of customers using each reference service to total energy consumption; and
- total number of customers using each reference service.

We allow for the relative use of each distribution asset type and cost pool by customers 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 customers using each reference service whereas the relative use of network assets, such as transformers and the high or low voltage networks, uses the contribution to system-wide maximum demand. This ensures that costs with different characteristics are able to be 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 reference services for low voltage connected customers; and
- the total number of customers for streetlight, metering and administrative services.

[11] We are only able to observe the contribution to system-wide maximum demand for customers with interval meters, which is currently only a modest proportion of our total customer base. Using the collection of customers with interval meters we are 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 our estimate for the contribution to maximum demand from the collection of customers using each reference service. We envision that this methodology will become more precise over time as the rollout of interval meters increases.

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.

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 customers . For instance, load shifting of residential customers away from the traditional demand peak in the evening through use of DER would result in a lower contribution to system maximum demand for these customers. As a result, the allocation of costs to these customers will decline to reflect their reduced contribution to the incursion of costs.

3.1.3 Step 3 – allocating 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 customers and the extent to which they use those assets and services, relative to customers using 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. As such, the allocation that links network costs to different types of customers. In step 3, the total distribution revenue target is assigned to each distribution reference service using this allocation.

Because streetlight assets and services are only used by the streetlight distribution reference service, the entire streetlight cost of service calculation explained on page 12 is allocated to the streetlight reference service. This apportioning of total costs occurs separately to the allocation of the other costs to the other reference services.

The process by which total distribution target revenue is allocated to 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 allocated to reference services using the relative allocation methodology described above; and
- the streetlight cost of service is allocated 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 customers using each distribution reference service.

3.1.4 Transmission revenue recovered from distribution customers

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 connected customers. 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 customers 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 customers 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 3.3 presents an indicative breakdown of transmission service revenue by geographic zone.

Table 3.3: Relative value of transmission service revenue to be recovered from distribution customers

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

The allocation of the pass through of transmission service revenue to distribution reference services proceeds in the same manner as for transformer and high voltage assets in steps 2 and 3. That is, the allocation of transmission service revenue to each distribution reference service is based on the relative contribution to system-wide maximum demand by each reference service.

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 customers is reflective of this new cost allocation methodology.

3.2 Allocation of transmission costs

This section details the cost allocation methodology as it pertains to Western Power's transmission system.

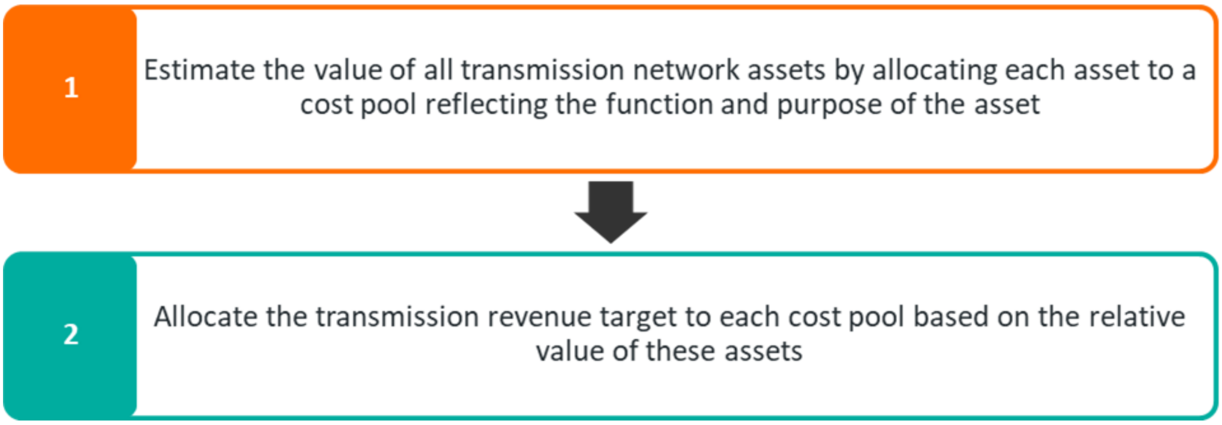
The cost allocation methodology for the transmission system is a process by which Western Power's total costs for transmission system services is recovered from:

- each individual transmission connected customer; and
- all distribution system connected customers, as these customers also use, and therefore must contribute to the cost recovery of, the transmission system.

Similarly to the distribution cost allocation methodology, transmission costs are allocated based on the relative value of assets and the relative use of these assets by customers using each transmission reference service. This is achieved through the use of location specific and customer specific prices for some components of transmission reference tariffs.

The allocation of transmission costs to transmission reference services follows the high level process detailed in Figure 3.2.

Figure 3.2: Transmission services cost allocation flow chart



The remainder of this section provides a detailed description and explanation of the steps presented in Figure 3.2.

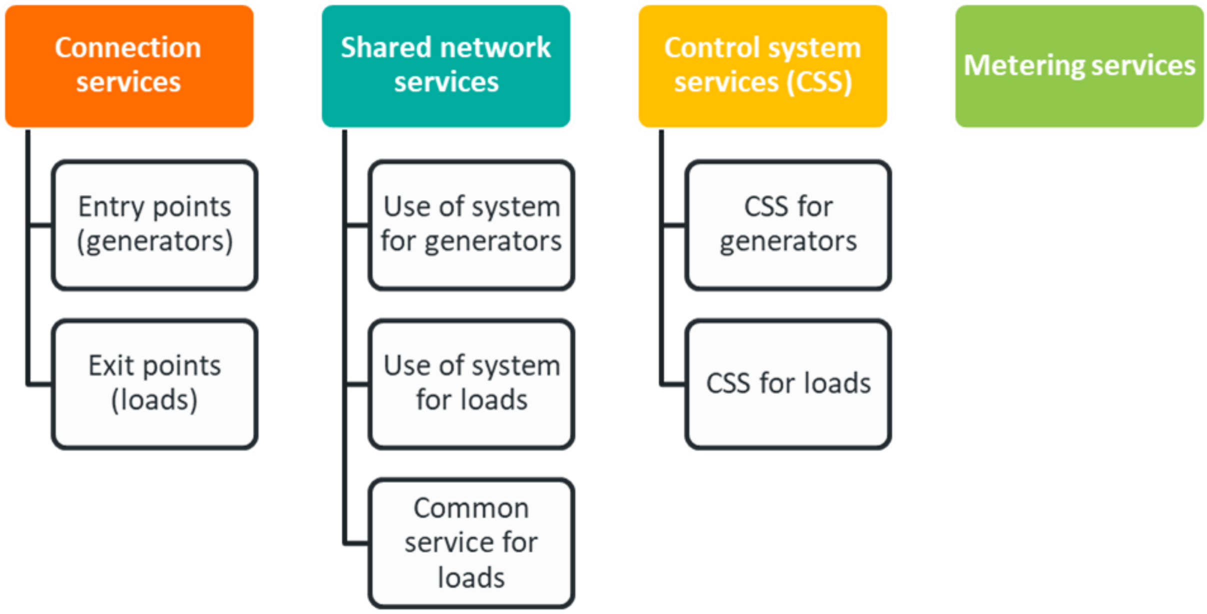
3.2.1 Step 1 - definition of transmission service cost pools

Fundamental to the transmission cost allocation methodology is the establishment of cost pools to which transmission revenue is allocated. In the context of the transmission network cost allocation methodology, these 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 customers – allocated to the connection services cost pool;
- voltage control services – allocated 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 customer – allocated to the shared network services cost pool;
- providing control services across the transmission network, such as SCADA assets and SCADA control systems –allocated to the control system services (CSS) cost pool; and
- metering for transmission connected customers –allocated to the metering services cost pool.

The transmission service cost pools are presented in Figure 3.3.

Figure 3.3: Transmission service cost pools



The value of transmission network assets are 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 cost allocation for metering and CSS assets is determined using the building block approach, similar to that used in establishing target revenue for distribution and transmission services.

In addition, the allocation of transmission network assets and transmission cost of service to cost pools is further segmented by an allocation to the two distinct transmission customer types, generators and loads. Table 3.4 presents the nature by which the cost pools are further segmented to generators and loads.

Table 3.4: Allocation of transmission cost pools between loads and generators

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

Transmission cost pools	Loads (exit points)	Generators (entry points)
Common service (shared network services)	• 30 per cent of the total value of shared network service assets • Two thirds 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

3.2.2 Step 2 – allocate transmission target revenue to transmission cost pools

The result of step 1 is an allocation of the combined value of all assets in the transmission network to each cost pool. In step 2, the allocation of total network valuation into cost pools is used to allocate transmission target revenue to these same cost pools. This determines the targeted amount of revenue to be recovered from each component of transmission reference tariffs.

In order to allocate transmission target revenue across cost pools, the following information is required:

- the total value of assets associated with each transmission cost pool, denoted as $V_{\text{Cost Pool}}$, 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 3.5 presents the process by which the allocation of asset values to cost pools is converted to an allocation of total transmission target revenue to these cost pools. 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 revenue allocated to each cost pool will be equal to the transmission target revenue each year.

Table 3.5: Calculation of transmission cost allocation

Transmission cost pool	Cost pool asset value	Revenue allocation
Connection (exit)	$V_{\text{Exit connection}}$	$V_{\text{Exit connection}} \times \text{RR}$
Connection (entry)	$V_{\text{Entry connection}}$	$V_{\text{Entry connection}} \times \text{RR}$
Use of system (exit)	$V_{\text{Exit UOS}}$	$V_{\text{Exit UOS}} \times \text{RR}$
Use of system (entry)	$V_{\text{Entry UOS}}$	$V_{\text{Entry UOS}} \times \text{RR}$
Common service	V_{CS}	$V_{\text{CS}} \times \text{RR}$
CSS (exit)	$V_{\text{Exit CSS}}$	$V_{\text{Exit CSS}}$
CSS (entry)	$V_{\text{Entry CSS}}$	$V_{\text{Entry CSS}}$
Metering	V_{Metering}	V_{Metering}

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

Table 3.6 presents the relative allocation of total transmission revenue to each of the cost pools, which underpins the allocation of transmission target revenue each year.

Table 3.6: Relative allocation of transmission service revenue to cost pools

Transmission cost pool	Relative cost allocation share
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%*

3.2.3 Implementation considerations for transmission service cost allocation

Given the small number of transmission customers relative to distribution customers, moderate changes in target revenue or other inputs to the cost allocation methodology may lead to larger price changes for individual transmission customers relative to distribution customers. 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 customer.

For these reasons, we implement a form of price moderation within the transmission pricing model that can introduce a variance between the cost allocation and the recovered revenue across the transmission cost pools. This variance may require a reallocation 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 does not explicitly moderate changes in CSS prices and so the cost pool allocation for CSS services is typically recovered each year.

Similar to connection prices, Western Power sets metering prices for customers connected to the transmission network each year to recover the costs of providing metering services to these customers, i.e., 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.

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 customers. We therefore include 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, we moderate the annual change in common service prices to ensure control over the stability of total prices for transmission connected customers.

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 customers.

As part of the transmission pricing methodology, the pass through to distribution customers 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 customers balances the under-recovery in transmission revenue as a result of the price moderation.

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

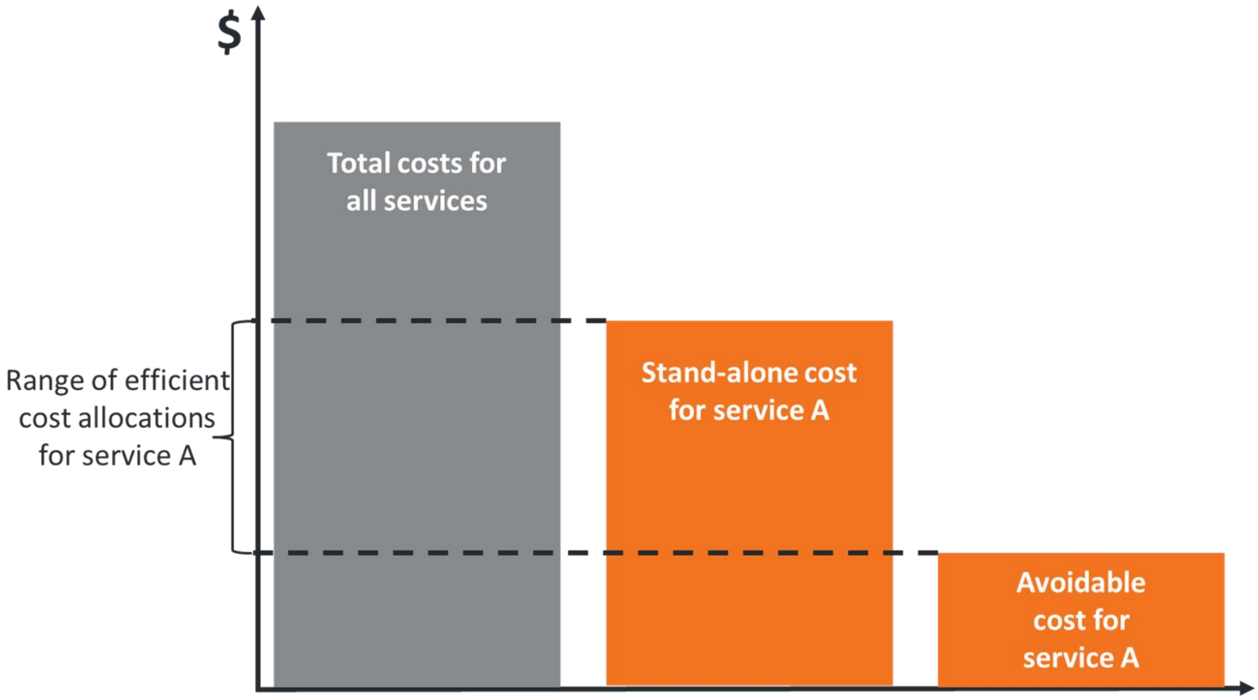
The economic concepts of stand-alone and avoidable cost reflect the principle that the amount recovered from users of any one service in a group of services using shared assets should be:

- no more than the efficient cost of providing that service alone (the stand-alone cost) – if those customers 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 customers were charged less than the avoidable cost then the business would not be recovering the costs incurred to supply the customers, and the shortfall in revenue would have to be recovered from other customers.

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 customers 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 customers 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.

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

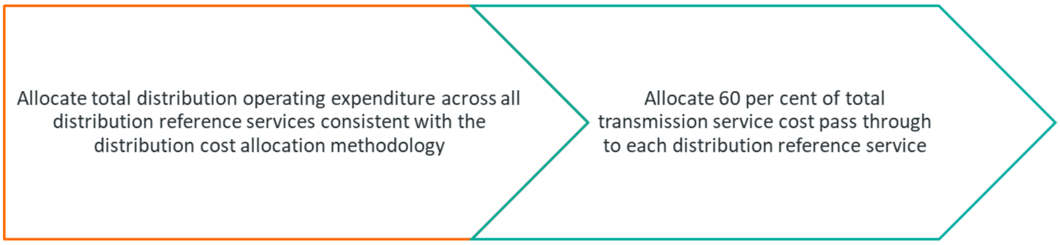
The estimation process for stand-alone and avoidable costs are discussed separately, commencing with the process for avoidable cost.

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 section 3.1, we have developed a methodology for allocating total distribution costs to distribution reference services. Our 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, we assume 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.

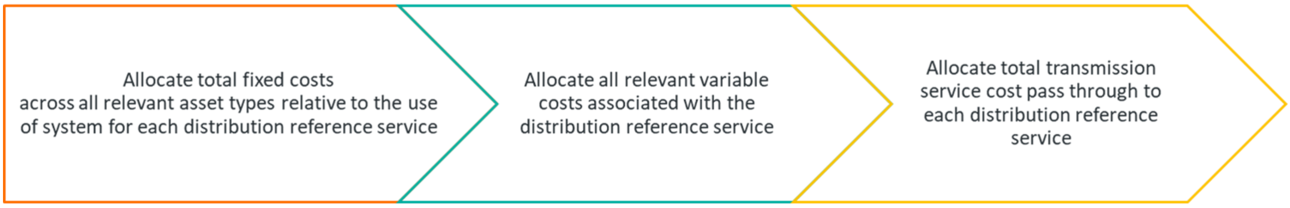
With regards to transmission connected customers, many components of total operating expenditure will still be necessary if certain services are not provided. In particular, the only component of total transmission operating expenditure that is avoidable is operating expenditure associated with network 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 section 3.1, we have 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 customers using that 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 connected customers, 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
A14 – 3 Part Time of Use Demand (Residential) Exit Service C11 – 3 Part Time of Use Demand (Residential) Bi-directional Service	RT19

Reference service	Reference tariff
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[12]
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
A18 – Super Off-peak Energy (Residential) Exit Service	RT34
A19 – Super Off-peak Energy (Business) Exit Service	RT35
C16 – Super Off-peak Energy (Residential) Bi-directional Service	RT36
C17 – Super Off-peak Energy (Business) Bi-directional Service	RT37
C18 – Low Voltage Distribution Storage Service	RT38
C19 – High Voltage Distribution Storage Service	RT39
C20 – Transmission Storage Service	TRT3
C21 – Low Voltage Electric Vehicle Charging Service	RT40
C22 – High Voltage Electric Vehicle Charging Service	RT41

As stated in section 3 of the TSS Overview, the structure of a reference tariff refers to the design of its charging components, which principally includes:

- the form of the charging components, e.g., fixed charges, variable energy charges, variable demand charges and/or capacity-based charging components; and

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

- the particular specification of those charging components, e.g., whether or not different variable charges apply at different times of the day.

We acknowledge that the structure of some existing tariffs is different to the structure of new tariffs to be included in AA5. This is primarily the case for the new time of use energy tariffs, which contain a super off-peak period that is not a defined charging window in most existing time of use energy tariffs. Any existing reference tariff that is superseded by a new reference tariff is classified as a 'transitional' reference tariff.

Accordingly, we will provide the existing customers 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. This is consistent with our approach from previous access arrangements.

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)	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	✓	✓		✓		✓												✓		
RT5 - HV Metered Demand	No	✓	✓							✓	✓	✓		✓					✓		
RT6 - LV Metered Demand	No	✓	✓							✓	✓	✓		✓					✓		
RT7 - HV CMD	No	✓	✓										✓	✓				✓	✓	✓	

TARIFF	TARIFF COMPONENTS																				
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	✓	✓		✓	✓	✓												✓		
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 (Residential) Exit - new	No	✓	✓		✓	✓	✓		✓										✓		
RT35 – Super Off-peak Energy (Business) Exit - new	No	✓	✓		✓	✓	✓		✓										✓		
RT36 – Super Off-peak Energy (Residential) Bi-directional - new	No	✓	✓		✓	✓	✓		✓										✓		
RT37 – Super Off-peak Energy (Business) Bi-directional - new	No	✓	✓		✓	✓	✓		✓										✓		
RT38 – Low Voltage Distribution Storage - new	No	✓	✓		✓	✓	✓		✓										✓		

TARIFF	TARIFF COMPONENTS																				
RT39 – High Voltage Distribution Storage - new	No	✓	✓							✓	✓	✓		✓					✓		
RT40 – Low Voltage Electric Vehicle - new	No	✓	✓							✓	✓	✓		✓					✓		
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																				✓
TRT1 – Transmission Exit	No		✓										✓			✓	✓	✓	✓		
TRT2 – Transmission Entry	No		✓										✓			✓		✓	✓		
TRT3 – Transmission Storage - new	No		✓										✓			✓	✓	✓	✓		

We present a detailed explanation of the structure of each transmission and distribution reference tariff below. For the purpose of this description we have grouped reference tariffs for:

- transmission reference services;
- distribution reference services for residential customers;

- distribution reference services for small and medium business customers;
- distribution reference services for large business customers; and
- other distribution reference services.

5.1 Transmission reference services

5.1.1 Transmission load tariff (TRT1)

Our load tariff for transmission customers consists of multiple location specific, cost-reflective prices. This tariff is individually calculated for each transmission connected load and so can differ in structure between customers.

In general, the transmission load reference tariff consists of:

- a fixed, daily charge for access to our network that reflects the costs of providing connection assets;
- a fixed, daily metering charge per meter;
- variable charges that apply to the contracted maximum demand (CMD) of the individual customer that reflect their use of system, contribution to common services and use of control system services; and
- excess network usage charges (ENUC) calculated in accordance with our ENUC principles for transmission connections.

5.1.2 Transmission generator tariff (TRT2)

Similar to our transmission load tariff, our generator tariff for transmission customers consists of multiple location specific, cost-reflective prices. This tariff is individually calculated for each transmission connected generator and so can differ in structure between customers.

In general, the transmission generator reference tariff consists of:

- a fixed, daily charge for access to our network that reflects the costs of providing connection assets;
- a fixed, daily metering charge per meter;
- variable charges that apply to the declared sent our capacity (DSOC) of the individual customer that reflect their use of system and use of control system services;[13] and
- ENUC calculated in accordance with our ENUC principles for transmission connections.

5.1.3 Transmission storage service tariff (TRT3)

We are introducing a new tariff for transmission-connected storage systems in AA5 that, like our existing transmission reference tariffs, is individually calculated for each transmission connected storage device and consists of location specific, cost-reflective prices. Consistent with our other storage service tariffs, transmission storage devices will not be subject to generation or export based charges and will be treated similar to existing loads connected to the transmission network.

This tariff comprises:

- a fixed, daily charge for access to our network that reflects the costs of providing connection assets;
- a fixed, daily metering charge per meter;

[13] The control system services variable charge for transmission generators is applied to their nameplate capacity, rather than their DSOC.

- variable charges that apply to the contracted maximum demand (CMD) of the individual customer that reflect their use of system, contribution to common services and use of control system services; and
- ENUC calculated in accordance with our ENUC principles for transmission connections.

5.1.4 ENUC principles

An additional charge applies to transmission connected customers, both loads and generators, where the peak half-hourly demand exceeds the nominated CMD, for loads, or DSOC, for generators, during the billing period except where Western Power deems the power in excess of CMD or DSOC was required for power system reliability and security purposes.

5.2 Distribution reference services – residential customers

5.2.1 Anytime energy tariffs (RT1 and RT13)

Our anytime energy tariffs are distinct from the other tariff options for residential customers in that they include a single variable charge that does not change throughout the day.

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

These reference tariffs comprise:

- a fixed, daily charge for access to our network;
- a variable charge that applies to each kWh of energy imported from our network; and
- a fixed, daily metering charge that reflects the metering reference service we provide to these customers.

5.2.2 Time of use energy tariffs (RT3 and RT15)

The structure of our time of use energy tariffs are similar to our anytime energy tariffs, with one important distinction, the applicable variable charge varies throughout the day.

We offer two time of use energy tariffs for residential customers, one for residential customers that only import energy from our network (RT3) and another for residential customers that both import and export energy from our network (RT15). The structure of these two tariffs is the same.

These reference tariffs comprise:

- a fixed, daily charge for access to our network;
- a distinct variable energy charge that applies to each kWh of energy imported from our network during each of the on- and off-peak periods; and
- a fixed, daily metering charge that reflects the metering reference service we provide to these customers.

The on- and off-peak periods applicable to the residential time of use energy charges (RT3 and RT15) are presented in

Table 5.3.

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)

The structure of our three part time of use energy tariff is similar to our time of use energy tariffs, with an additional charging period defined during the day, i.e., the shoulder period.

We offer a single three part time of use energy tariff for residential customers, available to residential customers that only import energy from our network and to those that both import and export energy from our network. The structure of the tariff is the same for both types of residential customers.

This reference tariff comprises:

- a fixed, daily charge for access to our network;
- a distinct variable energy charge that applies to each kWh of energy imported from our network during each of the on-peak, shoulder and off-peak periods; and
- a fixed, daily metering charge that reflects the metering reference service we provide to these customers.

The on-peak, shoulder and off-peak periods applicable to the residential three part time of use energy tariff (RT17) are presented 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)

The structure of our three part time of use demand tariff is similar to our three part time of use energy tariff, with an additional tariff component that applies to the customer's maximum demand in a half-hour period during the on-peak period.

We offer a single three part time of use demand tariff for residential customers, available to residential customers that only import energy from our network and to those that both import and export energy from our network. The structure of the tariff is the same for both types of residential customers.

This reference tariff comprises:

- a fixed, daily charge for access to our network;

- a variable demand based charge that applies to the maximum demand in a half-hour period within the on-peak period measured over a billing period (expressed in kW);[14]
- a distinct variable energy charge that applies to each kWh of energy imported from our network during each of the on-peak, shoulder and off-peak periods; and
- a fixed, daily metering charge that reflects the metering reference service we provide to these customers.

The on-peak, shoulder and off-peak periods applicable to the residential three part time of use demand tariff (RT19) are presented in Table 5.5. We note that 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)

The structure of our multi part time of use energy tariff is similar to our three part time of use energy tariff, with an additional charging period defined during the day, i.e., the overnight period.

We offer a single multi part time of use energy tariff for residential customers, available to residential customers that only import energy from our network and to those that both import and export energy from our network. The structure of the tariff is the same for both types of residential customers.

This reference tariff comprises:

- a fixed, daily charge for access to our network;
- a distinct variable energy charge that applies to each kWh of energy imported from our network during each of the on-peak, shoulder, off-peak and overnight periods; and
- a fixed, daily metering charge that reflects the metering reference service we provide to these customers.

The on-peak, shoulder, off-peak and overnight periods applicable to the residential multi part time of use energy tariff (RT21) are presented 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

[14] The demand charge is applied to each day of the billing period over which it is measured.

5.2.6 Super off-peak energy tariffs (RT34 and RT36)

The structure of our new super off-peak energy tariff is similar to our existing/transitional multi part time of use energy tariff (RT21), with the 'overnight' period replaced with a 'super off-peak' period in the middle of the day and with different time definitions for the on-peak, shoulder and off-peak periods.

We offer a super off-peak energy tariff, which is a multi-part time of use energy tariff with a super off peak period, to residential customers that only import energy from our network (RT34) and to those that both import and export energy from our network (RT36). The structure of the tariff is the same for both types of residential customers.

These reference tariffs comprise:

- a fixed, daily charge for access to our network;
- a distinct variable energy charge that applies to each kWh of energy imported from our network during each of the on-peak, shoulder, off-peak and super off-peak periods; and
- a fixed, daily metering charge that reflects the metering reference service we provide to these customers.

The on-peak, shoulder, off-peak and super off-peak periods applicable to the residential multi part time of use energy tariff (RT34 and RT36) are presented in Table 5.7.

Table 5.7: Definition of charging windows for RT34 and RT36

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 customers

5.3.1 Anytime energy tariffs (RT2 and RT14)

Our anytime energy tariffs are distinct from the other tariff options for business customers in that they include a single variable charge that does not change throughout the day.

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

These reference tariffs comprise:

- a fixed, daily charge for access to our network;
- a variable charge that applies to each kWh of energy imported from our network; and
- a fixed, daily metering charge that reflects the metering reference service we provide to these customers.

5.3.2 Time of use energy tariffs (RT4 and RT16)

The structure of our time of use energy tariffs are similar to our anytime energy tariffs, with one important distinction, the applicable variable charge varies throughout the day.

We offer two time of use energy tariffs for business customers, one for business customers that only import energy from our network (RT4) and another for business customers that both import and export energy from our network (RT16). The structure of these two tariffs is the same.

These reference tariffs comprise:

- a fixed, daily charge for access to our network;
- a distinct variable energy charge that applies to each kWh of energy imported from our network during each of the on- and off-peak periods; and
- a fixed, daily metering charge that reflects the metering reference service we provide to these customers.

The on- and off-peak periods applicable to the business time of use energy charges (RT4 and RT16) are presented in Table 5.8.

Table 5.8: 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)

The structure of our three part time of use energy tariff is similar to our time of use energy tariffs, with an additional charging period defined during the day, i.e., the shoulder period.

We offer a single three part time of use energy tariff for business customers, available to business customers that only import energy from our network and to those that both import and export energy from our network. The structure of the tariff is the same for both types of business customers.

This reference tariff comprises:

- a fixed, daily charge for access to our network;
- a distinct variable energy charge that applies to each kWh of energy imported from our network during each of the on-peak, shoulder and off-peak periods; and
- a fixed, daily metering charge that reflects the metering reference service we provide to these customers.

The on-peak, shoulder and off-peak periods applicable to the business three part time of use energy tariff (RT18) are presented in Table 5.9.

Table 5.9: 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)

The structure of our three part time of use demand tariff is similar to our three part time of use energy tariff, with an additional tariff component that applies to the customer's maximum demand in a half-hour period during the on-peak period.

We offer a single three part time of use demand tariff for business customers, available to business customers that only import energy from our network and to those that both import and export energy from our network. The structure of the tariff is the same for both types of business customers.

This reference tariff comprises:

- a fixed, daily charge for access to our network;
- a variable demand based charge that applies to the maximum demand in a half-hour period within the on-peak period measured over a billing period (expressed in kW);[15]
- a distinct variable energy charge that applies to each kWh of energy imported from our network during each of the on-peak, shoulder and off-peak periods; and
- a fixed, daily metering charge that reflects the metering reference service we provide to these customers.

The on-peak, shoulder and off-peak periods applicable to the business three part time of use demand tariff (RT20) are presented in Table 5.10. We note that the same on-peak period applies to both the energy and demand components of this tariff.

Table 5.10: 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)

The structure of our multi part time of use energy tariff is similar to our three part time of use energy tariff, with an additional charging period defined during the day, i.e., the overnight period.

We offer a single multi part time of use energy tariff for business customers, available to business customers that only import energy from our network and to those that both import and export energy from our network. The structure of the tariff is the same for both types of business customers.

This reference tariff comprises:

- a fixed, daily charge for access to our network;
- a distinct variable energy charge that applies to each kWh of energy imported from our network during each of the on-peak, shoulder, off-peak and overnight periods; and
- a fixed, daily metering charge that reflects the metering reference service we provide to these customers.

[15] The demand charge is applied to each day of the billing period over which it is measured.

The on-peak, shoulder, off-peak and overnight periods applicable to the business multi part time of use energy tariff (RT22) are presented in Table 5.11.

Table 5.11: 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 Multi part time of use energy tariff with super off-peak period (RT35 and RT37)

The structure of our new multi part time of use energy tariff is similar to our existing/transitional multi part time of use energy tariff (RT22), with the 'overnight' period replaced with a 'super off-peak' period in the middle of the day and with different time definitions for the on-peak, shoulder and off-peak periods.

We offer a multi part time of use energy tariff with a super off peak period to business customers that only import energy from our network (RT35) and to those that both import and export energy from our network (RT37). The structure of the tariff is the same for both types of residential customers.

These reference tariffs comprise:

- a fixed, daily charge for access to our network;
- a distinct variable energy charge that applies to each kWh of energy imported from our network during each of the on-peak, shoulder, off-peak and super off-peak periods; and
- a fixed, daily metering charge that reflects the metering reference service we provide to these customers.

The on-peak, shoulder, off-peak and super off-peak periods applicable to the business multi part time of use energy tariff (RT35 and RT37) are presented in Table 5.12.

Table 5.12: Definition of charging windows for RT35 and 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

5.4 Distribution reference services – large business customers

5.4.1 High voltage metered demand tariff (RT5)

Our high voltage metered demand tariff is distinct from other business tariffs in that it does not include a variable charge that relates to energy usage, measured in kWh. Rather, our high voltage metered demand charge includes a variable charge that relates to the maximum half-hour demand of a customer measured over a rolling 12 month period, measured in kVA.[16] However, these variable demand charges are subject to

[16] Measuring demand in kVA, as distinct to kW, provides an incentive for customers to manage their power factor as close to unity as possible.

a discount that is calculate by reference to the energy usage of the customer across on- and off-peak periods.

This reference tariff comprises:

- a fixed, daily charge for access to our network that is based on the rolling 12 month maximum half-hour demand (expressed in kVA), which is eligible for an energy use related discount;
- a variable demand based charge that applies to the rolling 12 month maximum half-hour demand in excess of pre-determined demand thresholds (expressed in kVA), which is eligible for an energy use related discount;
- a variable charge applied to the electrical distance between the relevant connection point and the closest zone substation, which varies by the measured electrical distance and the rolling 12 month maximum half-hour demand;[17] and
- a fixed, daily metering charge that reflects the metering reference service we provide to these customers.

Our high voltage metered demand tariff contains two possible avenues to reduce the magnitude of the applicable charges, namely:

- reducing the rolling 12 month maximum half-hour demand in circumstances whereby a customer is able to reduce this value; and
- a discount on the fixed, daily access charge and variable demand based charge based on the proportion of total energy consumed during the off-peak period, capped at a maximum of 30 per cent.

The on-peak and off-peak periods applicable to the high voltage metered demand tariff (RT5) are presented in Table 5.13.

Table 5.13: Definition of charging windows for RT5

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

5.4.2 Low voltage metered demand tariff (RT6)

Our low voltage metered demand tariff is similar to our high voltage metered demand tariff (RT5). This tariff is eligible for low voltage connections only and contains larger charges to reflect the additional cost of using the low voltage network in addition to the high voltage network.

This reference tariff comprises:

- a fixed, daily charge for access to our network that is based on the rolling 12 month maximum half-hour demand (expressed in kVA),[18] which is eligible for an energy use related discount;
- a variable demand based charge that applies to the rolling 12 month maximum half-hour demand in excess of pre-determined demand thresholds (expressed in kVA), which is eligible for an energy use related discount;

[17] This charge is referred to as a 'demand length' charge. When a new distribution generator connects, this charge provides an incentive to choose a connection point as close as possible to the nearest zone substation.

[18] Measuring demand in kVA, as distinct to kW, provides an incentive for customers to manage their power factor as close to unity as possible.

- a variable charge applied to the electrical distance between the relevant connection point and the closest zone substation, which varies by the measured electrical distance and the rolling 12 month maximum half-hour demand;[19] and
- a fixed, daily metering charge that reflects the metering reference service we provide to these customers.

Our low voltage metered demand tariff contains two possible avenues to reduce the magnitude of the applicable charges, namely:

- reducing the rolling 12 month maximum half-hour demand in circumstances whereby a customer is able to reduce this value; and
- a discount on the fixed, daily access charge and variable demand based charge based on the proportion of total energy consumed during the off-peak period, capped at a maximum of 30 per cent.

The on-peak and off-peak periods applicable to the low voltage metered demand tariff (RT6) are presented in Table 5.14.

Table 5.14: Definition of charging windows 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

5.4.3 High voltage contract maximum demand tariff (RT7)

Our high voltage contract maximum demand tariff is distinct from other business tariffs in that the customer must nominate a contracted maximum demand (CMD) that reasonably reflects their expected annual peak demand. Consistent with that seen for transmission loads (TRT1), any demand utilised in excess of CMD will incur a penalty.

In addition, charges for this tariff are applied to demand measured in kVA, as distinct to kW. This provides an incentive for customers to manage their power factor as close to unity as possible.

This reference tariff comprises:

- a fixed, daily charge for access to our network, which is waived for customers with CMD greater than 7MVA;
- a variable demand based charge that applies to CMD in excess of pre-determined demand thresholds;
- a variable charge applied to the electrical distance between the relevant connection point and the closest zone substation, which varies by the measured electrical distance and CMD;
- a fixed, daily metering charge that reflects the metering reference service we provide to these customers;
- a fixed, daily administration charge; and
- ENUC calculated in accordance with our ENUC principles.

[19] This charge is referred to as a 'demand length' charge. When a new distribution generator connects, this charge provides an incentive to choose a connection point as close as possible to the nearest zone substation.

5.4.4 Low voltage contract maximum demand tariff (RT8)

Our low voltage contract maximum demand tariff is similar to our high voltage contract maximum demand tariff (RT7).

Consistent with our high voltage contract maximum demand tariff, this tariff requires customers to nominate a CMD, exceedance of which will result in penalty charges. Similarly, charges are applied per kVA to incentivise customers to manage their power factor as close to unity as possible.

This reference tariff comprises:

- a fixed, daily charge for access to our network, which is waived for customers with CMD greater than 7MVA;
- a variable demand based charge that applies to CMD in excess of pre-determined demand thresholds;
- a variable charge applied to the electrical distance between the relevant connection point and the closest zone substation, which varies by the measured electrical distance and CMD;
- a fixed, daily metering charge that reflects the metering reference service we provide to these customers;
- a fixed, daily administration charge; and
- ENUC calculated in accordance with our ENUC principles.

5.5 Distribution reference services – other

5.5.1 Streetlight tariff (RT9)

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

The streetlight tariff comprises:

- a fixed, daily charge for access to our network;
- a variable charge that applies to each kWh of energy imported from our network, which is based on the lamp wattage and illumination period for each asset; and
- a fixed asset charge based on the type of streetlight asset supplied.

5.5.2 Unmetered supplies tariff (RT10)

We provide 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 customer who connects with facilities and equipment deemed to be associated with streetlights will be placed on the streetlight tariff rather than this tariff.

The unmetered supplies tariff comprises:

- a fixed, daily charge for access to our network;
- a variable charge that applies to each kWh of energy imported from our network, which is calculated as the product of the nameplate rating of the connected equipment (expressed in kW) and the agreed hours of operation.

5.5.3 Distribution generator tariff (RT11)

The structure of our distribution generator tariff is similar to our 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 customers.

In general, the distribution generator tariff consists of:

- a fixed, daily charge for access to our network that reflects the costs of providing connection assets;
- a fixed, daily metering charge per meter;
- variable charges that apply to the DSOC of the individual customer that reflect their use of system and use of control system services;[20]
- a variable charge applied to the electrical distance between the relevant connection point and the closest zone substation, which varies by the measured electrical distance, the DSOC of the individual customer and the voltage level at which the connection is located; and
- ENUC calculated in accordance with our ENUC principles.

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 and RT24 consist of:

- the reference tariff applicable to the reference service upon which the connecting customer is provided; less
- a discount that applies to the connection point as set out below.

Western Power will provide a discount to the applicable reference tariff 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.

[20] The control system services variable charge for distribution generators is applied to their nameplate capacity, rather than their DSOC.

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 Low voltage distribution storage service tariff (RT38)

We are introducing a new tariff for storage systems connected to the low voltage distribution network in AA5. The structure of our new low voltage distribution storage service tariff is identical to our new multi part time of use energy tariff (with a super off-peak period) for bi-directional services (RT37).

This reference tariff comprises:

- a fixed, daily charge for access to our network;
- a distinct variable energy charge that applies to each kWh of energy imported from our network during each of the on-peak, shoulder, off-peak and super off-peak periods; and
- a fixed, daily metering charge that reflects the metering reference service we provide to these customers.

Consistent with our approach for bi-directional distribution connected-customers, we will not charge low voltage distribution storage systems for exporting energy into the grid. This reflects that we want to encourage the uptake of storage systems and our preference for a customer-led, demand-side solution to address the costs that may arise from customer exports, as discussed in section 3.1 of our TSS Overview. Further, the costs imposed by customer exports, at present, are not significant in the context of our total efficient costs.

The low voltage distribution storage service tariff provides an incentive for storage systems to shift their load into the super off-peak period.

The on-peak, shoulder, off-peak and super off-peak periods applicable to the low voltage distribution storage service tariff are presented in Table 5.15.

Table 5.15: Definition of charging windows for RT38

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

5.5.6 High voltage distribution storage service tariff (RT39)

We are introducing a new tariff for high voltage distribution network connected storage systems in AA5.

The high voltage distribution storage service tariff has the same structure as the high voltage metered demand tariff (RT5), which is offered to large business connections on the high voltage network. Consistent with all other tariffs for high voltage connections, charges for this tariff are applied to demand measured in kVA, as distinct to kW. This provides an incentive for storage devices to manage their power factor as close to unity as possible.

This reference tariff comprises:

- a fixed, daily charge for access to our network that is based on the rolling 12 month maximum half-hour demand (expressed in kVA), which is eligible for an energy use related discount;

- a variable demand based charge that applies to the rolling 12 month maximum half-hour demand in excess of pre-determined demand thresholds (expressed in kVA), which is eligible for an energy use related discount;
- a variable charge applied to the electrical distance between the relevant connection point and the closest zone substation, which varies by the measured electrical distance and the rolling 12 month maximum half-hour demand;[21] and
- a fixed, daily metering charge that reflects the metering reference service we provide to these customers.

Consistent with our approach for bi-directional distribution connected-customers, we will not charge high voltage distribution storage systems for exporting energy into the grid. This reflects that we want to encourage the uptake of storage systems and our preference for a customer-led, demand-side solution to address the costs that may arise from customer exports, as discussed in section 3.1 of our TSS Overview.

Our high voltage distribution storage service tariff contains two possible avenues to reduce a customer's network bill, namely:

- reducing the rolling 12 month maximum half-hour demand in circumstances whereby a customer is able to reduce this value; and
- a discount on the fixed, daily access charge and variable demand based charge based on the proportion of total energy consumed during the off-peak period, capped at a maximum of 30 per cent.

The on-peak and off-peak periods applicable to the high voltage distribution storage service tariff is presented in Table 5.16.

Table 5.16: Definition of charging windows for RT39

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

5.5.7 Electric vehicle charging service tariffs (RT40 and RT41)

We are introducing a new tariff for dedicated EV charging stations in AA5. The structure of our new EV charging service tariffs is identical to our existing metered demand tariffs (RT5 and RT6). Consistent these metered demand tariffs, charges for this tariff are applied to demand measured in kVA, as distinct to kW. This provides an incentive for storage devices to manage their power factor as close to unity as possible.

We offer two dedicated EV charging service tariffs, one for EV charging stations connected to the low voltage distribution network (RT40) and another for EV charging stations connected to the high voltage distribution network (RT41).

These two reference tariffs have the same structure and comprise:

- a fixed, daily charge for access to our network that is based on the rolling 12 month maximum half-hour demand (expressed in kVA), which is eligible for an energy use related discount;

[21] This charge is referred to as a 'demand length' charge. When a new distribution generator connects, this charge provides an incentive to choose a connection point as close as possible to the nearest zone substation.

- a variable demand based charge that applies to the rolling 12 month maximum half-hour demand in excess of pre-determined demand thresholds (expressed in kVA), which is eligible for an energy use related discount;
- a variable charge applied to the electrical distance between the relevant connection point and the closest zone substation, which varies by the measured electrical distance and the rolling 12 month maximum half-hour demand;[22] and
- a fixed, daily metering charge that reflects the metering reference service we provide to these customers.

Our electric vehicle charging service tariffs contain two possible avenues to reduce the magnitude of the applicable charges, namely:

- reducing the rolling 12 month maximum half-hour demand in circumstances whereby a customer is able to reduce this value; and
- a discount on the fixed, daily access charge and variable demand based charge based on the proportion of total energy consumed during the off-peak period, capped at a maximum of 30 per cent.

The on-peak and off-peak periods applicable to the electric vehicle charging service tariffs (RT40 and RT41) are presented in Table 5.17.

Table 5.17: Definition of charging windows for RT40 and RT41

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

5.5.8 Other charging components (RT25 to RT30)

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; and
- 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.

Consistent with our historical approach, we set prices for supply abolishment (RT25), remote load / inverter control (RT26), remote de-energise (RT28) and remote re-energise (RT29) services 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.

[22] This charge is referred to as a 'demand length' charge. When a new distribution generator connects, this charge provides an incentive to choose a connection point as close as possible to the nearest zone substation.

6. 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 limitation as detailed in chapter 7. (Thus, the nominated TUOS price will converge over time with and future price based on future T-Price runs.)
4. The TUOS price will be published once the connection point is commissioned.
5. Where another user subsequently connects to such a connection point the price that will apply will be the price applying to that connection point at the time.
6. The common service, metering and control system prices that apply in this circumstance will be the standard published prices.

Policy Statement – Transmission Connection Price

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

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

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

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

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

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

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

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

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

7. Method for estimating the weighted average price change for each reference tariff

Clause 7.1D of the Code requires the TSS to:

> *…be accompanied by a reference tariff change forecast which sets out, for each reference tariff, the service provider's forecast of the weighted average annual price change for that reference tariff for each pricing year of the access arrangement period.*

In this section we describe our methodology for estimating an average price change forecast for each reference tariff. The results of this forecast are presented in section 5 of the TSS Overview.

Consistent with the cost allocation process described in section 3, each reference service is allocated a portion of total costs that reflects the efficient costs of serving the customers using that reference service.

This more prescriptive cost allocation process is being applied for the first time during this access arrangement period. We acknowledge that the current level of costs recovered from each reference tariff may be quite different from the efficient costs allocated by our new methodology. As such, we intend to transition the revenue recovered from each reference tariff towards their efficient level over the course of this access arrangement period.

The method for estimating the weighted average price change proceeds as follows:

- step 1 – determine the efficient cost per customer in a base year;
- step 2 – use the efficient cost per customer from the base year to determine the efficient cost per customer for all years of the access arrangement; and
- step 3 – iteratively determine the yearly change in price for each reference tariff that moves the cost per customer towards the efficient level.

Each of these steps are explained in turn below.

7.1 Step 1 – efficient cost per customer in the base year

The first step in this process is to select the year from which to base the calculation of efficient costs per customer. We have chosen the base year to be the same year for which the cost allocation methodology is performed.

From the cost allocation process in this base year we obtain the following:

- the efficient share of total costs, both distribution and transmission, per customer group;
- the efficient share of total costs, both distribution and transmission, allocated to reference tariffs within each customer group; and
- the underlying customer numbers which form the basis for this cost allocation.

To obtain the efficient cost in the base year for a particular reference tariff we take the efficient share of total costs for that reference tariff, within the relevant customer group and multiply this proportion by the total revenue requirement, both distribution and transmission. The efficient cost per customer is then obtained by dividing this efficient cost by the customer numbers for each reference tariff in the base year.

7.2 Step 2 – efficient cost per customer in all years of the access arrangement

The second step in this process is to repeat step 1 for each year in the access arrangement while holding the relative cost shares and the customer numbers constant from the base year. This process effectively shifts the efficient cost per customer in the base year from step 1 by the changes in the revenue requirement for each year in the access arrangement.

This provides an indicative measure for the efficient cost per customer that Western Power should try to achieve for each year in the access arrangement. This indicative measure ensures consistency in all years as it is based upon the same underlying cost allocation methodology and controls for the impact of changes in quantity on prices by using the same distribution of customers each year. However, this measure varies each year with changes in total revenue and so is reflective of the impact of changing costs on prices.

7.3 Step 3 – determine the yearly transition of cost per customer

Each year, Western Power allocates costs to be recovered from each reference tariff that reflects some change in average price per customer from the previous year.

In this step, we take the average cost per customer from the previous year and compare this to the efficient cost per customer for the current year to determine the change in cost per customer required to attain this efficient level. The process identifies which reference tariffs should experience an increase in cost per customer to transition towards the efficient level and vice versa.

The pivotal component to this step is the establishment of a cap on the speed of transition towards the efficient level. By way of example, we may calculate that a five per cent increase in cost per customer is required to attain the efficient level however feedback from customers and end users may indicate that customers have a strong preference to keep price increases below two per cent per year. In this case we would increase the cost per customer for this reference tariff by two per cent only.

In order to facilitate this two per cent increase, there must be some offsetting decreases in the costs per customer for other reference tariffs. In fact, by definition if there are certain reference tariffs that are priced too high then there must other reference tariffs that are priced too low. The setting of a price cap on the speed of transition for increases in average cost per customer allows for the calculation of a necessary offsetting decrease for those reference tariffs that need to decrease towards their efficient level. This necessary offsetting decrease is set to recover total revenue for the particular year given the forecast of customer numbers in that year.

Ultimately, the yearly change in cost per customer for each reference tariff is determined as:

- the lesser of the transition cap on increases or the requisite efficient change for reference tariffs that need an increase in cost per customer; or
- the lesser, in magnitude, of the offsetting necessary decrease or the requisite efficient change for reference tariffs that need an increase in cost per customer.

8. Compliance checklist

This section includes a checklist for the key requirements in the Code relating to the TSS and how they are addressed.

Table 8.1: Compliance checklist

Clause	Requirement	Relevant sections
Tariff structure statements		
7.1A	A tariff structure statement of a service provider of a covered network must set out the service provider's pricing methods, and must include the following elements: a) the structures for each proposed reference tariff; b) the charging parameters for each proposed reference tariff; and c) a description of the approach that the service provider will take in setting each reference tariff in each price list of the service provider during the relevant access arrangement period in accordance with sections 7.2 to 7.12.	***(a) and (b)*** TSS Overview, section 3 Technical Summary, section 5 ***(c)*** TSS Overview, section 4
7.1B	A tariff structure statement must comply with: a) the pricing principles; and b) any applicable framework and approach.	This compliance checklist
7.1D	A tariff structure statement must be accompanied by a reference tariff change forecast which sets out, for each reference tariff, the service provider's forecast of the weighted average annual price change for that reference tariff for each pricing year of the access arrangement period.	TSS Overview, section 5 Technical Summary, section 7
Pricing objective		
7.3	Subject to sections 7.7 and 7.12, the pricing methods in a tariff structure statement must have the objective (the "pricing objective") that the reference tariffs that a service provider charges in respect of its provision of reference services should reflect the service provider's efficient costs of providing those reference services.	TSS Overview, 4.2
Application of pricing principles		
7.3B	A service provider's reference tariffs may not vary from the reference tariffs that would result from complying with the pricing principles set out in sections 7.3D to 7.3H, except to the extent necessary to give effect to the pricing principles set out in sections 7.3I to 7.3J.	***Customer preferences (7.3I)*** TSS Overview, section 2.4 ***Transition considerations*** TSS Overview, section 4 and section 5
Pricing principles		

Clause	Requirement	Relevant sections
7.3D	For each reference tariff, the revenue expected to be recovered must lie on or between: a) an upper bound representing the stand-alone cost of service provision for customers to whom or in respect of whom that reference tariff applies; and b) a lower bound representing the avoidable cost of not serving the customers to whom or in respect of whom that reference tariff applies.	Technical summary, section 4
7.3E	The charges paid by, or in respect of, different customers of a reference service may differ only to the extent necessary to reflect differences in the average cost of service provision to the customers.	TSS Overview, section 4 Technical Summary, section 3
7.3F	The structure of reference tariffs must, so far as is consistent with the Code objective, accommodate the reasonable requirements of users collectively and end-use customers collectively.	TSS Overview, section 2.4 Technical Summary, section 5
7.3G	Each reference tariff must be based on the forward-looking efficient costs of providing the reference service to which it relates to the customers currently on that reference tariff with the method of calculating such cost and the manner in which that method is applied to be determined having regard to: a) the additional costs likely to be associated with meeting demand from end-use customers that are currently on that reference tariff at times of greatest utilisation of the relevant part of the service provider's network; and b) the location of end-use customers that are currently on that reference tariff and the extent to which costs vary between different locations in the service provider's network.	TSS Overview, section 4 Technical Summary, section 2
7.3H	The revenue expected to be recovered from each reference tariff must: a) reflect the service provider's total efficient costs of serving the customers that are currently on that reference tariff; b) when summed with the revenue expected to be received from all other reference tariffs, permit the service provider to recover the expected revenue for the reference services in accordance with the service provider's access arrangement; and c) comply with sections 7.3H(a) and 7.3H(b) in a way that minimises distortions to the price signals for efficient usage that would result from reference tariffs that comply with the pricing principle set out in section 7.3G.	TSS, section 4 Technical summary, section 3
7.3I	The structure of each reference tariff must be reasonably capable of being understood by customers that are currently on that reference tariff, including enabling a customer to predict the likely annual changes in reference tariffs during the access arrangement period, having regard to: a) the type and nature of those customers; b) the information provided to, and the consultation undertaken with, those customers.	Technical summary, section 5 TSS Overview, section 5
7.3J	A reference tariff must comply with this Code and all relevant written laws and statutory instruments.	Noted.