Appendix F.2

Tariff Structure Statement Technical summary

Revised proposed access arrangement

15 November 2022

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

EDM 58784775

Tariff Structure Statement Technical summary

To apply from 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

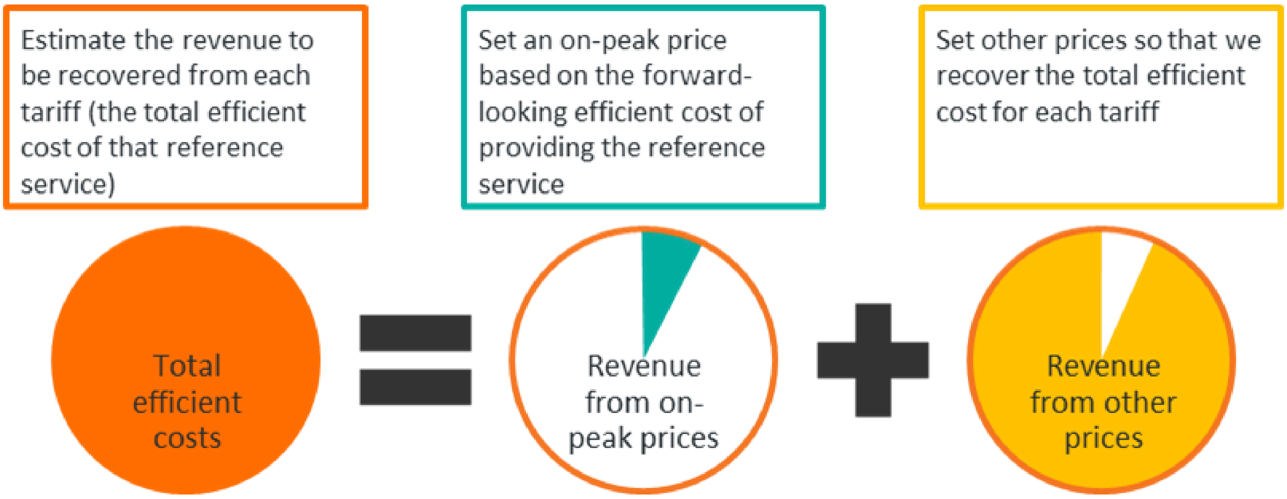
Recent changes to the *Electricity Networks Access Code 2004* (**Code**) require Western Power to apply a new framework for tariffs. The Code specifies a pricing objective that Western Power's reference tariffs:[1]

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

We achieve this objective through the use of the range of pricing principles presented in the Code,[2] which reflect widely accepted economic principles, and the 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 Economic Regulation Authority (**ERA**), across our reference services, while ensuring that the efficient costs allocated to each

[1] Electricity Networks Access Code, clause 7.3.
[2] Electricity Networks Access Code, clause 7.3A-J.

tariff falls between the stand-alone and avoidable cost of providing that service.[3] This approach is explained in further detail in this TSS technical summary.

The requirement in the Code to prepare a TSS relates to distribution reference tariffs.[4] However, we also include a description of the structure of transmission reference tariffs and our approach to setting those tariffs in sections 6 and 7, 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 2	Forward-looking efficient cost	Describes how we estimate long run marginal cost and convert our estimates into an efficient price signal.
Section 3	Efficient cost target	Explains how we estimate the efficient target that guides the allocation of our revenue target to each reference tariff.
Section 4	Allocation of target revenue	Explains how we allocate our target revenue (or efficient costs) to each reference tariff.
Section 5	Stand-alone and avoidable cost	Describes how we estimate the upper and lower bound of revenue to be recovered from each reference tariff.
Section 6	Tariff structures	Presents a detailed description of the structure of each reference tariff.
Section 7	Price setting for new transmission reference tariffs	Describes how we the estimate the efficient target that guides the allocation of our target revenue to transmission reference tariffs and summarises the price setting policy for new transmission nodes.
Section 8	Reference tariff change forecast	Presents our methodology for calculating the weighted average annual price change for each reference tariff over the AA5 period.
Section 9	Compliance checklist	Confirms our compliance with the requirements in the Code relating to the TSS.

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

[3] Electricity Networks Access Code, clause 7.3D.
[4] 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:[5]

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 end-users 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 end-users the additional network costs caused by further use of the network during the on-peak period. The efficient outcomes may then include:

- an end-user shifting their load outside of the on-peak period, which results in a cost saving for them and all other end-users;
- an end-user 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
- an end-user that values their use of 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 end-users.

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 end-users over the medium to long term, as well as in managing any bill impacts during the transition to more efficient pricing.

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

[5] The Code, clause 7.3G.

2.2 Consideration of how long run marginal cost varies across the network

The LRMC of providing our 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 end-users using less than 1MVA of electricity. This also reflects the requirement in the Code that:[6]

> *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 end-users currently on that reference tariff.

For similar end-users, 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 end-users 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 end-users 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 voltage to which an end-user is connected. By way of example:

- further use of the network by an end-user 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 an end-user 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 voltage to which those end-users connect, i.e., high voltage and low voltage. We also estimate LRMC for residential and business end-users separately at the low voltage level.

This reflects that further use of the network by residential end-users (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).

[6] 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	
RT35	RT20	
RT37	RT22	
	RT34	
	RT36	
	RT38	
	RT40	

2.4 Estimation methodology

There are two commonly considered economic 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;[7]
- 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 end-users; and
- calculating the present value of future growth-related expenditure caused by that group of end-users.

We calculate the net present value of demand growth by:

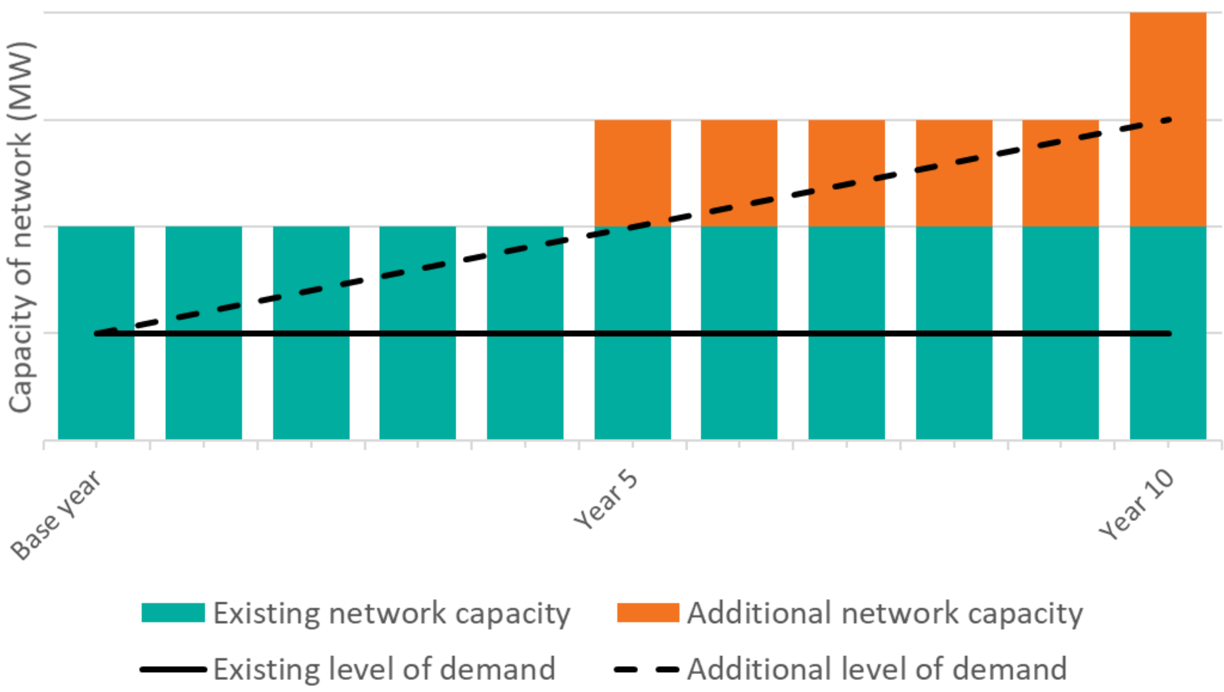
- evaluating the additional demand met by Western Power's network over the ten-year period;
- estimating the cumulative increase of demand for each group of end-users; and
- calculating the present value of additional demand caused by that group of end-users.

We calculate the LRMC for each group of end-users 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 weighted average cost of capital (**WACC**).

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



[7] 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.

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 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 end-users 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 end-users 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 reference tariffs.

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. Efficient cost target for distribution reference services

In this section we explain how we estimate the efficient cost of providing each distribution reference service,[8] which we refer to as the efficient cost target for a distribution reference service.

In section 4 we then explain how we allocate our target revenue to each reference tariff, and set prices, so that the revenue recovered from each tariff transitions towards that strictly efficient reference point, while managing bill impacts.

Although economic principles establish an upper and lower bound on the total efficient cost for the provision of network services – being the stand-alone and avoidable costs[9] – there is no economic principle that identifies a unique, efficient level of costs.

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 and recovery of costs in the previous year,[10] whereas Ausgrid (a network service provider in New South Wales) approved approach is:[11]

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

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

We consider this approach to be a fair and reasonable basis for estimating the efficient cost of providing each reference service.

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

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

Table 3.1 indicates how our total efficient network costs are allocated between distribution and transmission reference services and the role played by the methodology by which we estimate the efficient contribution.

[8] The corresponding explanation for transmission reference services is contained in section 7.1.

[9] See section 5 for a detailed explanation of stand-alone and avoidable costs.

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

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

Table 3.1: Efficient disaggregation of distribution and transmission costs to reference services

	Distribution reference services	Transmission reference services
Distribution costs	Determined by the efficient cost estimation methodology for distribution reference services.	Not relevant
Transmission costs	The transmission costs that are not allocated to transmission connections by the efficient cost estimation methodology for transmission reference services (section 7.1) are recovered from distribution reference services. These costs are shared across distribution connections as determined by the efficient cost estimation methodology for distribution reference services.	Determined by the efficient cost estimation methodology for transmission reference services (section 7.1).

The process by which we estimate the efficient cost target, ie, the efficient cost estimation methodology, for distribution reference services is explained below.

3.1 Contribution of total network costs to distribution reference tariffs

Clause 7.3 of the Code presents a pricing objective:[12]

> *…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 end-users and the extent to which they use those assets and services, relative to end-users using other reference services.

The total efficient cost for each reference service, or the efficient cost target, is the efficient reference point towards which we transition the revenue recovered from our reference tariffs, consistent with the pricing objective of the Code, while managing bill impacts.

This process by which we estimate the efficient cost target for our distribution reference services is summarised in Figure 3.1.

[12] The Code, clause 7.3.

Figure 3.1: Efficient cost target estimation methodology for distribution reference services

1. Estimate the value of distribution asset types and cost pools across distinct geographic zones
2. Estimate the extent to which each reference service uses each type of asset in each geographic zone
3. Assign the distribution revenue target to each reference service based on the relative value of the assets and cost pools that reference service uses across the entire network

Fundamental to our methodology is the segmenting of Western Power's distribution network by reference to:

- six distribution asset types and 'cost pools',[13] relating to function and voltage level; and
- five geographic zones.

We describe our cost pools and geographic zones in section 3.1.1. In the sections that follow we describe each of the three steps illustrated in Figure 3.1 above.

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.

Distribution asset types and cost pools

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

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

[13] 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.

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

The five geographic zones defined for the distribution system are:

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

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

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

Asset valuation

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.[14]

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.

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

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 had very little effect 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 relative share of our total network value by asset type (excluding streetlight, metering, and admin assets) and geographic location.

Table 3.2: Relative value of assets by asset type (excluding streetlight, metering, and admin assets) and geographic zone

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

Streetlight, metering, and admin

Streetlight, metering, and admin assets are not included in the asset types listed in Table 3.2. Their share of our efficient cost is calculated separately and then the relative shares in Table 3.2 are adjusted downwards such that, when all asset types are combined, their relative shares sum to 100 per cent. The result of this process is presented in the next section in Table 3.4, which includes all asset types.

The total efficient costs of providing streetlight, metering and admin services are based on the share of the distribution revenue target that is directly attributable to each of these cost pools. That is, the cost allocation for streetlight, metering and admin services is not defined by determining the value of the types of assets in particular locations and then assigning a share of these costs to the streetlight and metering reference services relative to their use of those assets, as described in Table 3.2.

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

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

The total efficient costs, or annual revenue requirement, of providing streetlight, metering and admin services is presented in Table 3.3.

Table 3.3: Streetlight, metering and admin cost of service ($m Real as at 30 June 2022)

Cost pool	2023	2024	2025	2026	2027
Streetlight services					
Annual revenue requirement	*$33*	*$35*	*$36*	*$39*	*$41*
Portion of distribution annual revenue requirement	*2%*	*2%*	*2%*	*3%*	*3%*
Metering services					
Annual revenue requirement	*$54*	*$61*	*$68*	*$76*	*$83*
Portion of distribution annual revenue requirement	*3%*	*4%*	*4%*	*5%*	*6%*
Non-network related expenditure (admin services)					
Annual revenue requirement	*$161*	*$172*	*$188*	*$203*	*$215*
Portion of distribution annual revenue requirement	*10%*	*11%*	*12%*	*13%*	*15%*

The annual revenue requirement for streetlight, metering and admin services is not disaggregated by geographic zone in the building block approach. We distribute these cost pools among geographic zones using the relative allocation of the total value of our assets across these zones, as presented in Table 3.2.

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

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

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

We present the relative share of our total annual revenue requirement by asset type and cost pool over each year in AA5, and in total, in Table 3.4.

Table 3.4: Relative contribution of Western Power's annual revenue requirement by asset type and cost pool

Asset type/cost pool	2023	2024	2025	2026	2027	AA5 total
High voltage	*48%*	*48%*	*47%*	*46%*	*46%*	***47%***
Low voltage	*31%*	*31%*	*30%*	*30%*	*29%*	***30%***
Transformers	*5%*	*5%*	*5%*	*5%*	*5%*	***5%***
Metering	*3%*	*4%*	*4%*	*4%*	*5%*	***4%***
Streetlights	*2%*	*2%*	*2%*	*2%*	*2%*	***2%***
Admin	*10%*	*10%*	*11%*	*12%*	*13%*	***11%***

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

By way of illustration, the 48 per cent share for high voltage assets in 2023 in Table 3.4 reflects the share for high voltage assets in Table 3.2 (57.3 per cent), adjusted down by 15 per cent in relative terms (ie, 57.3 per cent multiplied by 0.85) to account for the fact that streetlight, metering and admin assets are not included in Table 3.2, but are estimated to account for 15 per cent of efficient costs in 2023, as per Table 3.3.

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 end-users using each reference service in each geographic zone.

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

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

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

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

- contribution of end-users using each reference service to system-wide maximum demand, which incorporates the diversity in maximum demand for different types of reference services;[15]
- contribution of end-users using each reference service to total energy consumption; and
- total number of connections for each reference service.

We allow for the relative use of each distribution asset type and cost pool by end-users using each reference service to be determined differently for different types of assets and different types of reference services. By way of example, the relative use of the administrative service cost pool is determined by the total number of connections for each reference service whereas the relative use of network assets, such as transformers and the high or low voltage networks, uses the contribution to system-wide maximum demand. This ensures that costs with different characteristics are allocated in a manner that best suits these characteristics.

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

- the contribution to system-wide maximum demand for transformers and high voltage distribution network assets;

[15] 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.

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

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

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

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

The relative contribution towards the use of the network for each of our customer classes,[16] from the 2021-22 financial year, is presented in Table 3.5.

Table 3.5: Relative contribution to total network usage – 2021-22 financial year

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

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

By using actual use of system estimates that reflect the conditions at the time of the cost allocation calculation, the allocation of total efficient costs to each distribution reference service will capture the changing behaviour of different types of end-users. For instance, load shifting of residential end-users away from the traditional demand peak in the evening through use of distributed energy resources (**DER**) would result in a lower contribution to system maximum demand for these end-users. As a result, the allocation of costs to these end-users will decline to reflect their reduced contribution to the incursion of costs.

This relative use of system allocation between our customer classes is used in conjunction with the disaggregation of our annual revenue requirement from step 1 (as shown in Table 3.4) to disaggregate our total efficient costs to an efficient target revenue for each customer class. We note that both of these

[16] We previously disaggregated all distribution connected end-users into ten 'customer groups'. For AA5, we have refined this categorisation so that al distribution connected end-users are classified into seven 'customer classes'.

processes incorporate the geographic dimension of our network to the efficient target revenue to end-users.

The combination of step 1 and step 2 is presented in Table 3.6, which shows the relative contribution of total target revenue over the entirety of AA5 by asset type and cost pools for all customer classes.

Table 3.6: Relative allocation of total efficient costs for AA5 across customer classes and cost pools

Cost pool	Residential	LV business - small	Industrial	Streetlights	Unmetered	Generators	Share of total AA5 revenue
High voltage asset costs	*20%*	*12%*	*15%*	*0%*	*0%*	*0%*	***47%***
Low voltage asset costs	*13%*	*7%*	*11%*	*0%*	*0%*	*0%*	***30%***
Transformer asset costs	*2%*	*1%*	*2%*	*0%*	*0%*	*0%*	***5%***
Metering cost of service	*3%*	*0%*	*0%*	*1%*	*0%*	*0%*	***4%***
Streetlight cost of service	*0%*	*0%*	*0%*	*2%*	*0%*	*0%*	***2%***
Admin cost of service	*8%*	*1%*	*0%*	*2%*	*0%*	*0%*	***11%***
Share of total efficient costs	***46%***	***21%***	***27%***	***5%***	***0%***	***0%***	***100%***

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

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

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

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

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

- annual total distribution target revenue is determined, as approved by the ERA;

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

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

3.1.4 Transmission revenue recovered from distribution end-users

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

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

In a similar manner to how distribution network asset values are allocated across geographic zones in step 1, the pass through of transmission service revenue can be aggregated from the zone substation level to the geographic zone level. Table 3.7 presents an indicative breakdown of transmission service revenue by geographic zone.

Table 3.7: Relative value of transmission service revenue to be recovered from distribution end-users

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

The disaggregation of the pass through of transmission service revenue among customer classes is consistent with the disaggregation of total distribution revenue to customer classes. That is, while distribution revenue is assigned to cost pools that are disaggregated by different measures of the relative use of the network, the combination of all cost pools gives rise to a relative share of total distribution revenue for each customer class (see the bottom row of Table 3.8).

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

3.1.5 Resulting efficient cost target estimation

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

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

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

We present the main determinants of our efficient cost target across customer classes and different network cost pools in Table 3.8.

Table 3.8: Efficient cost target for AA5 across customer classes and cost pools ($m)

	Share of total AA5 revenue (as per Table 3.7)	Allocation to customer class	Residential	LV business - small	Industrial	Streetlights	Unmetered	Generators	Grid-connected batteries
High voltage asset costs	47% of distribution revenue	Contribution to maximum demand	*$1,303*	*$804*	*$973*	*$0*	*$3*	*$0*	*$0*
Low voltage asset costs	30% of distribution revenue	Even split between contribution to maximum demand and total energy consumption	*$828*	*$431*	*$710*	*$11*	*$3*	*$0*	*$0*
Transformer asset costs	5% of distribution revenue	Contribution to maximum demand	*$134*	*$83*	*$100*	*$0*	*$0*	*$0*	*$0*
Metering cost of service	4% of distribution revenue	Share of total number of connections	*$194*	*$17*	*$1*	*$51*	*$3*	*$0*	*$0*
Streetlight cost of service	2% of distribution revenue	To streetlight connections only	*$0*	*$0*	*$0*	*$143*	*$0*	*$0*	*$0*
Admin cost of service	11% of distribution revenue	Share of total number of connections	*$534*	*$46*	*$3*	*$140*	*$8*	*$0*	*$0*
Transmission revenue pass-through	All transmission revenue not recovered from transmission reference services	Assigned in the same proportion of total distribution revenue across customer classes	*$791*	*$488*	*$591*	*$0*	*$2*	*$0*	*$0*

Total revenue recovered from distribution connections over AA5			***$3,783***	***$1,869***	***$2,378***	***$345***	***$19***	***$0***	***$0***

4. Allocation of target revenue to reference tariffs

In the previous section we describe how we estimate the efficient cost of providing each reference service.

In this section we describe how we allocate our target revenue to each reference tariff and set prices so that the level of revenue we expect to recover from each tariff:

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

We also explain how we set the prices that comprise each reference tariff so that we expect to recover the revenue allocated to each tariff, while avoiding unacceptable bill impacts.

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

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

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

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

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

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

4.1 Three step allocation

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

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

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

We note that the requirement for our reference tariffs to reflect the efficient costs of providing those reference service is a new addition to the Code. A consequence of this is that the baseline adjustment revenue allocations may differ substantially from the efficient allocation in each year, meaning significant price changes would be required to transition each customer class directly to its efficient allocation. When an increase in the revenue allocation is required for a customer class to transition to its efficient allocation, to manage bill impacts, we endeavour to limit the increase in revenue per end-user to two per cent on top of the baseline adjustment.

Due to the delay in the commencement of AA5, prices in the first year (FY23) were held constant, ie, they were left unchanged from the final year of AA4. This meant that the revenue implied by our prices and forecast number of connections and volumes in the first year of AA5 (FY23) did not reconcile with our target revenue in that year.

This created significant challenges for the application of our cost methodology in the second year of AA5 (FY24), since it has a strong intertemporal dimension, ie, it is linked from year-to-year. The second year of AA5 (FY24) could therefore be characterised as a transitional year for our cost allocation methodology, since its focus was predominantly on managing bill impacts, rather than on transitioning to more efficient cost allocations using our three-step methodology, while also managing bill impacts.

We explain our three-stage revenue allocation methodology in further detail below.

4.2 Step 1: Baseline adjustment

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

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

We refer to this adjustment as the 'baseline adjustment', ie, it is a baseline, average change in price that will allow us to recover our ERA-approved revenue target, without any consideration given to improving the efficiency of our cost allocation.

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

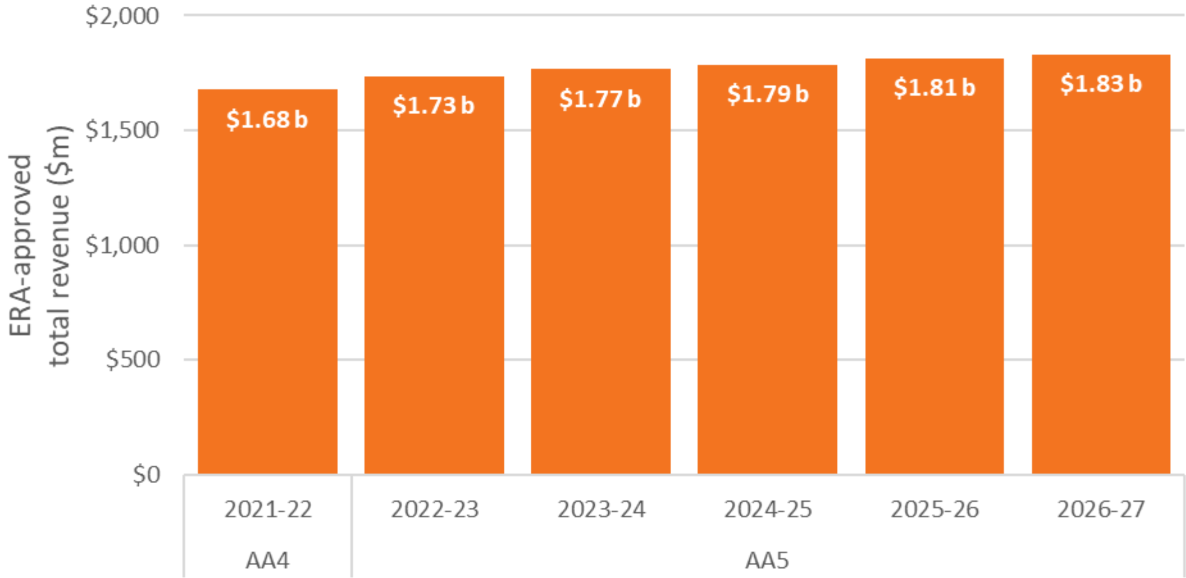
In Table 4.1 we present the forecast number of connections in each customer class over AA5, which shows that the number of connections is growing across nearly all customer classes.

Table 4.1: Forecast distribution connection numbers by customer class over AA5

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

In figure 4.1 we present our forecast approved revenue, which gradually increases over AA5.

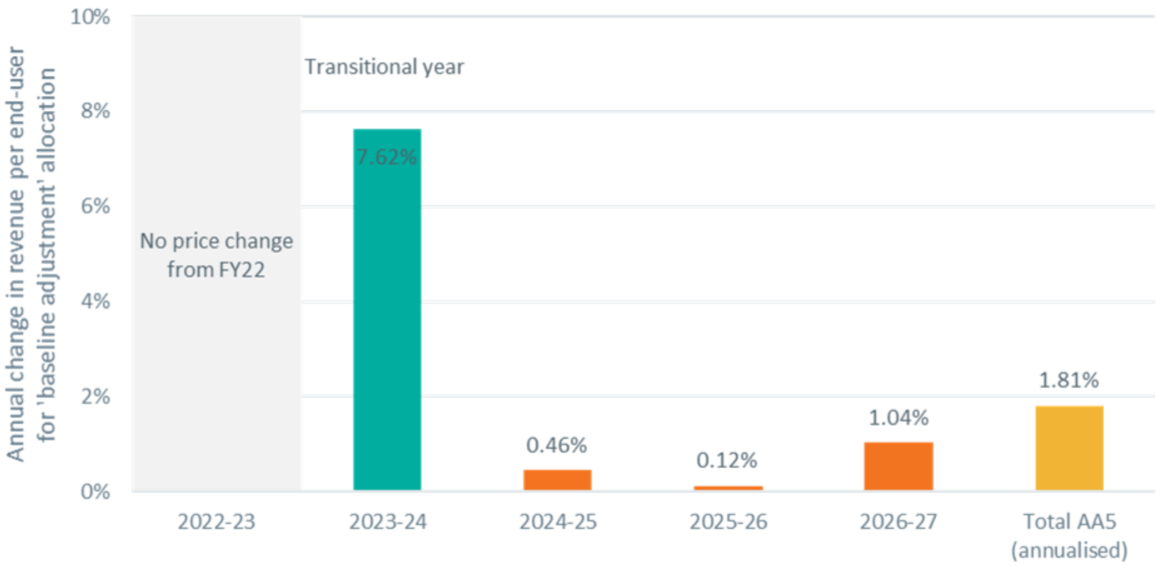
Figure 4.1: Forecast path of Western Power's total revenue over AA5 period



Our expected growth in the number of connections partially, but not fully, offsets the effects of increasing approved revenue over AA5.

In Figure 4.2 we show that the average annualised change in revenue per end-user is 1.8 per cent per annum over AA5, in nominal terms. However, as noted above, holding prices constant in the first year of AA5 (FY23) requires a transitional year of price changes in FY24 to make up for foregone revenue, while managing and smoothing bill impacts over AA5. Without this transitional approach in FY24, some end-users would experience strong volatility in price changes over AA5, ie, sharp increase and then sharp decreases in bills.

Figure 4.2: Forecast change in revenue per end-user for all end-users over AA5 (before improvements in efficiency)



It follows that the outcome of this first step in our cost allocation methodology is a baseline, average change in price that will allow Western Power to recover its approved revenue target, without any consideration given to improving the efficiency of our cost recovery (for example, actual demand being greater than forecast demand in a year).

In other words, the application of this change in average revenue per end-user would hold constant the relative efficiency of our cost allocation from the previous year.

4.3 Step 2: Transitioning to a more efficient allocation

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

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

In Table 4.2 we illustrate the direction in which the revenue recovered from each customer class needs to shift over AA5 to move closer to the efficient cost target that we describe in section 3, after the baseline adjustment.

Table 4.2: Direction of required transition towards efficient cost allocation over AA5

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

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

There are strong interrelationships between the transitional decisions for each customer class, ie, a decrease in the revenue allocation for a customer class from which we recover a lot of revenue (eg, residential end-users), can require larger increase in revenue allocation for smaller customer classes to ensure that we still expect to recover our approved revenue target in aggregate.

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

In Table 4.3 we present the change in revenue per end-user for each customer class in FY25 to FY27 as a result of the baseline adjustment in step one and transitional adjustment to improve efficiency in step two.[17]

[17] We explain in section 4.1 that holding prices constant in the first year of AA5 (FY23) necessitated a transitional year in the second year of AA5 (FY24).

Table 4.3: Annualised change in revenue per end-user over AA5

Customer class	Baseline adjustment (annualised)	Direction of incremental efficiency adjustment in step two
Residential	1.81%	Decrease
LV business – small	1.81%	Increase
Industrial	1.81%	Increase
Streetlights	1.81%	Increase
Unmetered	1.81%	Increase
Generators	1.81%	Decrease

Having allocated target revenue to each customer class, we then allocate target revenue to the individual reference tariffs that comprise each customer class. Since each customer class comprises end-users that impose similar costs on our network, we allocate revenue to each reference tariff to ensure that we recover a similar level of revenue from end-users that impose similar costs on our network.

This reflects that Western Power does not have control over the assignment of end-users to reference services and reference tariffs, and that retailers/customers can choose the reference tariff that minimises their network bill. It is inefficient and inequitable for certain end-users to reduce their network bill simply by changing tariff, while making no change in their use of the network – leaving more revenue to be recovered from other end-users. In other words, residential end-users should be allocated network costs based on their individual network usage, regardless of which reference tariff they have selected.

Managing this dynamic is also a key consideration in setting individual prices, in step three of our cost allocation methodology.

As required by the Code, we also ensure that the level of revenue that we expect to recover from each reference tariff lies on or between:[18]

> 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:*

We explain how we estimate standalone and avoidable cost in section 5, and illustrate in Table 4.4 below how the level of revenue we expect to recover from each reference tariff falls between standalone and avoidable cost.

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

We also illustrate in Table 4.4 that the level of revenue/cost we recover from tariff components that vary with usage (variable charges) is higher than the avoidable/incremental cost of providing each service. This demonstrates partial compliance with the requirements of clause 7.6 of the Code, which requires that variable charges recover *only* the avoidable/incremental cost of providing each reference service (subpart a), with the remainder of our costs to be recovered by fixed charges (subpart b).

Full compliance with this provision would give rise to significant increases in our fixed charges. In light of feedback from users and end-use customers, we limited the increases in fixed charges and therefore recover more costs from variable charges than is required by clause 7.6 of the Code. As described in section 4.4, Western Power will endeavour to more fully comply with this requirement in the future, while managing bill impacts.

Table 4.4: Indicative allocation of revenue lies between avoidable and standalone cost – FY25

Reference tariff	Avoidable cost ($m)	Revenue recovered from tariff components that vary with usage ($m)	Indicative revenue recovered ($m)	Standalone cost ($m)
RT1	32.91	106.94	186.72	788.17
RT2	9.53	27.07	45.64	706.67
RT3	0.84	2.87	4.55	678.77
RT4	6.95	9.68	13.93	698.22
RT5	8.82	17.24	40.31	500.30
RT6	23.62	88.79	120.91	754.14
RT7	32.93	86.21	147.49	580.57
RT8	3.52	6.96	21.20	687.66
RT9	14.97	7.21	51.85	720.60
RT10	1.90	2.31	6.73	682.92
RT11	1.58	3.96	3.97	679.65
RT13	18.96	60.82	102.26	739.96
RT14	0.80	5.17	6.22	678.54

Reference tariff	Avoidable cost ($m)	Revenue recovered from tariff components that vary with usage ($m)	Indicative revenue recovered ($m)	Standalone cost ($m)
RT15	1.93	2.77	6.14	682.35
RT16	3.20	2.55	3.43	686.22
RT17	41.30	55.38	141.45	813.76
RT18	78.43	150.11	182.42	927.03
RT19	0.42	1.19	1.30	677.25
RT20	22.02	72.61	78.76	746.42
RT21	40.08	89.81	227.28	817.82
RT22	0.23	1.01	1.24	676.70
RT34	0.00	0.00	0.00	675.97
RT35	0.00	0.00	0.00	675.97
RT36	0.00	0.00	0.00	470.97
RT37	0.00	0.00	0.00	470.97
RT38	0.00	0.00	0.00	470.97
RT39	0.00	0.00	0.00	470.97
RT40	0.00	0.00	0.00	470.97
RT41	0.00	0.00	0.00	470.97

4.4 Step 3: Setting prices to recover allocated revenue

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

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

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

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

By way of illustration, for the residential customer class, we have increased fixed charges in FY24 by only two per cent above the increase required by our revenue (3.2 per cent in total)[19] broadly in line with the in our target revenue for this year.

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

Table 4.5 demonstrates for each residential reference tariff the revenue recovered from each charging component in FY24.

Table 4.5: Indicative forecast revenue recovered from residential reference tariffs in FY24 ($m)

Reference tariff	Fixed charge	Flat energy	Demand charge	On-peak energy	Shoulder energy	Off-peak energy	Overnight energy	Super off-peak energy
RT1	*99.86*	*151.34*	*0.00*	*0.00*	*0.00*	*0.00*	*0.00*	*0.00*
RT3	*1.40*	*0.00*	*0.00*	*2.02*	*0.00*	*0.65*	*0.00*	*0.00*
RT13	*50.31*	*82.93*	*0.00*	*0.00*	*0.00*	*0.00*	*0.00*	*0.00*
RT15	*2.86*	*0.00*	*0.00*	*1.89*	*0.00*	*0.66*	*0.00*	*0.00*
RT17	*68.22*	*0.00*	*0.00*	*20.69*	*3.70*	*27.36*	*0.00*	*0.00*
RT19	*0.09*	*0.00*	*1.04*	*0.03*	*0.01*	*0.05*	*0.00*	*0.00*
RT21	*113.86*	*0.00*	*0.00*	*38.34*	*16.38*	*24.62*	*8.17*	*0.00*
RT35	*41.17*	*0.00*	*0.00*	*24.19*	*0.00*	*11.06*	*0.00*	*0.08*
RT37	*5.38*	*0.00*	*7.80*	*2.35*	*0.00*	*1.07*	*0.00*	*0.01*

[19] With the exception of RT17, which has received a lower increase to bring the fixed charge into line with all other residential reference tariffs.

5. 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.*

5.1 Economic concepts

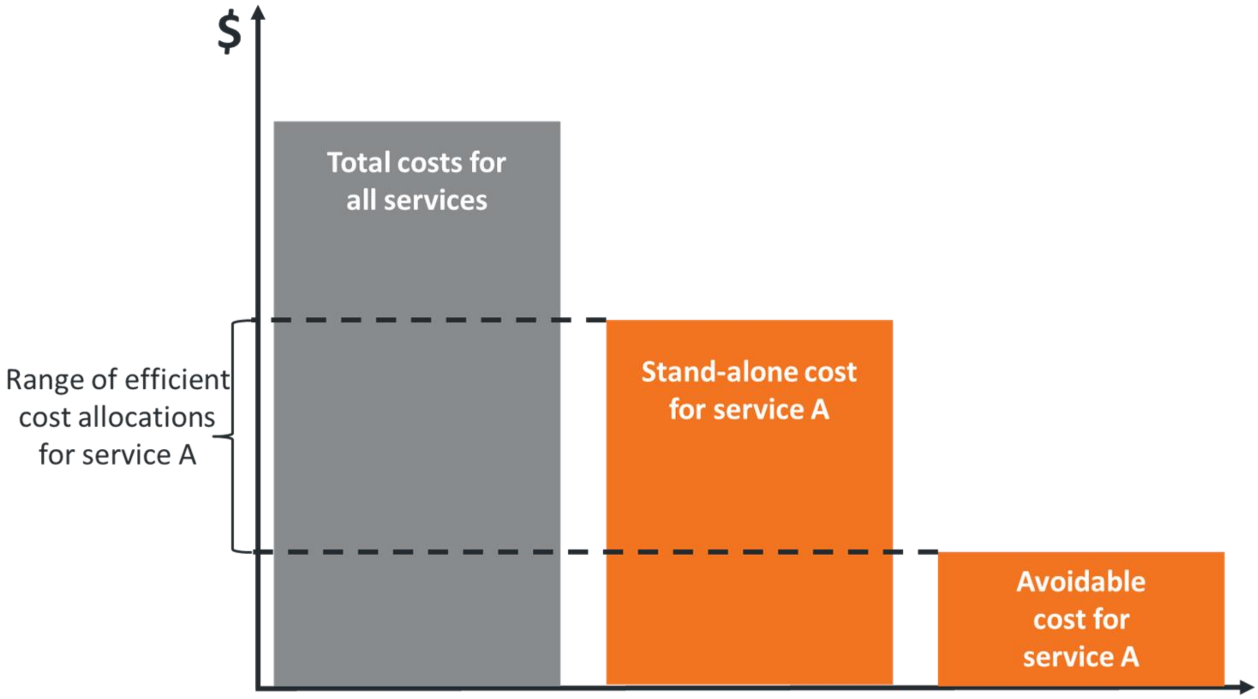
The economic concepts of stand-alone and avoidable cost reflect the principle that the amount recovered from users of any one service in a group of services using shared assets should be:

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

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

It follows that any allocation of costs within these bounds is efficient, as shown in the indicative example provided in Figure 5.1. The ultimate allocation of costs within these bounds involves a matter of equity between end-users and a degree of judgement by subject matter experts.

Figure 5.1: 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.

5.2 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.

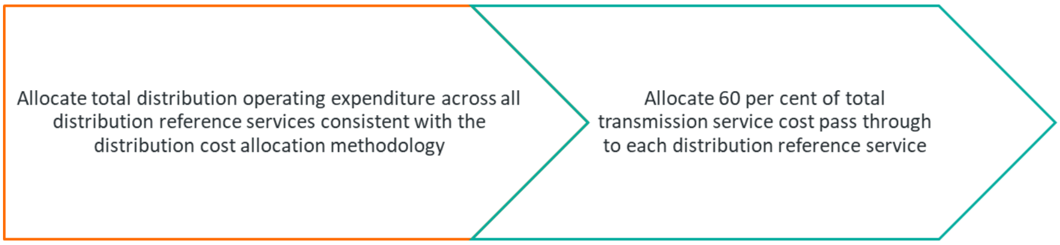
The estimation process for stand-alone and avoidable costs are discussed separately, commencing with the process for avoidable cost.

5.2.1 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 5.2.

Figure 5.2: Estimation of avoidable costs for distribution reference services



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

As described in sections 3 and 4, 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.

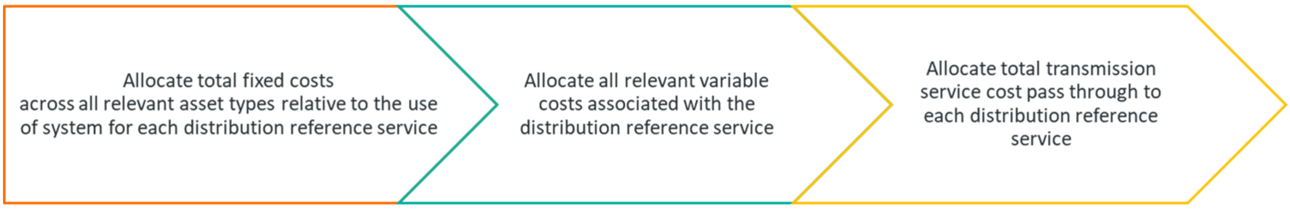
With regards to transmission connections, many components of total operating expenditure will still be necessary if certain services are not provided. In particular, the only component of total transmission operating expenditure that is avoidable is operating expenditure associated with network operations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

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

5.2.2 Stand-alone cost

The process for estimating stand-alone cost for distribution reference services is presented in Figure 5.3.

Figure 5.3: Estimation of stand-alone costs for distribution reference services



As described in sections 3 and 4, 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 5.1.

Table 5.1: Fixed and variable relative components to total costs for distribution system assets

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

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

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

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

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

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

6. Tariff structures

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

Table 6.1: Reference services and applicable tariffs

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

Reference service	Reference tariff
A14 – 3 Part Time of Use Demand (Residential) Exit Service C11 – 3 Part Time of Use Demand (Residential) Bi-directional Service	RT19
A15 – 3 Part Time of Use Demand (Business) Exit Service C12 – 3 Part Time of Use Demand (Business) Bi-directional Service	RT20
A16 – Multi Part Time of Use Energy (Residential) Exit Service C13 – Multi Part Time of Use Energy (Residential) Bi-directional Service	RT21
A17 – Multi Part Time of Use Energy (Business) Exit Service C14 – Multi Part Time of Use Energy (Business) Bi-directional Service	RT22
C15 – Bi-directional Service Facilitating a Distributed Generation or Other Non-Network Solution	RT24
D1 – Supply Abolishment Service	RT25
D2 – Capacity Allocation Service	NA[20]
D6 – Remote Load / Inverter Control Service	RT26
D8 – Remote De-energise Service	RT28
D9 – Remote Re-energise Service	RT29
D10 – Streetlight LED Replacement Service	RT30
D11 – Site Visit to Support Remote Re-energise Service	RT31
D12 – Manual De-energise Service	RT32
D13 – Manual Re-energise Service	RT33
A19 – Super Off-peak Energy (Business) Exit Service C17 – Super Off-peak Energy (Business) Bi-directional Service	RT34
A18 – Super Off-peak Energy (Residential) Exit Service C16 – Super Off-peak Energy (Residential) Exit Service	RT35
A21 – Super Off-peak Demand (Business) Exit Service C19 – Super Off-peak Demand (Business) Bi-directional Service	RT36
A20 – Super Off-peak Demand (Residential) Exit Service C18 – Super Off-peak Demand (Residential) Bi-directional Service	RT37
C22 – Transmission Storage Service	TRT3
C23 – Low Voltage Distribution Storage Service	RT38
C24 – High Voltage Distribution Storage Service	RT39

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

Reference service	Reference tariff
A22 – Low Voltage Electric Vehicle Charging Exit Service C20 – Low Voltage Electric Vehicle Charging CMD Service	RT40
A23 – High Voltage Electric Vehicle Charging Exit Service C21 – High Voltage Electric Vehicle Charging CMD 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
- 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 end-users 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 6.2 provides a high level indication for the structure of each reference tariff offered by Western Power.

Table 6.2: 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)	Export charge (c/kWh)	Annual Metered Demand	Off-Peak Discount Factor (%)	CMD/DSOC	Demand/ Length for ATMD > 1,000 kVA	Connection Component (c/kW/day)	Use of System Component (c/kW/day)	Common Service Component (c/kW/day)	Excess Network Usage	Fixed Metering Component (c/day)	Administration Component (c/day)	Charge Per Request ($)
RT1 – Anytime Energy (Residential)	No	✓	✓	✓																✓		
RT2 – Anytime Energy (Business)	No	✓	✓	✓																✓		
RT3 - Time of Use Energy (Residential)	Yes	✓	✓		✓		✓													✓		
RT4 - Time of Use Energy (Business)	Yes	✓	✓		✓		✓													✓		
RT5 - HV Metered Demand	No	✓	✓							✓		✓	✓		✓					✓		
RT6 - LV Metered Demand	No	✓	✓							✓		✓	✓		✓					✓		
RT7 - HV CMD	No	✓	✓											✓	✓				✓	✓	✓	
RT8 - LV CMD	No	✓	✓											✓	✓				✓	✓	✓	
RT9 - Streetlighting	No	✓	✓	✓																		
RT10 – Unmetered Supplies	No	✓	✓	✓																		
RT11 - Distribution Entry	No	✓												✓	✓	✓	✓		✓	✓		
RT13 – Anytime Energy (Residential) Bi-directional	No	✓	✓	✓																✓		

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)	Export charge (c/kWh)	Annual Metered Demand	Off-Peak Discount Factor (%)	CMD/DSOC	Demand/ Length for ATMD > 1,000 kVA	Connection Component (c/kW/day)	Use of System Component (c/kW/day)	Common Service Component (c/kW/day)	Excess Network Usage	Fixed Metering Component (c/day)	Administration Component (c/day)	Charge Per Request ($)
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 (Business) – new	No	✓	✓		✓	✓	✓		✓											✓		
RT35 – Super Off-peak Energy (Residential) – new	No	✓	✓		✓	✓	✓		✓											✓		

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

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)	Export charge (c/kWh)	Annual Metered Demand	Off-Peak Discount Factor (%)	CMD/DSOC	Demand/ Length for ATMD > 1,000 kVA	Connection Component (c/kW/day)	Use of System Component (c/kW/day)	Common Service Component (c/kW/day)	Excess Network Usage	Fixed Metering Component (c/day)	Administration Component (c/day)	Charge Per Request ($)
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	Yes																					✓
TRT1 – Transmission Exit	Yes		✓											✓			✓	✓	✓	✓		

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

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

6.1 Transmission reference services

6.1.1 Transmission load tariff (TRT1)

Our load tariff for transmission connections 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 end-users.

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**)[21] of the individual end-user 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.

6.1.2 Transmission generator tariff (TRT2)

Similar to our transmission load tariff, our generator tariff for transmission connections 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 end-users.

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 end-user that reflect their use of system and use of control system services;[22] and
- ENUC calculated in accordance with our ENUC principles for transmission connections.

6.1.3 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. Transmission storage devices will be treated similar to existing generators 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;
- variable charges that apply to the DSOC of the individual end-user that reflect their use of system and use of control system services;[23] and
- ENUC calculated in accordance with our ENUC principles for transmission connections.

[21] An end-user nominates a CMD that reasonably reflects their expected annual peak demand. There is a monthly penalty for any demand excursion above the CMD.

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

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

6.1.4 ENUC principles

An additional charge applies to transmission connections, 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.

6.2 Distribution reference services – residential end-users

6.2.1 Anytime energy tariffs (RT1 and RT13)

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

We offer two anytime energy tariffs, one for residential end-users that only import energy from our network (RT1) and another for residential end-users 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 end-users.

6.2.2 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 end-users, one for residential end-users that only import energy from our network (RT3) and another for residential end-users 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 end-users.

The on- and off-peak periods applicable to the residential time of use energy charges (RT3 and RT15) are presented in Table 6.3.

Table 6.3: 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

6.2.3 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 end-users, available to residential end-users 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 end-users.

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 end-users.

The on-peak, shoulder and off-peak periods applicable to the residential three part time of use energy tariff (RT17) are presented in Table 6.4.

Table 6.4: 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

6.2.4 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 end-user'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 end-users, available to residential end-users 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 end-users.

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);[24]
- 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 end-users.

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

The on-peak, shoulder and off-peak periods applicable to the residential three part time of use demand tariff (RT19) are presented in Table 6.5. We note that the same on-peak period applies to both the energy and demand components of this tariff.

Table 6.5: 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

6.2.5 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 end-users, available to residential end-users 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 end-users.

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 end-users.

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 6.6.

Table 6.6: 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

6.2.6 Super off-peak energy tariff (RT35)

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.

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

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 end-users.

The on-peak, shoulder, off-peak and super off-peak periods are presented in Table 6.7.

Table 6.7: Definition of charging windows for RT35

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

6.2.7 Super off-peak demand tariff (RT37)

The structure of our new super off-peak demand tariff is similar to the super-off peak energy tariff that we describe in the preceding section, but with the addition of a demand charge that applies in the on-peak period.

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

These reference tariffs comprise:

- 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);[25]
- 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 end-users.

The on-peak, shoulder, off-peak and super off-peak periods applicable to the residential multi part time of use energy tariff (RT37) are presented in Table 6.7.

Table 6.8: Definition of charging windows for RT37

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

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

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

6.3.1 Anytime energy tariffs (RT2 and RT14)

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

We offer two anytime energy tariffs, one for business end-users that only import energy from our network (RT2) and another for business end-users 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 end-users.

6.3.2 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 end-users, one for business end-users that only import energy from our network (RT4) and another for business end-users 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 end-users.

The on- and off-peak periods applicable to the business time of use energy charges (RT4 and RT16) are presented in Table 6.9.

Table 6.9: Definition of charging windows for RT4 and RT16

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

6.3.3 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 end-users, available to business end-users 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 end-users.

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 end-users.

The on-peak, shoulder and off-peak periods applicable to the business three part time of use energy tariff (RT18) are presented in Table 6.10.

Table 6.10: Definition of charging windows for RT18

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

6.3.4 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 end-user'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 end-users, available to business end-users 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 end-users.

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);[26]
- 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 end-users.

The on-peak, shoulder and off-peak periods applicable to the business three part time of use demand tariff (RT20) are presented in Table 6.11. We note that the same on-peak period applies to both the energy and demand components of this tariff.

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

Table 6.11: Definition of charging windows for RT20

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

6.3.5 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 end-users, available to business end-users 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 end-users.

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 end-users.

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 6.12.

Table 6.12: Definition of charging windows for RT22

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

6.3.6 Super off-peak energy tariff (RT34)

The structure of our new super off-peak 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.

It applies to small business end-users that only import energy from our network (exit services) and to those that both import and export energy from our network (bidirectional services).

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 end-users.

The on-peak, shoulder, off-peak and super off-peak periods are presented in Table 6.7.

Table 6.13: Definition of charging windows for RT34

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

6.3.7 Super off-peak demand tariff (RT36)

The structure of our new super off-peak demand tariff is similar to the super-off peak energy tariff that we describe in the preceding section, but with the addition of a demand charge that applies in the on-peak period.

It applies to small business end-users that only import energy from our network (exit services) and to those that both import and export energy from our network (bidirectional services).

These reference tariffs comprise:

- 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);[27]
- 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 end-users.

The on-peak, shoulder, off-peak and super off-peak periods applicable to the residential multi part time of use energy tariff (RT36) are presented in Table 6.7.

Table 6.14: Definition of charging windows for 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

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

6.4 Distribution reference services – large business end-users

6.4.1 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 an end-user measured over a rolling 12-month period, measured in kVA.[28] However, these variable demand charges are subject to a discount that is calculated by reference to the energy usage of the end-user 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;[29] and
- a fixed, daily metering charge that reflects the metering reference service we provide to these end-users.

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 an end-user 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 6.15.

Table 6.15: 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

[28] Measuring demand in kVA, as distinct to kW, provides an incentive for customers to manage their power factor as close to unity as possible.
[29] 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.

6.4.2 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),[30] 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;[31] and
- a fixed, daily metering charge that reflects the metering reference service we provide to these end-users.

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 an end-user 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 6.16.

Table 6.16: 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

6.4.3 High voltage contract maximum demand tariff (RT7)

Our high voltage contract maximum demand tariff is distinct from other business tariffs in that the end-user 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 end-users to manage their power factor as close to unity as possible.

[30] Measuring demand in kVA, as distinct to kW, provides an incentive for customers to manage their power factor as close to unity as possible.
[31] 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.

This reference tariff comprises:

- a fixed, daily charge for access to our network, which is waived for end-users 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 end-users;
- a fixed, daily administration charge; and
- ENUC calculated in accordance with our ENUC principles.

This tariff also applies to the high voltage EV charging CMD bi-directional reference service under RT41.

6.4.4 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 end-users to nominate a CMD, exceedance of which will result in penalty charges. Similarly, charges are applied per kVA to incentivise end-users 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 end-users 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 end-users;
- a fixed, daily administration charge; and
- ENUC calculated in accordance with our ENUC principles.

This tariff also applies to the low voltage EV charging CMD bi-directional reference service under RT40.

6.5 Distribution reference services – other

6.5.1 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.

6.5.2 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 point 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.

6.5.3 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 end-users.

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 end-user that reflect their use of system and use of control system services;[32]
- 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 end-user and the voltage level at which the connection is located; and
- ENUC calculated in accordance with our ENUC principles.

6.5.4 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 end-user 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

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

costs or non-capital costs reducing as a result of the entry point for the distributed generating plant or other non-network solution being located in that particular part of the covered network, the discount to be applied is an annualised discount amount (which can be no greater than the annual charge), calculated as the present value of FCp less FCn over a period of Y years using discount rate W.

Where:

- FCp is the present value of the Western Power committed forecast capital-related costs and non-capital costs that would be incurred over Y years if the facilities and equipment (including distributed generating plant) were not to connect to the Western Power Network.
- FCn is the present value of Western Power's forecast capital-related costs and non-capital costs over Y years that are anticipated to be incurred if the facilities and equipment (including distributed generating plant) were to connect to the Western Power Network.
- Y is the period over which the present value assessment is to occur which is 15 years unless otherwise agreed between Western Power and the user.
- W is the Weighted Average Cost of Capital as set out in section 5.4 of the Access Arrangement that applies in the pricing year.

6.5.5 Distribution storage service tariffs (RT38 and RT39)

We are introducing two new tariffs for distribution-connected storage services, ie:

- a distribution storage service tariffs for low voltage connections – RT38; and
- a distribution storage service tariffs for high voltage connections – RT39.

These tariff both have the same structure and comprise:

- a fixed, daily charge for access to our network that reflects the costs of providing connection assets;
- a fixed, daily metering charge per meter;
- a super-off-peak, off-peak, shoulder and on-peak energy charge; and
- an on-peak demand charge; and
- export charges (measured in cents per kWh) that are:
  - near-zero outside of the solar soak period;
  - low for the first 3kWh of exports during the solar soak period each day; and
  - then slightly higher for exports above 3 kWh in the solar soak period each day.

Our distribution storage service tariffs provide 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 our distribution storage service tariffs are presented in Table 6.17.

Table 6.17: Definition of charging windows for RT38 and RT39

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

6.5.6 Electric vehicle charging service tariffs (RT40 and RT41)

We are introducing two new tariffs for dedicated EV charging stations, ie:

- a tariff for dedicated EV charging stations connected to the low voltage network – RT40; and
- a tariff for dedicated EV charging stations connected to the high voltage network – RT41.

These tariffs have the same structure and comprise:

- a fixed, daily charge for access to our network that reflects the costs of providing connection assets;
- a fixed, daily metering charge per meter;
- a sliding scale of demand charges that increase with utilisation, and remain at zero until 15 per cent utilisation is reached;
- a sliding scale of off-peak and on-peak energy charges that increase with utilisation.

The sliding scale of demand and energy charges increase by reference to 10 per cent increments in utilisation. The marginal price is constant from 30 per cent utilisation upwards.

Western Power has designed the measure of utilisation to provide strong support to EV charging stations during this access period, ie, the measure of network use:

- excludes demand in the twelve 30-minute intervals between 9am and 3pm (being the solar soak period in other tariffs); and
- excludes the first 10kW of demand in any 30-minute interval.

It follows that network utilisation is measured as:

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

The on-peak and off-peak periods applicable to the electric vehicle charging service tariffs (RT40 and RT41) are presented in Table 6.18.

Table 6.18: Definition of charging windows for RT40 and RT41

Everyday	
On-peak	**Off-peak**
3:00pm – 9:00pm	All other times

6.5.7 Other charging components (RT25 to RT33)

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

- RT25 consists of a charge per connection point supply abolishment;

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

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.

7. Price setting for transmission reference services

In this section, we explain the price setting process for end-users connected to our transmission network. Specifically, we present the methodology by which we set prices for:

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

7.1 Calculation of total efficient costs for transmission reference services

This section details the efficient cost estimation methodology as it pertains to our transmission system.

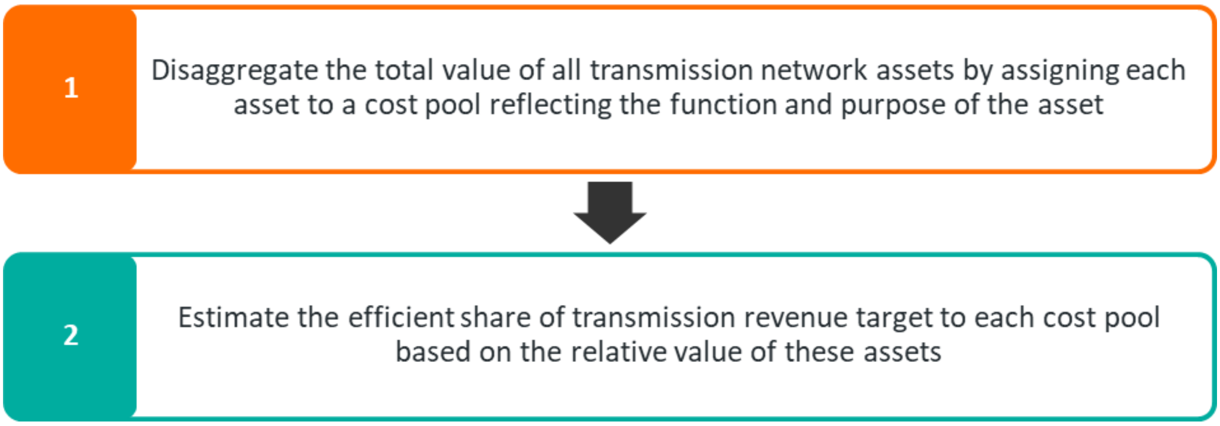
The efficient cost estimation methodology for the transmission system is a process by which the relative contribution to our total efficient costs for transmission system services is caused by:

- each individual transmission connection; and
- all distribution system connected end-users, as these end-users also use, and therefore must contribute to the cost of, the transmission system.

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

The estimation of the efficient contribution of transmission reference services to total transmission costs follows the high-level process detailed in Figure 7.1.

Figure 7.1: Transmission services efficient cost estimation flow chart



The remainder of this section provides a detailed description and explanation of the steps presented in Figure 7.1 (including what our asset pools are).

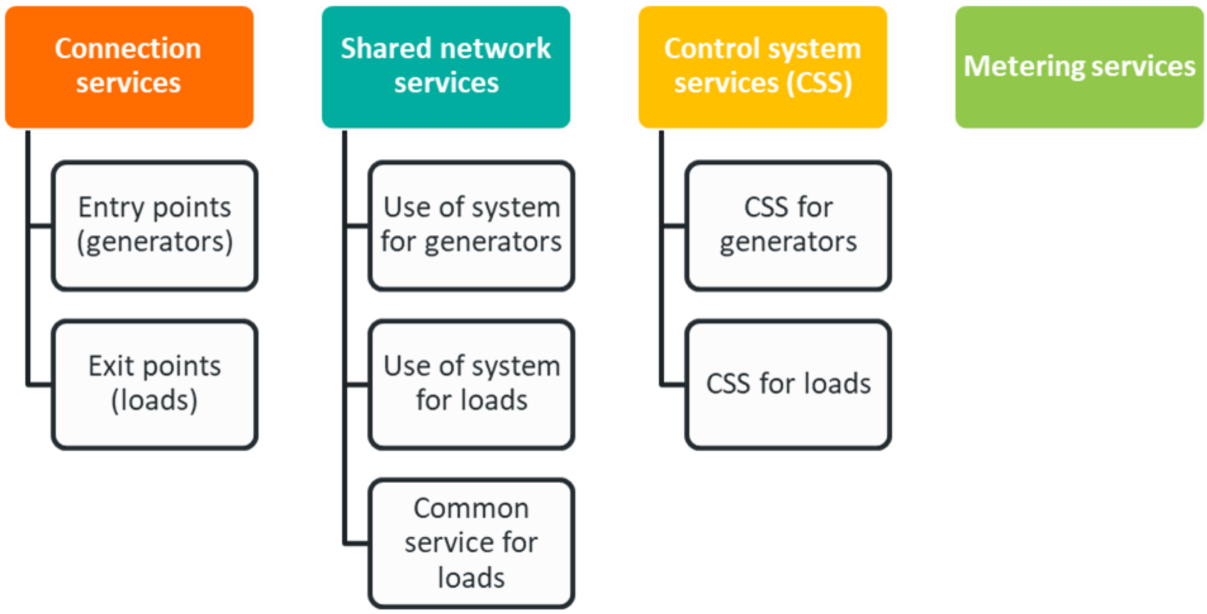
7.1.1 Step 1 - definition of transmission service cost pools

Fundamental to the efficient cost estimation methodology for transmission reference services is the establishment of cost pools to which transmission revenue is disaggregated. In the context of the transmission network efficient cost estimation 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 end-users – assigned to the connection services cost pool;
- voltage control services – assigned to both the connection services and shared network services cost pools as voltage control is partly location specific, allocated to connection services, and partly whole of system related, allocated to shared network services;
- supporting the general functionality of the transmission network, such as transmission substations and poles and lines that are not directly attributable to the connection of a particular end-user – assigned to the shared network services cost pool;
- providing control services across the transmission network, such as SCADA assets and SCADA control systems – assigned to the control system services (CSS) cost pool; and
- metering for transmission connected end-users – assigned to the metering services cost pool.

The transmission service cost pools are presented in Figure 7.2.

Figure 7.2: Transmission service cost pools



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

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

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

In addition, the assignment of transmission network assets and transmission cost of service to cost pools is further segmented by an assignment between the two distinct transmission end-user types, generators, and loads. Table 7.1 presents the nature by which the cost pools are further segmented to generators and loads.

Table 7.1: Assignment of transmission cost pools between loads and generators

Transmission cost pools	Loads (exit points)	Generators (entry points)
Connection services	• Specific exit connection assets • 33 per cent of the value of voltage control assets at exit connection points	• Specific entry connection assets • 33 per cent of the value of voltage control assets at entry connection points
Use of system (shared network services)	• 50 per cent of the total value of shared network service assets	• 20 per cent of the total value of shared network service assets
Common service (shared network services)	• 30 per cent of the total value of shared network service assets • 67 per cent of the value of voltage control assets at both exit and entry connection points	• *None*
CSS	• Total CSS costs proportioned based on the total number of load control points	• Total CSS costs proportioned based on the total number of generator control points
Metering	• Total metering costs proportioned based on the number of transmission network connected loads	• Total metering costs proportioned based on the number of transmission network connected generators

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

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

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

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

Table 7.2 presents the process by which we estimate the efficient contribution to total transmission target revenue from each 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 the efficient revenue of each cost pool will be equal to the transmission target revenue each year.

Table 7.2: Calculation of transmission cost allocation

Transmission cost pool	Cost pool asset value	Efficient revenue
Connection (exit)	$V_{\text{Exit connection}}$	$V_{\text{Exit connection}} \times RR$
Connection (entry)	$V_{\text{Entry connection}}$	$V_{\text{Entry connection}} \times RR$
Use of system (exit)	$V_{\text{Exit UOS}}$	$V_{\text{Exit UOS}} \times RR$
Use of system (entry)	$V_{\text{Entry UOS}}$	$V_{\text{Entry UOS}} \times RR$
Common service	V_{CS}	$V_{\text{CS}} \times RR$
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}
Total asset valuation excluding CSS and metering	$V_{\text{All}} = \sum V_{\text{Cost Pools}} - V_{\text{Exit CSS}} - V_{\text{Entry CSS}} - V_{\text{Metering}}$	
Revenue rate of return	$RR = \frac{\text{Rev} - V_{\text{Exit CSS}} - V_{\text{Entry CSS}} - V_{\text{Metering}}}{V_{\text{All}}}$	

Table 7.3 presents the efficient contribution of total transmission revenue from each of the cost pools, which underpins the share of transmission target revenue assigned to each cost pool each year.

Table 7.3: Efficient share of transmission service revenue to cost pools over the AA5 period

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

7.1.3 Implementation considerations for efficient transmission service cost estimation

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

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

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

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

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

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

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

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

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

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

7.2 Price setting for new transmission nodes

This policy applies when a new transmission node is established.

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

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

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

Policy Statement – Transmission Use of System Price (TUOS)

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

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

Policy Statement – Transmission Connection Price

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

A connection that is unlikely to be shared by other users

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

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

The annual connection price is calculated to recover 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 selects this option the calculation of the capital contribution and the associated connection access price is on the same basis as the first option.

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

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

8. 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 5.4 of the TSS Overview.

Consistent with the cost allocation process described in sections 3 and 4, each reference service is allocated a portion of total costs that reflects the efficient costs of serving the end-users 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 the AA5 period.

We calculate the weighted average price change for a reference tariff using:

- indicative prices for each year of AA5; and
- volume estimates for the first year of AA5 (FY23), ie, connection numbers, total energy consumption and maximum demand.

By calculating revenue using a common set of volume inputs, the calculated change in revenue between years is attributed solely to the change in the price of individual tariff components between years.

9. Compliance checklist

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

Table 9.1: 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 6 ***(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 8
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 5
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, and 4
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 3 and 4
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 and 4
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 6
7.3J	A reference tariff must comply with this Code and all relevant written laws and statutory instruments.	Noted.

Clause	Requirement	Relevant sections
Tariff components		
7.6	Unless a tariff structure statement containing alternative pricing methods would better achieve the Code objective, for a reference service: a) the incremental cost of service provision should be recovered by tariff components that vary with usage or demand; and b) any amount in excess of the incremental cost of service provision should be recovered by tariff components that do not vary with usage or demand.	Technical summary, section 4