Preliminary framework and approach

SA Power Networks
Regulatory control period commencing 1 July 2020

March 2018

AUSTRALIAN ENERGY REGULATOR

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Contents

Shortened forms

Shortened Form	Extended Form
AEMC	Australian Energy Market Commission
AER	Australian Energy Regulator
Allowance Mechanism	demand management innovation allowance mechanism
capex	capital expenditure
CESS	capital expenditure sharing scheme
COAG	Council of Australian Governments
CPI	consumer price index
DMIS	demand management incentive scheme
distributor, DNSP	distribution network service provider
DUoS	distribution use of system
EBSS	efficiency benefit sharing scheme
expenditure assessment guideline	expenditure forecast assessment guideline for electricity distribution
GSL	guaranteed service level
F&A	Framework and approach
kWh	kilowatt hours
NEM	National Electricity Market
NEO	National Electricity Objective
NER or the rules	National Electricity Rules
next regulatory control period	1 July 2020 to 30 June 2025
opex	operating expenditure
RAB	regulatory asset base
STPIS	service target performance incentive scheme

Overview

The F&A is the first step in a two year process to determine efficient prices for electricity distribution services in SA. The F&A determines, amongst other things, which services we will regulate and the broad nature of the regulatory arrangements. This includes an assessment of services (service classification) and whether we need to directly control the prices and/or revenues set for those services. The F&A also facilitates early consultation with consumers and other stakeholders and assists electricity distribution businesses prepare regulatory proposals.

This preliminary F&A outlines changes we are proposing to make that will affect the regulated services offered by SA Power Networks in the future.

Our preliminary view is that the F&A should be revised to reflect rule changes and the development of new incentive schemes and regulatory guidelines that will apply to SA Power Networks. In particular, late last year, the Australian Energy Market Commission (AEMC) changed the NER to amend the framework we use to classify DNSPs' electricity distribution services.[1] Power of Choice reforms that also commenced last year have introduced metering contestability to residential electricity consumers fundamentally changing the role of SA Power Networks in the provision of meters.[2] Further, we developed a new demand management incentive scheme (DMIS) and innovation allowance mechanism (Allowance Mechanism)3 and have implemented a national Ring-fencing Guideline.4 These changes to the regulatory environment that SA Power Network operates in have been reflected in this preliminary F&A.

Following release of this Preliminary F&A we will consult with interested parties before issuing our final F&A by 31 July 2018. Table 1 summarises our SA distribution determination process.

Table 1 South Australia distribution determination process

Step	Date
AER publishes preliminary F&A for SA Power Networks	March 2018
Stakeholder forum	17 April 2018
Submissions on the preliminary F&A for SA Power Networks close	27 April 2018

1 AEMC, final rule determination - National Electricity Amendment (Contestability of Energy Services) 2017

2 See: http://www.aemc.gov.au/Major-Pages/Power-of-choice.

3 See: https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/demand-management-incentive-scheme-and-innovation-allowance-mechanism.

4 AER, *Ring-fencing guideline electricity distribution,* Version 2. October 2017. See https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/electricity-ring-fencing-guideline-october-2017.

AER to publish final F&A for SA Power Networks	July 2018
SA Power Networks submits its regulatory proposal to AER	January 2019
AER publishes issues paper and holds public forum	March/April 2019*
Submissions on regulatory proposal close	May 2019
AER to publish draft decision	September 2019
AER to hold a predetermination conference	October 2019
SA Power Networks to submit revised regulatory proposal to AER	December 2019
Submissions on revised regulatory proposal and draft decision close	January 2020*
AER to publish distribution determination for regulatory control period	April 2020

* The date provided is based on the AER receiving compliant proposals. The date may be altered if we receive non-compliant proposals.

Source: NER, chapter 6.

Background

The Australian Energy Regulator (AER) is the economic regulator for transmission and distribution electricity and gas network businesses across Australia (excluding Western Australia). Our powers and functions for the electricity sector are set out in the National Electricity Law (NEL) and National Electricity Rules (NER).

SA Power Networks (SAPN) is the licensed, regulated operator of South Australia's (SA) monopoly electricity distribution network. The network comprises the poles, wires and transformers used for transporting electricity across urban and rural population centres to homes and businesses. SA Power Networks designs, constructs, operates and maintains its distribution network for SA electricity consumers.

We make regulatory decisions on the revenues SA Power Networks can recover from its customers. We determine SA Power Networks' revenue by an assessment of its efficient costs and forecasts. Our assessment is based on a regulatory proposal submitted by SA Power Networks in advance of a regulatory control period, in this case beginning 1 July 2020. Regulatory proposals set out the network businesses' views on their expected costs, services, incentive schemes and required revenues. Our regulatory determinations set out our decisions on these issues.

The regulatory framework we administer is based on an incentive regime. We set a network business' allowed revenue for a period (typically five years) based on the best available information, rigorous assessment and consideration of consumers' views. Network businesses are then provided with incentives to outperform the revenue we determine. A network business retains any savings for a period time before those savings are passed to customers through lower network bills.

This chapter provides an overview of our preliminary position on:

- classification of distribution services (which services we will regulate)
- control mechanisms (how we will determine prices for regulated services)
- incentives schemes for service quality, capital expenditure and operating expenditure and demand management
- expenditure forecasting tools to test the network business' regulatory proposals
- how we will calculate depreciation of the network business' regulatory asset bases
- how we will price transmission assets (dual function assets).

A summary our intended approach to each of the above matters is provided below. More detailed discussion of each matter is set out in the following chapters.

Classification of distribution services

We regulate most distribution services provided by SA Power Networks. Service classification determines which services will be regulated and how. We will regulate services that are provided on a monopoly basis under a price or revenue cap, directly controlling the charges that a distributor can levy customers. Less prescriptive regulation is required where prospect of competition exists. In some situations we may remove regulation altogether—unregulated distribution services must be provided through either a separate affiliate to the distributor or the distributor must demonstrate functional separation,[5] following the introduction of our Ring-Fencing Guideline.[6]

In broad terms, this means that while existing regulated distribution services will continue to be provided by the distributor, all unregulated distribution services or new services that come into existence within a regulatory control period must be provided separately to the regulated network business, unless it applies for, and receives, a waiver under the Ring-fencing Guideline.

Further, the Australian Energy Market Commission (**AEMC**) made a rule change to the NER in December 2017 which applies to the regulatory process for SA Power Networks for 2020−25.[7] In short, the rule change made it easier for the AER to change the classification

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5 Functional separation may include physical separation of offices, staff separation, accounting separation and separate branding/avoiding cross-promotion. See AER, *Ring-fencing guideline electricity distribution*, October 2017; AER, *Electricity distribution ring-fencing guideline explanatory statement*, Version 2 October 2017, available at https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/electricity-ring-fencing-guideline-october-2017 and https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/ring-fencing-guideline-electricity-distribution-december-2016.

6 AER, *Ring-fencing guideline electricity distribution*, October 2017; AER, *Electricity distribution ring-fencing guideline explanatory statement*, October 2017.

7 AEMC, final rule determination - National Electricity Amendment (Contestability of Energy Services) 2017

of services regardless of how services have been historically classified. More specifically, the rule change removed the requirement for the AER to not alter service classification unless another classification is clearly more appropriate.[8] This mandatory requirement had previously constrained our ability to move away from the status quo when considering service classification.[9]

Table 12 provides an overview of the service classifications available to us for the purposes of economic regulation under the NER.

Table 2 Classifications of distribution services

Classification		Description	Regulatory treatment
Direct control service	Standard control service	Services that are central to electricity supply and therefore relied on by most (if not all) customers such as building and maintaining the shared distribution network. Most distribution services are classified as standard control.	We regulate these services by determining prices or an overall cap on the amount of revenue that a DNSP may earn for all standard control services. The costs associated with these services are shared by all customers via their regular electricity bill.
	Alternative control service	Customer specific or customer requested services. These services may also have potential for provision on a competitive basis rather than only by the local distributor.	We set service specific prices to provide a reasonable opportunity to enable the distributor to recover the efficient cost of each service from customers using that service.
Negotiated service		Services we consider require a less prescriptive regulatory approach because all relevant parties have sufficient countervailing market power to negotiate the provision of those services.	Distributors and customers are able to negotiate service and price according to a framework established by the NER. We are available to arbitrate if necessary.
Unclassified distribution services		Distribution services that are contestable will not be classified.	We have no role in regulating these services.
Non-distribution services		Services that are not distribution services. [10]	We have no role in regulating these services.

Source: AER

8 Formerly clause 6.2.1(d), now deleted.

9 The rule change also requires us to develop and publish service classification guidelines by September 2018, which will provide further clarity and transparency around how we classify services. See clause 6.2.3A.

10 The NER defines a distribution service as a service provided by means of, or in connection with, a distribution system. NER, Chapter 10, glossary.

Our preliminary position is to change the classification of a number of SA Power Networks' distribution services for the 2020−25 regulatory control period. This will particularly apply to services which were classified as negotiated distribution services for the 2015-20 regulatory control period. Changes to this classification are necessary, in part due to the implementation of our Ring-fencing Guideline, which requires functional and legal separation between the delivery of direct control services and contestable electricity services, which includes negotiated distribution services and non-distribution services.

In December 2017, we granted SA Power Networks a waiver from certain ring-fencing obligations so that SA Power Networks would not have to separate its negotiated distribution services.[11] Ring-fencing requires regulated services to be separated from services offered into contestable markets. Our Ring-fencing Guideline introduced more stringent ring-fencing obligations and this has caused many distributors, including SA Power Networks, to reconsider how existing services are classified. Reclassifying SA Power Networks' negotiated distribution services as alternative control services would allow SA Power Networks to continue to offer these services without breaching the Ring-fencing Guideline.

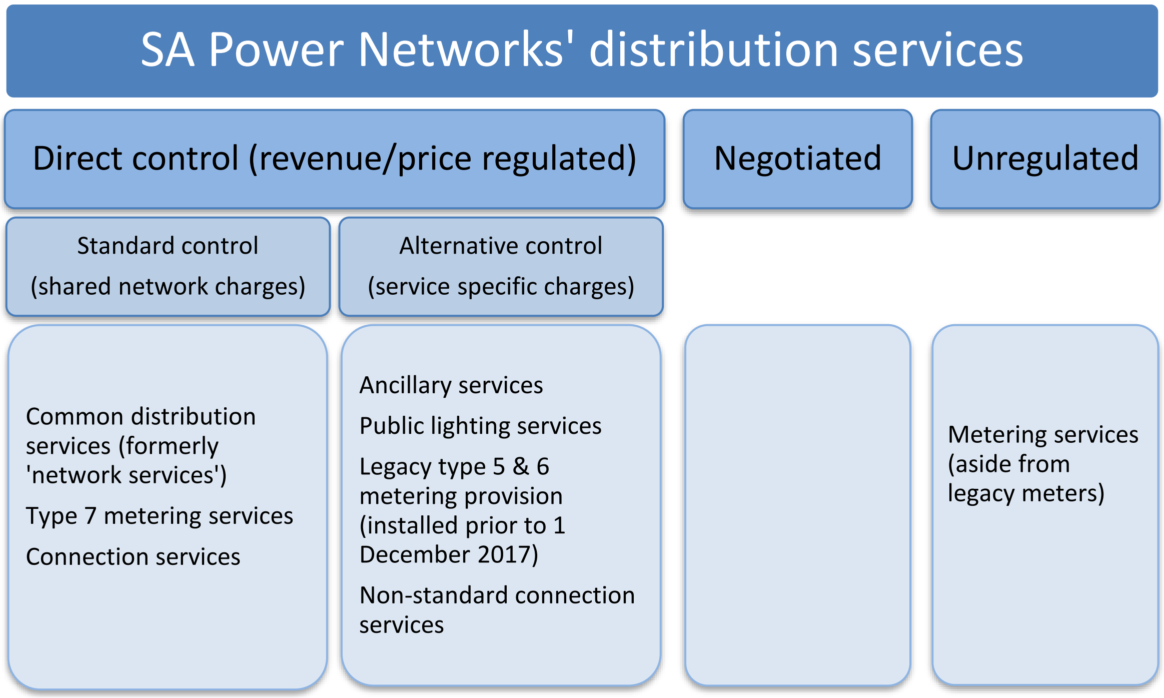
However, classification decisions are made having regard to each service and the nature of the market in which it is offered. Classification decisions are not made with the objective of merely minimising ring-fencing compliance costs. The current negotiated services, such as public lighting, are exclusively provided by SAPN as a monopoly service and should be regulated as an alternative control service. This is a matter we considered in previous F&As and up to now decided to maintain the position that existed under the previous jurisdictional approach. We have now re-considered this issue in the light of how these services have been provided and have decided they should be regulated more directly as ACS. A detailed list of these services is set out in appendix B.

Our changes to SA Power Networks' classification of services also seeks to clarify service descriptions to better align with the services being provided and create consistency and predictability across jurisdictions as far as practicable in how distribution services might be classified.

An overview of our proposed service classifications for SA Power Networks is set out in figure 1 below.

11 See https://www.aer.gov.au/networks-pipelines/ring-fencing/ring-fencing-waivers/sa-power-networks-ring-fencing-waiver-august-2017

Figure 1 AER proposed classification of SA Power Networks' distribution services



Source: AER

Our final F&A decision on service classification is not binding for our determination on SA Power Networks' regulatory proposal. However, under the NER we may only change our classification approach if there has been a material change in circumstances, justifying a departure from our final F&A position.[12]

Form of control

Following on from service classifications, our determinations impose controls on direct control service prices and/or their revenues.[13] We may only accept or approve control mechanisms in a distributor's regulatory proposal if they are consistent with our final F&A, unless we consider there has been a material change in circumstances and we consider no form of control mechanism set out in that paper should apply to that distribution service.[14] In deciding control mechanism forms, we must select one or more from those listed in the NER.[15] These include price schedules, caps on the prices of individual services, weighted average price caps, revenue caps, average revenue caps and hybrid control mechanisms.

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12 NER, cl. 6.12.3(b).
13 NER, cl. 6.2.5(a).
14 NER, cl. 6.12.3(c).
15 NER, cl. 6.2.5(b).

Our preliminary position on the form of control mechanisms for SA Power Networks is:

- standard control services— revenue cap
- alternative control services— caps on the prices of individual services.

For standard control services the NER mandate the basis of the control mechanism must be the prospective CPI–X form or some incentive-based variant.[16]

Our final F&A decision on the form of control is binding on us and SA Power Networks for the 2020−25 regulatory determination.[17] We may only vary our proposed control mechanism formulas in response to a material change in circumstances.[18]

Incentive schemes

Incentive schemes encourage network businesses to manage their networks in a safe, reliable manner that serves the long term interests of consumers. They provide network businesses with incentives to only incur efficient costs and to meet or exceed service quality targets. Our proposed position is to apply each of the following incentive schemes to SA Power Networks:

- Service Target Performance Incentive Scheme (STPIS)
- Efficiency Benefit Sharing Scheme (EBSS)
- Capital Expenditure Sharing Scheme (CESS)
- Demand Management Incentive Scheme (DMIS) and Innovation Allowance Mechanism (Allowance Mechanism).

Our final F&A approach on the application of incentive schemes is not binding on us or SA Power Networks.[19]

Application of our Expenditure Forecast Assessment Guideline

Our Expenditure Forecast Assessment Guideline[20] is based on a reporting framework allowing us to compare the relative efficiencies of distributors. Our proposed position is to apply the guideline, including its information requirements, to SA Power Networks in the 2020−25 regulatory control period.

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16 NER, cl. 6.2.6(a). The basis of the form of control is the method by which target revenues or prices are calculated e.g. a building block approach.

17 NER, cl. 6.8.1(b)(1)(i).

18 NER, cl. 6.12.3(c1).

19 We note SA power Networks' submissions that we should remain open to consideration through the F&A process of possible ideas for a Small-Scale Incentive Scheme, but it does not yet propose any such scheme. See: SA Power Networks, *Request to replace framework and approach*, 31 October 2017, p. 3.

20 AER, *Expenditure Forecast Assessment Guideline for Distribution*, November 2013.

Our expenditure assessment guideline outlines a suite of assessment/analytical tools and techniques to assist our review of SA Power Networks' regulatory proposal. We intend to apply the assessment/analytical tools set out in the guideline and any other appropriate tools for assessing expenditure forecasts.[21]

Our final F&A approach on the application of our guideline is not binding.

Depreciation

When we roll forward SA Power Networks' regulatory asset base (RAB) for the upcoming regulatory control period, we must adjust for depreciation. Our preliminary position is to use depreciation based on forecast capex (known as forecast depreciation) to establish the opening RAB as at 1 July 2025. In combination with our proposed application of the CESS, this approach will maintain incentives for SA Power Networks to pursue capex efficiencies. These improved efficiencies will benefit consumers through lower regulated prices.

Our final F&A position on the depreciation approach is not binding.

Dual function assets

Dual function assets are high-voltage transmission assets forming part of a distribution network. We decide whether to price dual function assets according to transmission or distribution pricing rules.

SA Power Networks does not own or operate any dual function assets. As such we are not required to make a decision on the application of either transmission or distribution pricing rules.

Consumer engagement

Consumer engagement is becoming increasingly important in the development of proposals by network businesses. The increased focus on consumer engagement has led network businesses to commence engagement activities with their consumer groups much earlier in the regulatory process than ever before.

SA Power Networks' engagement program commenced in early 2017 with preliminary customer research to understand customer sentiment and priorities. This informed subsequent engagement in 2017, exploring key themes of network price, reliability and

21 As part of the continuous improvement of our economic benchmarking techniques that are captured in our expenditure assessment guideline, we are reviewing and refining our analysis of operating environment factors in consultation with industry and other interested parties. In undertaking this review, we have engaged economic and engineering consultants Sapere Research Group and Merz Consulting. This consultation is ongoing. More information is available at https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/review-of-operating-environment-factors-for-distribution-network-service-providers.

resilience, and network of the future. Engagement included deliberative-style workshops, focus groups, and online engagement.

In 2018 SA Power Networks' program narrows to explore complex topics with stakeholders in dedicated ‘deep dive’ workshops. Outcomes of the engagement will help refine the plans that will form the basis of the Draft Plan/Tariff Structure Statement, due for release at the end of July 2018. SA Power Networks will seek feedback on positions ahead of lodging its regulatory proposal in January 2019. SA Power Networks is also engaging with councils and other interested stakeholders on public lighting for the 2020-25 period.

More information can be found at https://www.talkingpower.com.au.

1 Classification of distribution services

This chapter sets out our preliminary position on the classification of distribution services provided by SA Power Networks in the 2020−25 regulatory control period. Our proposed approach to classification for 2020-25 period largely mirrors that of the current period with one significant exception: the proposed reclassification all negotiated services as alternative control services, as discussed later in this chapter.

Service classification determines the nature of economic regulation, if any, applicable to distribution services. Applying the classification process prescribed in the NER, we may classify services so that we:

- directly control prices of some distribution services[22]
- allow parties to negotiate services and prices and only arbitrate disputes if necessary, or
- do not regulate some distribution services at all.

Our classification decisions therefore determine which services we will regulate and how distributors will recover the cost of providing those regulated services.

Our Ring-fencing Guideline for electricity distributors, which came into effect in December 2016, has prompted DNSPs to review the classification of services they provide. Our classification decisions will also settle ring-fencing obligations that will apply to SA Power Networks for the 2020−25 regulatory control period.[23]

The Australian Energy Market Commission (AEMC) recently made changes to the NER, following two rule change proposals, from the Council of Australian Governments Energy Council and the Australian Energy Council, on contestability of energy services.[24] As part of the rule change, we are required to develop and publish service classification guidelines by 30 September 2018. More specifically, the NER has removed the requirement for us to maintain the current service classification unless another classification is clearly more appropriate. By removing this provision to maintain the status quo, it provides an opportunity to improve clarity, achieve greater consistency across jurisdictions as far as practicable, greater predictability in how distribution services might be classified, and service descriptions that better align with the services being provided.

The service classification guideline will not be binding on the AER. However, we are required to provide reasons for any departure from the guideline to provide transparency to

22 Control mechanisms available for each service depend on their classification. Control mechanisms available for direct control services are listed by clause 6.2.5(b) of the NER. These include caps on revenue, average revenue, prices and weighted average prices. A fixed price schedule or a combination of the listed forms of control are also available. Negotiated services are regulated under part D of chapter 6 of the NER.

23 AER, *Ring-fencing guideline electricity distribution*, Version 2 October 2017; AER, *Electricity distribution ring-fencing guideline explanatory statement*, October 2017.

24 See http://www.aemc.gov.au/Rule-Changes/Contestability-of-energy-services.

stakeholders in circumstances where our approach differs from that in the classification guideline.

As part of the consultation process for the development of the guideline, we produced an issues paper inviting submissions by interested parties. In response, we received eight submissions from industry stakeholders on a broad range of issues, which can be found on the AER website.

As a result, of the new obligations, we have made changes to service classifications as shown in appendix B, reflecting improved service descriptions, alignment with other jurisdictions and to address the change in circumstances caused by new ring-fencing obligations.

1.1 AER's preliminary position

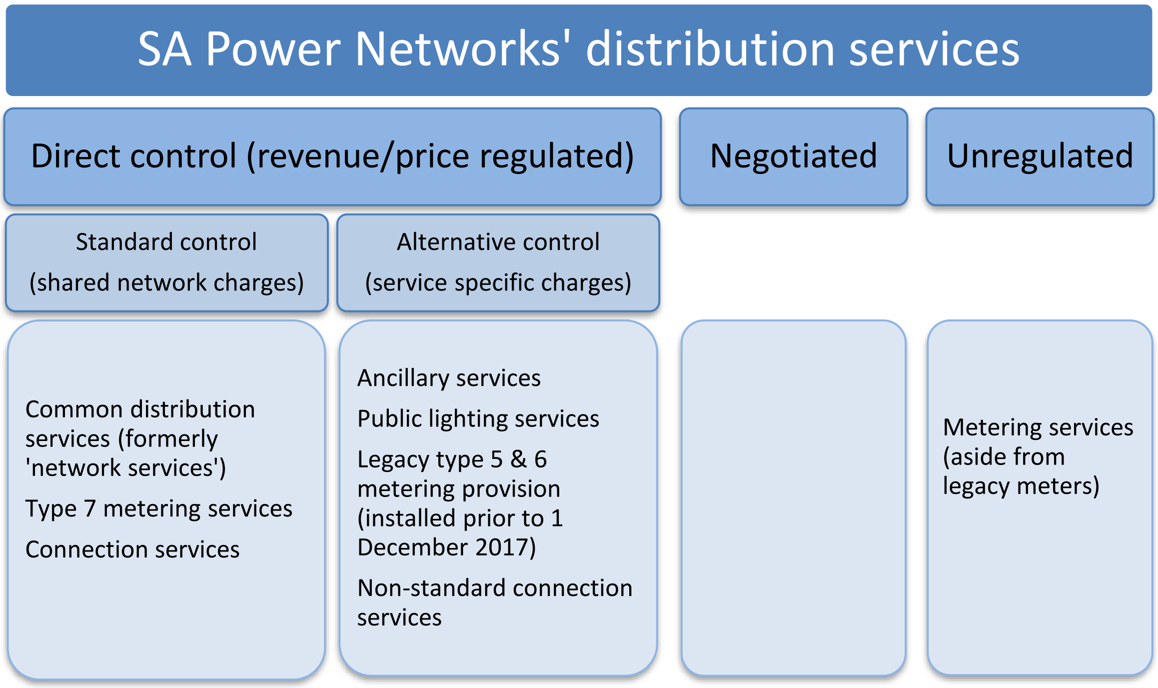
Overall, our preliminary position is to change the classification of many of SA Power Networks' distribution services for the 2020−25 regulatory control period.

Our preliminary position is to group distribution services provided by SA Power Networks as:

- common distribution services (formerly 'network services')
- ancillary services
- metering services
- connection services
- public lighting services
- unregulated distribution services.

Figure 1.1 summarises our preliminary classification of SA Power Networks' distribution services. Our assessment approach and reasons follow.

Figure 1.1 AER proposed approach to classification of SA Power Networks' distribution services



Source: AER

1.2 AER's assessment approach

In conducting our assessment of distribution service classification, we commence on the basis that we:

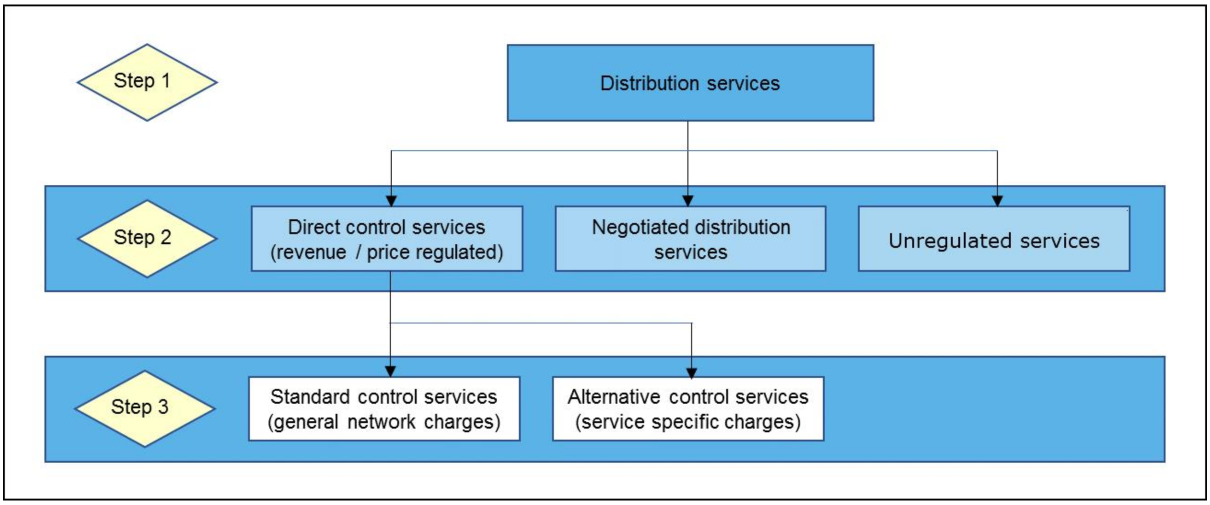
- classify the service, rather than the asset[25] – we can only decide on service classification if we understand the service being provided. That is, distribution service classification involves the classification of services distributors directly supply to customers. It does not involve the classification of:
    - the assets used to provide such services
    - the inputs/delivery methods distributors use to provide such services to customers, or
    - services that consumers or other parties provide to distributors.

25 The AEMC's Contestability of energy services rule change, made in December 2017, introduced a requirement for the AER to regulate 'restricted assets'. The AER does not classify assets as restricted assets; rather, the term is defined in the NER. The AER has a role only in assessing applications for exemptions from the restricted assets provisions of the NER.

- classify distribution services in groups[26] – our general approach to service classification is to classify services in groupings rather than individually. This obviates the need to classify services one-by-one and instead defines a service cluster, that where a service is similar in nature it would require the same regulatory treatment. As a result, a new service with characteristics that are the same or essentially the same as other services within a group might simply be added to the existing grouping and hence be treated in the same way for ring-fencing purposes. This provides distributors with flexibility to alter the exact specification (but not the nature) of a service during a regulatory control period. Where we make a single classification for a group of services, it applies to each service in the group.
    - We are proposing that the pricing approach for any new services, introduced within the regulatory period – which clearly fall within one of the established service groupings – should be based on a similar service within that grouping. Rather than introducing new services at any time, DNSPs may notify us at the time of the annual price submission, regarding the new service and the price they plan to charge.
- In some circumstances, we may choose to classify a single service because of its particular nature. In addition, a distribution service that does not belong to any existing service classification may be 'not classified' and therefore be treated as an unregulated distribution service for that regulatory control period. New distribution services (that are created within a regulatory control period) are also to be treated as unregulated distribution services for the remainder of that regulatory control period.

Once we group services, the NER sets out a three-step classification process we must follow. We must consider a number of specified factors at each step. Figure 1.2 outlines the classification process under the NER.

Figure 1.2 Distribution service classification process



26 NER, cl. 6.2.1(b).

Source: NER, chapter 6, part B.

As illustrated by figure 2:

- We must first satisfy ourselves that a service is a 'distribution service' (step 1). The NER defines a distribution service as a service provided by means of, or in connection with, a distribution system.[27] A distribution system is a 'distribution network, together with the connection assets associated with the distribution network, which is connected to another transmission or distribution system'.[28]
- We then consider whether economic regulation of the service is necessary (step 2). When we do not consider economic regulation is warranted we will not classify the service. If economic regulation is necessary, we consider whether to classify the service as either a direct control or negotiated distribution service.
- When we consider that a service should be classified as direct control, we further classify it as either a standard control or alternative control service (step 3).

When deciding whether to classify services as either direct control or negotiated services, or to not classify them, the NER requires us to have regard to the 'form of regulation factors' set out in the NEL.[29] We have reproduced these at appendix A. They include the presence or extent of barriers to entry by alternative providers and whether distributors possess market power in provision of the services. The NER also requires us to consider the desirability of consistency in the form of regulation both within and beyond the jurisdiction.[30]

For services we intend to classify as direct control services, the NER requires us to have regard to a further range of factors.[31] These include the potential to develop competition in provision of a service and how our classification may influence that potential; whether the costs of providing the service are directly attributable to a specific person; and the possible effect of the classification on administrative costs.

Our classification decisions determine how distributors will recover the cost of providing services.[32] Distributors recover standard control service costs by averaging them across all customers using the shared network. This shared network charge forms the core distribution component of an electricity bill. In contrast, distributors will charge a specific user benefiting from an alternative control service. Alternative control classification is akin to a 'user-pays' system. We set service specific prices to enable the distributor to recover the full efficient cost of each service from the customers using that service. At a high level, a service will be classified as an alternative control service if it is either:

27 NER, chapter 10, glossary.

28 NER, chapter 10, glossary.

29 NER, cl. 6.2.1(c); NEL, s. 2F.

30 NER, cl. 6.2.1(c).

31 NER, cl. 6.2.2(c).

32 We regulate distributors by determining either the prices they may charge (price cap) or by determining the revenues they may recover from customers (revenue cap).

- potentially contestable, or
- it is a monopoly service used by a small number of identifiable customers on a discretionary or infrequent basis and the costs can be directly attributed to those customers.

For services we classify as negotiated, distributors and customers will negotiate service provision and price under a framework established by the NER. Our role is to arbitrate disputes where distributors and prospective customers cannot agree. Two instruments support the negotiation process (and form part of our distribution determination even where we do not classify any services as negotiated):

- Negotiating distribution service criteria—sets out the criteria distributors are to apply in negotiating the price, and terms and conditions, under which they supply distribution services. We will also apply the negotiating distribution service criteria in resolving disputes.
- Negotiating framework—sets out the procedures a distributor and any person wishing to use a negotiated distribution service must follow in negotiating for provision of the service.

In the case of some distribution services, we may determine there is sufficient competition that there is no need for us to classify the service as either a direct control or negotiated distribution service. That is, the market is sufficiently competitive, allowing customers to shop around for the best price. We refer to these distribution services as 'unregulated distribution services'. Broadly, pursuant to our Ring-Fencing Guideline, this means that while existing regulated distribution services will continue to be provided by the distributor, all unregulated distribution services or new services that come into existence within a regulatory control period must be provided outside of the regulated network business, unless it applies for, and receives, a waiver under the ring-fencing guideline.[33]

1.3 Reasons for AER's preliminary position

This section sets out our preliminary service classification and reasons for SA Power Networks' 2020−25 regulatory control period for:

- common distribution services (formerly 'network services')
- ancillary services
- metering services
- connection services
- public lighting services
- unregulated distribution services.

[33] AER, *Ring-fencing guideline electricity distribution*, October 2017; AER, *Electricity distribution ring-fencing guideline explanatory statement*, October 2017.

Appendix B contains a detailed table of our preliminary classification of SA Power Networks' distribution services.

1.3.1 Common distribution service

This service group was formerly called 'network services'. However, to avoid confusion with the defined terms in chapter 10 of the NER, we propose to rename this service group 'common distribution service'.

The Common distribution service grouping is a suite of activities concerned with providing a safe and reliable electricity supply to customers.[34] Activities within the common distribution service group are intrinsically tied to the network infrastructure and the systems that support the shared use of the distribution network by customers. Customers use or rely on access to common distribution service activities on a regular basis. Providing a common distribution service involves a variety of different activities, such as the construction and maintenance of poles and wires used to transport energy across the shared network. The precise nature of activities provided to plan, design, construct and maintain the shared network may change over time. Regardless of what activities make up the common distribution service, this service group reflects the provision of access to the shared network to customers.

Our preliminary position is to classify the grouping; common distribution service as a direct control service. SA Power Networks holds a licence to provide the activities within this service, which is the only distribution licence in place for South Australia.[35] Therefore, as the sole holder of the licence, SA Power Networks has an obligation to operate, maintain and protect its supply network. Only SA Power Networks can provide services that relate to the safe and reliable conveyance, and controlling the conveyance, of electricity through the distribution network. Further, consumers cannot source a common distribution service from other service providers. These arrangements create a regulatory barrier, preventing third parties from providing activities within the common distribution service group.[36] Therefore, we consider that there is no opportunity for third parties to enter the market for the provision of activities classified as a common distribution service.

We must further classify direct control services as either standard or alternative control services.[37] Our preliminary position is to retain the current standard control classification for the common distribution service grouping. There is no potential to develop competition in the market for the common distribution service grouping because of the barriers outlined above.[38] There would be no material effect on administrative costs for us, SA Power

34 NER, Chapter 10 glossary.

35 The licence is issued by the Essential Service Commission of South Australia. A copy of the licence is available on ESCOSA's website at www.escosa.sa.gov.au/electricity-overview/licensing/distribution-licences.aspx.

36 NER, cl. 6.2.1(c)(1); NEL, ss. 2F(a), (d) and (f).

37 NER, cl. 6.2.2(a).

38 NER, cl. 6.2.2(c)(1).

Networks, users or potential users by continuing this classification.[39] We currently classify the common distribution service grouping (or 'network services') in SA and all other NEM jurisdictions as standard control services.[40] Further, distributors provide activities listed within the common distribution service through a shared network and therefore cannot directly attribute the costs of these services to individual customers.[41]

SA Power Networks, in its request to replace the current F&A, supports our proposed classification of the common distribution service grouping as standard control services for the 2020−25 regulatory control period.[42]

We note that SA Power Networks has listed a new activity under the common distribution service heading, labelled "support for another distributor during an emergency event". This activity is provided in connection with a distribution system, and we consider it a distribution service. However, in the case of an emergency event, where the distributor is called upon to assist another distributor, the works performed are not on the distributor's shared network and the distributor is entitled to recover the costs of the assistance provided. While we propose to classify these activities as standard control, the distributor is still expected to seek recovery of the costs of the assistance provided. Going forward, we propose to adopt this approach across all NEM jurisdictions.

Emergency recoverable works

We define emergency recoverable works as the distributor's emergency work to repair damage following a person's act or omission, for which that person is liable (for example, repairs to a power pole following a motor vehicle accident).

Given that these services are provided in connection with a distribution system, we consider this a distribution service. In the current regulatory control period, we did not classify this service in South Australia. The service was, therefore, unregulated.[43] This was because the cost of these works could be recovered through other avenues (e.g. under common law). However, following the introduction of our Ring-fencing Guideline, we have had cause to consider the classification of this service. As an unregulated distribution service, it would be subject to ring-fencing, and could increase the cost of these activities. Instead, we intend these service should be classified as direct control.

Therefore, our preliminary position is for emergency recoverable works to be subsumed into the common distribution service group and classified as a direct control and standard control service. SA Power Networks supports this proposed approach.[44] Distributors are required to

39 NER, cll. 6.2.2(c)(2), (3).

40 NER, cl. 6.2.2(c)(4).

41 NER, cl. 6.2.2(c)(5).

42 SA Power Networks*, Request to replace framework and approach*, 31 October 2017, p. 6.

43 AER, Final framework and approach for QLD electricity distribution businesses, April 2014, p.37.

44 SA Power Networks - SA Power Networks' *letter: Request to replace framework and approach for 2020-25 determination*, 31 October 2017.

perform works to maintain or repair the shared network to ensure a safe and reliable electricity supply.

Although we propose classifying this service as a standard control service, a distributor is still expected to seek recovery of the cost of these emergency repairs from the third party where possible. If a distributor is successful in recovering the cost of the emergency repairs from a third party, this payment or revenue, would be netted off. This would prevent a distributor from recovering the cost of emergency repairs twice—as a standard control charge across the broader customer base and from the responsible third party. Going forward, we propose to adopt this approach across all NEM jurisdictions.

1.3.2 Metering services

All electricity customers have a meter that measures the amount of electricity they use.[45] On 26 November 2015, the AEMC made a final rule that opens up competition in metering services and give consumers more opportunities to access a wider range of metering services.[46]

The competitive framework is designed to promote innovation and lead to investment in advanced meters that deliver services valued by consumers at a price they are willing to pay. Improved access to the services enabled by advanced meters will provide consumers with opportunities to better understand and take control of their electricity consumption and the costs associated with their usage decisions.[47]

The final rule alters who has overall responsibility for the provision of metering services by providing for the role and responsibilities of the Responsible Person to be performed by a new type of Registered Participant − a Metering Coordinator. Any person can become a Metering Coordinator subject to satisfying certain registration requirements.[48]

Retailers are required to appoint the Metering Coordinator for their retail customers. The final rule also includes a number of other features to support the competitive framework for the provision of metering services, including consumer protections[49] and an ability for consumers to opt out of having an advanced meter installed if they have an existing, working meter.[50]

The new arrangements commenced on 1 December 2017 and required changes to the NER and the National Electricity Retail Rules (NERR).[51] Consequently, our proposed

45 All connections to the network must have a metering installation (NER, cl. 7.3.1A(a)).
46 AEMC, *Competition in metering services information sheet*, 26 November 2015.
47 AEMC, *Competition in metering services information sheet*, 26 November 2015.
48 AEMC, *Competition in metering services information sheet*, 26 November 2015.
49 AEMC, *Competition in metering services information sheet*, 26 November 2015.
50 AEMC, *Final rule to increase consumers' access to new services information sheet*, 26 November 2015.
51 AEMC, *Competition in metering services information sheet*, 26 November 2015.

classification of some metering services will also change for the 2020−25 regulatory control period.

Type 1 to 4 metering services

Type 1 to 4 meters provide a range of additional functions compared to other meters. In particular, these meter types have a remote communication ability. In South Australia, type 1 to 4 metering services are currently classified as negotiated distribution services. Again, this classification arises from our previous requirement to maintain the status quo. Further, stakeholder submissions have never called for us to reconsider the classification. However, type 1 to 4 meters are competitively available[52] and we do not currently regulate them in most other NEM jurisdictions—they are not classified and therefore are unregulated distribution services. This approach also overcomes any potential ring-fencing issues. Therefore, our preliminary position is not classify SA Power Networks' type 1 to 4 metering services so they become unregulated distribution services for the 2020−25 regulatory control period.

SA Power Networks supports our proposed approach to not classify type 1 to 4 metering services for the 2020−25 regulatory control period.[53]

Type 5 and 6 metering services

Up until 1 December 2017, SA Power Networks was the monopoly provider of type 5 (interval) and 6 (accumulation) meters[54]. However, from 1 December 2017 (and therefore before the commencement of the next regulatory control period on 1 July 2020), metering services across the National Energy Market (NEM)[55] became contestable. Therefore, since 1 December 2017, households and other small customers who traditionally use these meter types may elect to change their metering provider and the type of meter they have. Further, SA Power Networks (or any metering provider)[56] is no longer permitted to install or replace existing meters with type 5 or 6 meters (although SA Power Networks will continue to provide a number of other type 5 and 6 metering services to support the continued operation of existing type 5 and 6 meters). For this reason, new type 5 and 6 meter provision and new installation services are no longer permitted under the NER from 1 December 2017. Therefore our proposed position is to not classify these services for the 2020−25 regulatory control period.

However, SA Power Networks may still recover the capital cost of legacy type 5 and 6 metering equipment installed prior to 1 December 2017 as an alternative control service. Type 5 and 6 metering services were unbundled from standard control services in our final

52 NER, cll. 7.2.3(a)(2) and 7.3.1.A(a)).

53 SA Power Networks*, Request to replace framework and approach*, 31 October 2017, Appendix A, line item 16.

54 AER Final decision SA Power Networks distribution determination, Attachment 13, Classification of services - October 2015 p.16.

55 Except for the Northern Territory.

56 Except Power and Water Corporation in the NT, pursuant to chapter 7A NER (NT).

determination for 2015−20 regulatory control period[57] to promote customer choice and remove any classification barriers limiting contestable provision of these meters.[58] This approach aligned with AEMC's Power of Choice recommendations to unbundle metering costs from shared network charges.[59]

Type 7 metering services

Type 7 metering services are unmetered connections with a predictable energy consumption pattern (for example, public lighting connections). Such connections do not include a meter that measures electricity use. Charges associated with type 7 metering services relate to the process of estimating electricity use. For example, the distributor estimates public light usage using the total time the lights were on, the number of lights in operation and the light bulb wattage. SA Power Networks is the monopoly provider of type 7 metering services in SA.[60]

We therefore consider that there is no potential to develop competition in the provision of type 7 metering services.[61] We intend to classify type 7 metering services as direct control services and further, as standard control services. This is a continuation of the current classification of type 7 metering services.[62]

Ancillary services − Metering

SA Power Networks will be required to provide ancillary metering services to support the metering contestability framework along with metering services to support existing type 5 and 6 meters.

Some examples include:

- Type 5 and 6 meter final read − to conduct a final read on removed type 5 metering equipment as required by the Australian Energy Market Operator Service Level Procedure.[63]

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57 AER, *Final decision SA Power Networks determination 2015-16 to 2019-20, Attachment 13 Classification of services*, October 2015, p.. 13−10

58 AER, *Final decision ActewAGL 2015−19 regulatory control period, Attachment 13 Classification of services*, April 2015, pp. 13−11 to 13−15.

59 AEMC, *Consultation paper — National electricity amendment (expanding competition in metering and related services)*, April 2014.

60 NER, cl. 7.2.3(a)(2).

61 NER, cl. 6.2.2(c)(1).

62 AER Final decision SA Power Networks distribution determination, Attachment 13, Classification of services - October 2015 p.16.

63 This Service Level Procedures applies to Metering Providers who are accredited and registered by AEMO to provide metering services within the National Electricity Market (NEM). The Service Level Procedure details the technical requirements and performances associated with the provision, installation and maintenance of a metering installation. This Service Level Procedures is established under clause 7.14.1A of the NER for the various categories of registration and metering installation types as detailed under clause S7.4 of the NER.

- Distributor arranged outage for purposes of replacing meter − at the request of a retailer or metering coordinator, provide notification to affected customers and facilitate the disconnection/reconnection of customer metering installations where a retailer planned interruption cannot be conducted.[64]
- Type 5 and 6 meter recovery and disposal − at the request of the customer or their agent to remove a type 5 or 6 meter where a permanent disconnection has been requested.

A detailed list of metering services is contained in appendix B.

Our proposed classification and reasons for ancillary services (which captures ancillary metering services) are set out in section 1.3.4 below with our broader discussion on all ancillary services.

Metering coordinator, metering provider, metering data provider

Under the competitive framework for metering, the roles of metering coordinator, metering provider and metering data provider may be performed by any registered person.[65]

While we consider a metering coordinator, metering provider or metering data provider are distribution services, our proposed approach – with regard to new installations – is to not classify these services.[66] That is, we propose to treat them as unregulated distribution services. From a ring-fencing perspective, the provision of these services will need to be separated from the provision of direct control services if a distributor intends to enter the competitive metering market. We may consider ring-fencing waivers around office and staff sharing obligations where there are no third party competitors (for a time).[67]

Importantly, we consider that pre-existing type 5 and 6 metering services, as detailed in appendix B, already encompasses these roles and is reflected in the alternative control service charges.

To explain further, each distributor, as the current 'responsible person' under the NER, was appointed as the metering coordinator as at 1 December 2017.[68] The distributors will remain in this role until such time as their type 5 or 6 meter is replaced or they receive notice from a retailer that it is replacing them as metering coordinator. While a distributor acts as the initial

64 AEMC, *Rule determination, National Electricity Amendment (Expanding competition in metering and related services) Rule 2015; National Energy Retail Amendment (Expanding competition in metering and related services) Rule 2015*, 26 November 2015, p. 206.

65 AEMC, *Rule determination, National Electricity Amendment (Expanding competition in metering and related services) Rule 2015; National Energy Retail Amendment (Expanding competition in metering and related services) Rule 2015*, 26 November 2015, pp. 127−131.

66 NER, chapter 10, glossary; *Ergon Energy Corporation Ltd v Australian Energy Regulator* [2012] FCA 393

67 AER, *Ring-fencing guideline electricity distribution*, Version 2 October 2017; AER, *Electricity distribution ring-fencing guideline explanatory statement*, October 2017. CCP sub-panel 10 submitted that the AER should only grant short term waivers in relation to ring-fencing obligations, see: Consumer Challenge Panel (Sub-Panel 10), *Submission on AER's preliminary framework and approach for NSW DNSPs*, 21 April 2017, p. 9.

68 NER, cl. 11.86.7.

metering coordinator performing its current services like type 5 and 6 meter reading, maintenance and testing, we will classify it as an alternative control service. This approach avoids the need for distributors to incur costs ring-fencing the responsibilities of metering coordinator, when the instances of distributors performing this role will diminish as more type 5 and 6 meters are replaced or retailers exercise their ability to replace distributors as the metering coordinator.

1.3.3 Connection services

Put simply, a connection service refers to the services a distributor performs in order to:

- connect a person's home, business or other premises to the electricity distribution network (premises connection)
- get more electricity from the distribution network than is possible at the moment (augmentation);
- extend the network to reach a person's premises (extension).

In the current 2015−20 regulatory control period, SA Power Networks offers two types of connection services being basic and non-basic connections. A basic connection is a connection or an alteration which involves minimal or no augmentation (no extension or upgrade) of SA Power Networks' distribution network. This is different from non-basic connection services which require an augmentation. Basic connection services are currently classified as standard control services, while non-basic connection services are grouped under the non-standard network services group and are classified as negotiated services.[69]

Standard connection services

Our proposed approach is to maintain the classification for basic connections as direct control and further, as a standard control service for the 2020-25 regulatory period.[70]

Standard connection services are currently provided to the following groups of customers:

- residential customers (no extension or upgrade required)[71]
- small business customers up to a capacity of less than 63 amps per phase
- small embedded generators (e.g. customers who wish to install solar PV panels on their premises) with a generating capacity of up to 10kVA for a single phase connection and up to 30kVA for a three phase connection.

Similar to network services, SA Power Networks provides standard connection services on a 'standard' or routine basis. For example, a new residential property owner having their house connected to the network with minimal or no augmentation. This type of connection request

69 AER Final decision SA Power Networks distribution determination, Attachment 13, Classification of services - October 2015
70 AER Final decision SA Power Networks distribution determination, Attachment 13, Classification of services - October 2015
71 NER, chapter 5A, A1.

is common to anyone wanting to connect to the network to use electricity and therefore we consider that we should directly regulate the price of these services.

For the following reasons we consider the current standard control classification for standard connection services is appropriate:

- There is little, if any, prospect for competition in the market for standard connection services. That is, we are not aware of any South Australian Government initiatives to introduce contestability for connection services in the next regulatory control period. Therefore, our classification will not influence the potential for competition.
- There would be no material effect on administrative costs to us, SA Power Networks, users or potential users. This is because a standard control classification for standard connection services is consistent with the current regulatory approach.
- The nature of connection services is such that in most instances, the customer requesting the service will benefit from the provision of that service. As such, the costs are directly attributable to identifiable customers. To protect the broader customer base from incurring additional costs for services of no benefit to them, connections which require augmentation or significant alteration to the distribution network (as opposed to standard connection service where no such costs are required) require the requesting customer to make a capital contribution. This is discussed in the non-standard connection services section below.

For the above reasons, we consider retaining the current classification of standard control for standard connection services is justified.

Non-standard connection services

We propose to classify non-standard connection services as direct control and further, as an alternative control service for the 2020-25 regulatory period.

Non-standard connections are requested by customers at a higher standard than required (i.e. above the least cost technically acceptable solution). Examples include where a customer wants a permanent stand–by supply (e.g. back–up feeder or duplicate supply) or a higher voltage supply. Also in this category are: connections for large embedded generators which, given their size, require specific solutions and consideration of their impact on the network; and any other specific connection lines / assets that customers might request.

In the current 2015-20 regulatory control period, these services are classified as negotiated services.[72] This classification arose from the assessment that in most instances, non-standard connection services only benefit the customer requesting that service.

As previously indicated, the implementation of our Ring-fencing Guideline has caused DNSPs to reconsider the classification of many of the services they provide. SA Power

[72] AER, Final framework and approach for SA Power Networks regulatory 2015-20, April 2014, p. 24-25

Networks' has advised its preferred classification of these services is alternative control.[73] The rationale for this is that non-standard connection services reflect monopoly characteristics, as only the distributor can provide them, but that service-specific charges should be paid by customers that request them. We agree as we hold concerns about the ability of consumers to effectively negotiate the charges despite the existence of the negotiating framework. For most consumers, especially if services are demanded relatively rarely, the negotiation would be unlikely to deliver a balanced outcome. For this reason, these services are classified as alternative control in almost all other jurisdictions.

Our preliminary approach, therefore, is to classify non-standard connections as direct control and further as alternative control services. SA Power Networks holds the only electricity distribution licence to provide connection services in South Australia. This licensing arrangement results in a regulatory barrier preventing third parties from providing connection services.[74] Additionally, we consider the scale and scope of resources available to SA Power Networks also prevents the competitive provision of connection services by a third party. We therefore consider that SA Power Networks' possesses significant market power in the provision of connection services.[75]

Under an alternative standard control classification, SA Power Networks can recover costs from customers who request non-standard connections. However, we anticipate that most customers would only require standard connections. Chapter 5A of the NER and the Connection charge Guideline provides a framework and charging principles for new connections and connection alternations.[76] We are mindful of classifying SA Power Networks' connection services in a way that supports the operation of Chapter 5A and the Guideline. SA Power Networks is required to identify the circumstances in its Connection Policy where customer a charge may be applied to customer connections.[77]

On this basis we consider that classifying non-standard connections as alternative control services is the most appropriate classification for these services. We welcome submissions from stakeholders on this approach.

1.3.4 Ancillary services

We propose to classify ancillary services as direct control services for the 2010-25 regulatory control period. Further we intend to classify ancillary services as alternative control within the direct control classification.

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73 SA Power Networks - SA Power Networks' *letter: Request to replace framework and approach for 2020-25 determination*, 31 October 2017, p.7.

74 NEL, s. 2F(a).

75 NEL, s. 2F(d).

76 AER, *Connection charge guidelines for electricity retail customers, under Chapter 5A of the National Electricity Rules*, June 2012, p. 29

77 SA Power Networks is yet to submit its Connection Policy. Consequently, the classifications may be inconsistent with the Connection Policy. We will consider any such adjustments in our final F&A and if necessary, draft determination to avoid any inconsistencies.

Ancillary services share the common characteristics of being services provided to individual customers on an 'as needs' basis and the specific charge can be applied to the customer(s) requesting the service (e.g. meter testing and reading at a customer's request, moving mains, temporary supply, alteration and relocation of existing public lighting assets).

Ancillary services involve work on, or in relation to, parts of SA Power Networks' distribution network. Therefore, similar to common distribution services only SA Power Networks may perform these services in its distribution area. This proposed service group is new for SA Power Networks and captures many services which are currently classified as negotiated distribution services,

While the services included in the ancillary group may suit a negotiated distribution services framework by virtue of being specifically requested services that are tailored to customer requirements, these services also reflect monopoly characteristics. This creates a regulatory barrier preventing any party other SA Power Networks providing ancillary services in its distribution area.[78] Because of this monopoly position, customers may have limited negotiating power in determining the price and other terms and conditions on which SA Power Networks provides these services. These factors contribute to the view that SA Power Networks possesses significant market power in providing ancillary services.[79]

For these reasons, we consider that we should classify ancillary services as direct control services.

Further, we intend to classify ancillary services as alternative control services because SA Power Networks provides these services to specific customers.[80] As such, the cost of each ancillary service is directly attributable to an individual customer.[81] This results in costs that are more transparent for customers.

We adopt this view even though some ancillary services do not exhibit signs of competition or potential for competition. We do not consider that there would be any material effect on the administrative costs to us, the distributor, users or potential users of the network by reclassifying ancillary services from negotiated distribution services to alternative control services.[82] This is because we will set price caps on these services and the administrative and time costs to SA Power Networks and customers in negotiating the price of these services is removed.

To the extent that the provision of ancillary services become or may become contestable through future changes to the regulatory or contestability frameworks, our proposed alternative control classification would allow SA Power Networks to compete, as a discrete price for the service is set for each ancillary service.

78 NEL, s. 2F(a).
79 NEL, s. 2F.
80 NER, cl. 6.2.2(c)(5).
81 NER, cl. 6.2.2(c)(5) − this includes a small number of identifiable customers.
82 NER, cl. 6.2.2(c)(2).

1.3.5 Public lighting

Our preliminary approach is to classify public lighting services as alternative control services. This is a change from the current classification where public lighting is classified as a negotiated service.

SA Power Networks operates and maintains the majority of public lighting systems throughout SA. It provides these services on behalf of local councils and government departments responsible for public lighting in SA.

The NER does not define public lighting services. However, we have consistently defined public lighting services in other distribution determinations as:

- the operation, maintenance, repair and replacement of public lighting assets
- the alteration and relocation of public lighting assets, and
- the provision of new public lighting.[83]

While SA Power Networks does not have a legislative monopoly over these services, a monopoly position exists to some extent.[84] This is because SA Power Networks extensive network of poles is integral in the provision of public lighting services.[85] That is, other parties would need access to poles and easements for instance to hang their own public lighting assets. Therefore, similar to network services, ownership of network assets restricts the operation, maintenance, alteration or relocation of public lighting services to SA Power Networks.[86]Based on the above analysis, our preliminary position is to classify public lighting services, including emerging technology, as direct control services.[87]

As direct control services, we must further classify public lighting services as either standard control or alternative control services.[88] Our preliminary position is to classify public lighting as an alternative control service for the following reasons:

- classifying public lighting services as alternative control services provides scope for third parties and new entrants to provide public lighting services for new public lighting assets.[89]
- classifying public lighting services as alternative control services may encourage other potential service providers to enter the market in the future. In the meantime, an

83 See, for example, AER, *Final framework and approach for Queensland*, April 2014, p. 66; AER, *Final framework and approach for Victoria*, October 2014, p. 62.

87 NER, cl. 6.2.1.

88 NER, cl. 6.2.2(c).

89 NER, cl. 6.2.2(c)(1).

alternative control classification supports the National Electricity Objective by ensuring the distributor provides safe and reliable public lighting services to the community.[90]

- SA Power Networks can directly attribute the costs of providing public lighting services to a specific set of customers. This includes local councils and other government agencies.[91] An alternative control classification allows us to set price caps on these services. We consider that there would be any material effect on the administrative costs to us, the distributor, users or potential users of the network by reclassifying non-standard connections from negotiated distribution services to alternative control services.[92] This is because the administrative and time costs to SA Power Networks and customers in negotiating the price of these services are removed.
- Classifying public lighting services as alternative control is consistent with public lighting's current classification in other jurisdictions.[93]

For all the above reasons, we consider that there is a sufficient basis to reclassify public lighting services in SA as alternative control services.[94]

While SA Power Networks proposed reclassification of public lighting as an alternative control service, it has requested that we identify an approach within the classification framework that will provide some flexibility to tailor its service offering to its customers.

Under the negotiated distribution service classification, SA Power Networks negotiates with customers and charges for specific types of services—ranging from fully integrated services where they provide full luminaire and infrastructure maintenance and replacement of lights on their poles, to charges for maintenance of luminaires and systems management for lights on customer (i.e. council and State Government) owned infrastructure.

1.3.6 Unregulated distribution services

Unregulated distribution services is the term we us to describe distribution services which we have not classified as either direct control or negotiated services.[95] These services are provided on an unregulated basis and are potentially provided by other service providers in a competitive market. This group of services is particularly important as the number and types of services offered by distributors is growing and changing.

In October 2017, we published the amended Ring-Fencing Guideline for Electricity Distribution.[96] Our Ring-fencing Guideline interacts with a number of regulatory instruments,

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90 NER, cl. 6.2.2(c)(1).

91 NER, cl. 6.2.2(c)(5).

92 NER, cl. 6.2.2(c)(2).

93 See, for example, AER, *Final framework and approach for Queensland*, April 2014, p. 10; AER, *Final framework and approach for NSW*, July 2017, p. 35

94 NER, cl. 6.2.2(c)(3).

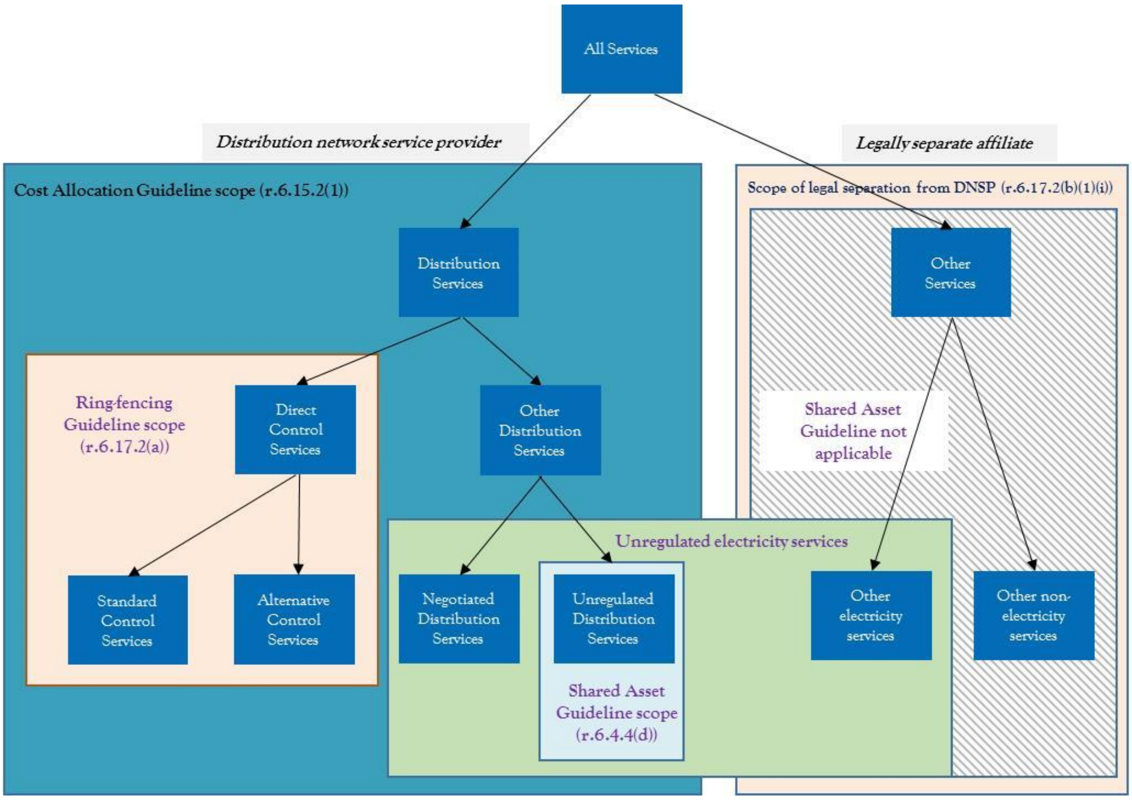
95 AER, *Electricity distribution ring-fencing guideline explanatory statement*, November 2016, p. 13.

96 AER, *Ring-fencing guideline electricity distribution*, Version 2 October 2017; AER, *Electricity distribution ring-fencing*

including our service classification decisions. Specifically, our service classification decisions set ring-fencing obligations for each distributor for its next regulatory control period.[97] Under our Ring-fencing Guideline, any unregulated distribution service would be protected by functional and accounting separation. This removes the potential risk of a distributor benefitting from its privileged access to network information to gain a competitive advantage.

Figure 1.3 illustrates the interrelationship between service classification and ring-fencing obligations. Essentially, a distributor may only provide distribution services. Affiliated entities may provide other electricity services. For the purposes of this preliminary F&A we are not addressing interactions with other regulatory frameworks in detail as these are set out in the explanatory statement to the ring-fencing guideline.[98]

Figure 1.3 Distribution services linkage to ring-fencing



Source: AER

In approaching classification of unregulated distribution services, distributors (and the AER) are considering if the service would be better offered by an affiliate and therefore not classified (i.e. fall into the 'other electricity services' group on the services diagram above).

guideline explanatory statement, October 2017.

97 AER, *Electricity distribution ring-fencing guideline explanatory statement*, November 2016, pp. 13−16.

98 AER, *Electricity distribution ring-fencing guideline explanatory statement*, November 2016, pp. 13−16.

Alternatively, some of these distribution services could be classified as alternative control services. As part of our distribution determination, we would set a cost-reflective price for the service based on information provided by the distributor. Customer uptake of the distributor provided service would depend on whether the price of the service is competitive with that of other market participants. It should be noted that if a service is classified as an alternative control service, it would not be subject to ring-fencing obligations, such as the requirements to use a different brand, to use separate offices and to not share staff. Consequently, there are market effects of classifying a potentially contestable service as an alternative control service rather than an unregulated service.

Developing a comprehensive list of unregulated distribution services will be challenging as this service group will capture all distribution services that are contestable services. This includes all contestable metering and contestable connection services.

Compliance with our ring-fencing guideline became mandatory on 1 January 2018. Distributors, when considering what unregulated distribution services they offer, should refer to the examples contained in the explanatory statement to the ring-fencing guideline[99] and their unregulated revenue streams. For example, a distributor may earn additional revenue from say NBN Co. by permitting NBN Co. to hang its wires from the same poles. The service is 'providing access to electricity poles'. Similarly, some other access to a network asset that forms part of the regulatory asset base (RAB) may be rented to a third party. The service for classification is 'access to a RAB asset'.

99 AER, *Electricity distribution ring-fencing guideline explanatory statement*, November 2016, Appendices A and B, pp. 77−86.

2 Forms of control

Our distribution determination must impose controls over the prices (and/or revenues) of direct control services.[100] This section sets out our preliminary position, together with our reasons, on the forms of control to apply to SA Power Networks' direct control services for the 2020–25 regulatory control period. This section also sets out our preliminary position on the formulae to give effect to these control mechanisms.

As discussed in chapter 1, we classify direct control services as standard control services or alternative control services. Different control mechanisms may apply to each of these classifications, or to different services within the same classification. Appendix B provides our preliminary classification of SA Power Networks' distribution services.

The form of control mechanisms in a distributor's regulatory proposal must be as set out in the relevant F&A paper.[101] Additionally, the formulae that give effect to the control mechanisms in a distributor's regulatory proposal must be the same as the formulae set out in the relevant F&A paper. The formulae cannot be altered unless we consider that there has been a material change in circumstances justify departing from the formulae set out in that paper.[102]

2.1 AER's preliminary position

Our preliminary position is to apply the following forms of control in the 2020–25 regulatory control period:

- Revenue cap — for services we classify as standard control services.
- Caps on the prices of individual services — for services we classify as alternative control services.

For standard control services, SA Power Networks has proposed the continuation of a revenue cap control mechanism over the 2020–25 regulatory control period.[103] SA Power Networks also suggested that the formula used to calculate the revenue cap in the most recent NSW, ACT, TAS and NT F&A papers appears to remain appropriate, subject to the clarification of customer contributions and the DMIS as outlined in its request to replace its current F&A.[104]

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100 NER, cl. 6.2.5(a).
101 NER, cl. 6.12.3(c).
102 NER, cl. 6.12.3(c1).
103 SA Power Networks - SA Power Networks' *letter: Request to replace framework and approach for 2020-25 determination*, 31 October 2017, p.9.
104 SA Power Networks - SA Power Networks' *letter: Request to replace framework and approach for 2020-25 determination*, 31 October 2017, pp.4,7 &17.

For alternative control services, SA Power Networks proposed the continuation of the price caps over the 2020–25 regulatory control period.[105] SA Power Networks are as yet undecided as to which form of control it considers appropriate for public lighting.[106]

2.2 AER's assessment approach

Our consideration of the control mechanisms for direct control services consists of three parts:

- the form of the control mechanisms[107]
- the formulae to give effect to the control mechanisms
- the basis of the control mechanism.[108]

The NER sets out the form of control mechanisms that may apply to both standard and alternative control services:[109]

- a schedule of fixed prices

A schedule of fixed prices specifies a price for every service provided by a distributor. The specified prices are escalated annually by inflation, the X factor and applicable adjustment factors. A distributor complies with the constraint by submitting prices matching the schedule in the first year and then escalated prices in subsequent years.

- caps on the prices of individual services (price caps)[110]

Caps on the prices of individual services are the same as a schedule of fixed prices except that a distributor may set prices below the specified prices.

- caps on the revenue to be derived from a particular combination of services (revenue cap)

A revenue cap sets total annual revenue (TAR) for each year of the regulatory control period. A distributor complies with the constraint by forecasting sales for the next regulatory year and setting prices so the expected revenue is equal to or less than the TAR. At the end of each regulatory year, the distributor reports its actual revenues to us. We account for differences between the actual revenue recovered and the TAR in future years. This operation occurs through an unders and overs account, whereby any revenue under recovery (over recovery) is added to (deducted from) the TAR in future years.

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105 SA Power Networks - SA Power Networks' *letter: Request to replace framework and approach for 2020-25 determination*, 31 October 2017, p.9

106 SA Power Networks - SA Power Networks' *letter: Request to replace framework and approach for 2020-25 determination*, 31 October 2017, p.9.

107 NER, cl. 6.2.5(b).

108 NER, cl. 6.2.6(a).

109 NER, cl. 6.2.5(b).

110 A price cap and a schedule of fixed prices are largely the same mechanism, with the only difference being that a price cap allows the distributors to charge below the capped price on some or all of the services.

- tariff basket price control (weighted average price cap or WAPC)

A WAPC is a cap on the average increase in prices from one year to the next. This allows prices for different services to adjust each year by different amounts. For example, some prices may rise while others fall, subject to the overall WAPC constraint. A weighted average is used to reflect that services may be sold in different quantities. Therefore, a small increase in the price of a frequently provided service must be offset by a large decrease in the price of an infrequently provided service. A distributor complies with the constraint by setting prices so the change in the weighted average price is equal to or less than the CPI–X cap. Importantly, the WAPC places no ceiling on the revenue recovered by a distributor in any given year. That is, if revenue recovered under the WAPC is greater than (less than) the expected revenue, the distributor keeps (loses) that additional (shortfall) revenue.

- revenue yield control (average revenue cap)

An average revenue cap is a cap on the average revenue per unit of electricity sold that a distributor can recover. The cap is calculated by dividing the TAR by a particular unit (or units) of output, usually kilowatt hours (kWh). The distributor complies with the constraint by setting prices so the average revenue is equal to or less than the TAR per unit of output.

- a combination of any of the above (hybrid).

A hybrid control mechanism is any combination of the above mechanisms. Typically, hybrid approaches involve a proportion of revenue that is fixed and a proportion that varies according to pre-determined parameters, such as peak demand.

In considering our preliminary position on the control mechanisms for SA Power Networks' standard control services, we have only considered the continuation of the revenue cap, or adoption of price caps or an average revenue cap. We have not considered the other forms of control mechanisms for standard control services based on our previous considerations that they are not superior to either an average revenue cap or a revenue cap in addressing the factors set out in clause 6.2.5(c) of the NER.

We have not considered a schedule of fixed prices. We consider direct price control mechanisms do not provide the level of flexibility within the regulatory control period to manage distribution use of service charges shared across the broad customer base.

We have not considered a WAPC as our previous considerations on this type of control mechanism noted the incentives for distributors to systematically recover revenue above efficient cost recovery resulting in higher bills for consumers.[111] We consider a control mechanism that results in higher bills for consumers than necessary is not consistent with the national electricity objective.[112]

111 For example, see: AER, *Final framework and approach for the Victorian electricity distributors: Regulatory control period commencing 1 January 2016*, 24 October 2014, p. 82 and AER, *Stage 1 Framework and approach, Ausgrid, Endeavour Energy and Essential Energy, 1 July 2014–30 June 2019*, March 2013, p. 78.

112 NEL, s. 7.

We have also not considered a hybrid approach as our previous deliberations considered the higher administrative costs outweigh the potential benefits of this form of control.[113]

However, we are open to consideration on these other control mechanisms for making our final F&A where stakeholders consider an alternative control mechanism for SA Power Networks' standard control services would best address the factors set out in clause 6.2.5(c) of the NER.

In considering our preliminary position on the control mechanisms for SA Power Networks' alternative control services, our consideration is based on whether there is reason to depart from the current price caps in terms of the factors set out in clause 6.2.5(c) of the NER.

2.2.1 Standard control services

In determining a control mechanism to apply to standard control services, we must have regard to the factors in clause 6.2.5(c) of the NER:

- need for efficient tariff structures
- possible effects of the control mechanism on administrative costs of us, the distributor, users or potential users
- regulatory arrangements (if any) applicable to the relevant service immediately before the commencement of the distribution determination
- desirability of consistency between regulatory arrangements for similar services (both within and beyond the relevant jurisdiction)
- any other relevant factor.

We also propose to have regard to three other factors which we consider are relevant to assessing the most suitable control mechanism:

- revenue recovery
- price flexibility and stability
- incentives for demand side management.

The basis of the control mechanism for standard control services must be of the prospective CPI–X form or some incentive-based variant.[114]

Section 2.3 sets out our consideration of each of the above factors in determining our preliminary position on the form of control mechanisms for standard control services.

2.2.2 Alternative control services

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113 For example, see: *AER, Final framework and approach for Victorian electricity distributors: Regulatory control period commencing 1 January 2016*, 24 October 2014, p. 86.

114 NER, cl. 6.2.6(a).

In determining a control mechanism to apply to alternative control services, we must have regard to the factors in clause 6.2.5(d) of the NER:

- the potential for competition to develop in the relevant market and how the control mechanism might influence that potential
- the possible effects of the control mechanism on administrative costs for us, the distributor and users or potential users
- the regulatory arrangements (if any) applicable to the relevant service immediately before the commencement of the distribution determination
- the desirability of consistency between regulatory arrangements for similar services (both within and beyond the relevant jurisdiction)
- any other relevant factor.

We propose that another relevant factor is the provision of cost reflective prices. Efficient prices (cost reflectivity) allow consumers to compare the cost of providing the service to their needs and wants. It also better promotes the national electricity objective by ensuring that customers only pay for services they use. Cost reflective prices also enable distributors to make efficient investment and demand side management decisions.

We must state what the basis of the control mechanism is in our distribution determination.[115] This may utilise elements of Part C of chapter 6 of the NER with or without modification. For example, the control mechanism may use a building block approach or incorporate a pass through mechanism.[116]

Section 2.4 sets out our consideration of each of the above factors in determining our preliminary position on the form of control mechanism for alternative control services.

2.3 AER's reasons — control mechanism and formulae for standard control services

Our decision is to maintain a revenue cap for SA Power Networks' standard control services for the 2020–25 regulatory control period. We consider the application of a revenue cap control mechanism best meets the factors set out under clause 6.2.5(c) of the NER.

A revenue cap will result in no additional administrative costs and allow for consistency of regulatory arrangements for standard control services both across regulatory periods and across jurisdictions.

A revenue cap will also result in benefits to consumers through a higher likelihood of revenue recovery at efficient costs and will provide better incentives for demand side management. Furthermore, our recent approach to the operation of the revenue cap has

115 NER, cl. 6.2.6(b).
116 NER, cl. 6.2.6(c).

reduced the magnitude of overall price variability during a regulatory control period, which has been a concern in the past. We provide our consideration of these issues below.

2.3.1 Efficient tariff structures

In deciding on a control mechanism, the NER requires us to have regard to the need for efficient tariff structures.[117] We consider tariff structures are efficient if they reflect the underlying cost of supplying distribution services.

It is likely that efficient tariff structures can be developed and implemented under all types of control mechanisms. Our recent assessment of distributors' tariff structures has demonstrated that efficient tariff structures have been developed and will be implemented under both average revenue cap and revenue cap control mechanisms.

Our previous considerations on the interaction between a control mechanism and its ability to deliver efficient tariff structures during a regulatory control period relied solely on the incentive properties of the different types of control mechanisms.[118] However, recent changes to the NER now require us to undertake a supplementary assessment of the efficiency of a distributor's tariff structures which are set out in a tariff structure statement. Therefore, consideration of the interaction between control mechanisms and efficient tariff structures should also be informed by our assessment of a distributor's tariff structure statement.

The requirement for distributors to prepare tariff structure statements is new. It arises from a significant process of reform to the NER governing distribution network pricing. The purpose of the reforms is to empower customers to make informed choices by:

- Providing better price signals—tariffs that reflect what it costs to use electricity at different times so that customers can make informed decisions to better manage their bills.
- Transitioning to greater cost reflectivity—requiring distributors to explicitly consider the impacts of tariff changes on customers, and engaging with customers, customer representatives and retailers in developing network tariff proposals over time.
- Managing future expectations—providing guidance for retailers, customers and suppliers of services such as local generation, batteries and demand management by setting out the distributor's tariff approaches for a set period of time.

A distributor's tariff structure statement sets out the tariff structures it can apply over a regulatory control period.[119] The tariff structure statement should show how a distributor

117 NER, cl. 6.2.5(c)(1).

118 For example, see: AER*, Final framework and approach for the Victorian electricity distributors: Regulatory control period commencing 1 January 2016*, 24 October 2014, pp. 79–81 and AER, *Stage 1 Framework and approach, Ausgrid, Endeavour Energy and Essential Energy, 1 July 2014–30 June 2019*, March 2013, pp. 76–77.

119 NER, cl. 6.18.1A(a)(3).

applied the distribution pricing principles[120] to develop its tariff structures and the indicative price levels of tariffs for the coming five year regulatory control period. The network pricing objective of the distribution pricing principles is the focus for a distributor when developing its network tariffs. The objective is that:[121]

> the tariffs that a distributor charges for provision of direct control services to a retail customer should reflect the distributor's efficient costs of providing those services to the retail customer.

We must approve a tariff structure statement unless we are reasonably satisfied it will not comply with the distribution pricing principles or other relevant requirements of the NER.[122]

In February 2017, we made final decisions on the initial tariff structure statements for SA Power Networks, ActewAGL and the distributors in Queensland and New South Wales. On 28 April 2017, we made our final decision on TasNetworks' initial tariff structure statement.

Through the initial tariff structure statements many distributors will be introducing more cost reflective tariff structures, such as demand based tariffs. In our assessment we found no evidence to suggest that ActewAGL's average revenue cap or other distributors' revenue caps inhibited the ability to develop or implement efficient tariff structures. Therefore, we consider that efficient tariff structures can occur under both average revenue cap and revenue cap control mechanisms. On this basis, we also consider efficient tariff structures are likely to occur under all forms of control mechanisms, including price caps.

While our consideration of efficient tariff structures does not necessarily indicate a revenue cap should be favoured over an average revenue cap or price caps, our decision needs to be weighed against the other factors under clause 6.2.5(c) of the NER.

We note that tariff reform brought about by the tariff structure statements is still in its infancy. We may revisit the interaction between a control mechanism and efficient tariff structures for future F&A's.

2.3.2 Administrative costs

In deciding on a control mechanism, the NER requires us to have regard to the possible effects of the control mechanism on administrative costs.[123] We consider, where possible, a control mechanism should minimise the complexity and administrative burden for us, the distributor and users.

Generally, we consider there is little difference in administrative costs between control mechanisms under the building block framework in the long run. However, we consider the

[120] This is a reference to the NER' *pricing principles for direct control services*, alternatively described in this paper as the "distribution pricing principles"; NER, cl. 6.18.5(e)–(j).

[121] NER, cl. 6.18.5(a).

[122] NER, cl. 6.12.3(k).

[123] NER, cl. 6.2.5(c)(2).

continuation of a revenue cap control mechanism to SA Power Networks' standard control services would have the least complexity and administrative burden. The continuation of a revenue cap would impose no additional administrative costs for us, SA Power Networks or users.

In contrast, additional administrative costs will be incurred by at least SA Power Networks and us in transitioning from a revenue cap to a price cap or alternative form of control mechanism. For example, new tariff models would need to be developed for annual pricing proposals to demonstrate compliance with the new control mechanism. Therefore, we consider the continuation of a revenue cap is superior in meeting clause 6.2.5(c)(2) of the NER.

2.3.3 Existing regulatory arrangements

In deciding on a control mechanism, the NER requires us to have regard to the regulatory arrangements applicable to the relevant service immediately before the commencement of the distribution determination.[124] We note maintaining a revenue cap control mechanism for SA Power Networks' standard control services provides for consistent regulatory arrangements for these services across regulatory control periods. Therefore, we consider the continuation of a revenue cap control mechanism is superior in meeting clause 6.2.5(c)(3) of the NER than an alternative control mechanism.

2.3.4 Desirability of consistency between regulatory arrangements

In deciding on a control mechanism, the NER requires us to have regard to the desirability of consistency between regulatory arrangements for similar services both within and beyond the relevant jurisdiction.[125] We consider the continuation of a revenue cap control mechanism for SA Power Networks' standard control services delivers consistent regulatory arrangements for these services across jurisdictions.

Apart from ActewAGL, all other electricity distributors' who are currently subject to economic regulation under the NER have a revenue cap control mechanism applied to their standard control services. However, we have decided to apply a revenue cap to ActewAGL's standard control services for the 2019–24 regulatory control period,[126] This means that from 1 July 2019 all distributors' standard control services will be subject to a revenue cap control mechanism. Therefore maintaining SA Power Networks' revenue cap control mechanism will ensure consistent regulatory arrangements for these services across jurisdictions. For these reasons, we consider the continuation of a revenue cap control mechanism is superior in meeting clause 6.2.5(c)(4) of the NER than an alternative mechanism.

124 NER, cl. 6.2.5(c)(3).

125 NER, cl. 6.2.5(c)(4).

126 ActewAGL Distribution, *Response to AER preliminary framework and approach*, April 2017, p. 11.

2.3.5 Revenue recovery

We consider that a control mechanism should give a distributor an opportunity to recover efficient costs. Also, a control mechanism should limit revenue recovery above such costs. Revenue recovery above efficient costs results in higher prices for end users. Further, allocative efficiency is reduced when a distributor recovers additional revenue from price sensitive services through prices above marginal cost.[127]

Generally, we consider that a revenue cap provides a high likelihood of efficient cost recovery. Under a revenue cap, revenue recovery is fixed and unrelated to energy sales. Similarly, costs for distributors are largely fixed and unrelated to energy sales. Therefore, our view is that a revenue cap is likely to lead to efficient cost recovery.

We also consider that a revenue cap incentivises distributors to reduce their expenditures because their revenues are assured during the regulatory control period. These lower costs can be shared with customers in future regulatory control periods.

In contrast, control mechanisms where revenue depends on energy sales (such as average revenue caps or price caps) provides distributors with incentives to understate sales forecasts and adjust tariffs to gain revenues above efficient cost levels.[128] A systematic recovery of revenue above efficient cost recovery results in higher bills for consumers.[129] We consider a control mechanism that results in higher bills for consumers than necessary is not consistent with the national electricity objective.[130]

In terms of efficient revenue recovery, we consider a revenue cap control mechanism better reflects the national electricity objective than those that rely on energy sales.[131]

2.3.6 Pricing flexibility and stability

Price flexibility enables a distributor to restructure its tariffs to meet changes in the environment of operating an electricity distribution network during a regulatory control period. Price stability is important because it affects retailers' ability to manage risks incurred from changes to network tariffs, which they then package into retail plans for customers. It also affects customers' ability to manage their bills.

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127 Allocative efficiency is achieved when the value consumers place on a good or service (reflected in the price they are willing to pay) equals the cost of the resources used up in production. The condition required is that price equals marginal cost. When this condition is satisfied, total economic welfare is maximised.

128 For example, see: *AER, Preliminary positions: Framework and approach paper ActewAGL—Regulatory control period commencing 1 July 201*4, pp. 64–67; AER,

129 For example, see: AER, *Final framework and approach for the Victorian electricity distributors: Regulatory control period commencing 1 January 2016*, 24 October 2014, p. 82 and AER, *Stage 1 Framework and approach, Ausgrid, Endeavour Energy and Essential Energy, 1 July 2014–30 June 2019*, March 2013, p. 78.

130 NEL, s. 7.

131 NEL, s. 7.

We consider price flexibility is primarily influenced by the distribution pricing principles and the side constraint. Therefore, price flexibility is similar for all control mechanisms as they are subject to the same distribution pricing principles and the same side constraint.

In terms of price stability, some control mechanisms are more likely to deliver stable prices than others. However, price instability can occur under all control mechanisms because the NER require various annual price adjustments regardless of the control mechanism.[132]

Within a regulatory control period, an average revenue cap or price caps will deliver more overall price stability than a revenue cap. The increased variability under a revenue cap occurs because future revenues and tariffs are adjusted to account for the difference between the actual revenue recovered and the TAR. These differences are due to the variations between forecast and actual sales volumes. The true up of this under or over recovery of revenue is calculated in the unders and overs account.

Typically there is a two year lag from when the under or over recovery of revenue occurs (year t–2) and the year in which audited accounts can be relied upon to make an accurate revenue true up adjustment (year t). This lagged effect may cause price instability when an under (over) recovery of revenue in one year is followed by an over (under) recovery in the following year. In this scenario, price movements go in one direction for first year and then go in the opposite direction the following year.

We have somewhat addressed this issue in our recent determinations by applying a rolling unders and overs account which includes an additional true up for the estimated under and over recovery of revenues for the year in between (year t–1).[133] The inclusion of this estimated year helps smooth year-on-year revenue and tariff adjustments because the effects of the estimated year t–1 under or over recovery will have been largely accounted for when year t–1 becomes year t–2. That is, when year t–1 becomes year t–2 the adjustment to the TAR will only need to account for the difference between the estimated and actual under or over recovery and not the overall total under or over recovery.

In terms of stability across regulatory control periods, we consider an average revenue cap can result in greater price volatility compared to a revenue cap.[134] This issue is particularly pronounced if a trend of falling demand and consumption has set in throughout the regulatory control period. This scenario would prompt a large upward adjustment in the X-factors (and hence prices) for the next regulatory control period under an average revenue cap. In contrast, the volume forecasts are updated annually under a revenue cap. This would mean that prices would rise gradually over the regulatory period (rather than jump up at the end of the period) if a trend of falling demand was evident.

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132 These include cost pass throughs, jurisdictional scheme obligations, tribunal decisions and transmission prices passed on to the distributors from transmission network service providers.

133 For example, see: AER, *Final Decision, CitiPower distribution determination 2016 to 2020: Attachment 14–Control mechanisms*, May 2016, Appendix A, pp. 18–19.

134 AER, *Preliminary positions: Framework and approach paper ActewAGL—Regulatory control period commencing 1 July 2014*, pp. 67–69.

On balance, when weighing price flexibility and stability along with the other factors we have considered, our preliminary position is to maintain SA Power Networks' revenue cap control mechanism for standard control services. While we acknowledge a revenue cap has a higher likelihood of overall price instability during a regulatory control period, we consider our application of the rolling unders and overs account reduces the magnitude of this effect.

2.3.7 Incentives for demand side management

Demand side management refers to the implementation of non-network solutions to avoid the need to build network infrastructure to meet increases in annual or peak demand.[135] Where prices are cost reflective, consumers and providers of demand side management face efficient incentives because they can take into account the cost of providing the service in decision making.

Under a revenue cap a distributor's revenue is fixed over the regulatory control period. A distributor can therefore improve its financial position by reducing costs. This creates an incentive for a distributor to undertake demand side management projects that reduce total costs, even if that means the distributor does not build new assets or replace existing ones.[136] We consider this provides a stronger incentive for a distributor to undertake demand side management within a regulatory control period compared to a control mechanism that has expected revenues varying with overall sales, such as in a price cap.

Under an average revenue cap or price cap control mechanism, a distributor's revenues are linked more closely to actual volumes of electricity distributed. As a result, distributors' profits increase with sales if the marginal revenue is greater than the marginal cost of providing services. Demand side management may not be attractive for distributors if such projects result in less revenue as a result on the decline in demand or consumption that they induce.

2.3.8 Formulae for control mechanism

We are required to set out our proposed approach to the formulae that give effect to the control mechanisms for standard control services in the F&A paper.[137] In making a distribution determination, the formulae must be as set out in our final F&A, unless we consider that unforeseen circumstances justify departing from the formulae as set out in the F&A paper.[138] Below is proposed formula to apply to SA Power Networks' standard control services revenues. We consider that the formula gives effect to the revenue cap.

135 Generally peak demand is referred to as the maximum load on a section of the network over a very short time period.

136 That is, demand side management projects that result in a reduction in future network expenditure greater than the cost of implementing the demand side management projects.

137 NER, cl. 6.8.1(b)(2)(ii).

138 NER, cl. 6.12.3(c1).

Figure 2.1 Preliminary position revenue cap to be applied to SA Power Networks' standard control services

1. $TAR_t \geq \sum_{i=1}^{n} \sum_{j=1}^{m} p_t^{ij} q_t^{ij}$ i = 1,…,n and j = 1,…,m and t = 1, 2…,5

2. $TAR_t = AAR_t + I_t + B_t + C_t$ t = 1, 2...,5

3. $AAR_t = AR_t \times (1 + S_t)$ t = 1

4. $AAR_t = AAR_{t-1} \times (1 + \Delta CPI_t) \times (1 - X_t) \times (1 + S_t)$ t = 2,…,5

where:

TAR_t is the total allowable revenue in year t.

p_t^{ij} is the price of component 'j' of tariff 'i' in year t.

q_t^{ij} is the forecast quantity of component 'j' of tariff 'i' in year t.

t is the regulatory year.

AR_t is the annual smoothed revenue requirement in the Post Tax Revenue Model (PTRM) for year t.

AAR_t is the adjusted annual smoothed revenue requirement for year t.

I_t is the sum of incentive scheme adjustments in year t. To be decided in the distribution determination.

B_t is the sum of annual adjustment factors in year t. Likely to incorporate but not limited to adjustments for the unders and overs account. To be decided in the distribution determination.

C_t is the sum of approved cost pass through amounts (positive or negative) with respect to regulatory year t, as determined by the AER. It will also include any end-of-period adjustments in year t. To be decided in the distribution determination.

S_t is the s-factor for regulatory year t.[139] As it currently stands, the s-factor will incorporate any adjustments required due to the application of the AER's STPIS.[140]

139 The meaning for year “t” under the price control formula is different to that in Appendix C of STPIS. Year “t+1” in

However, we are currently undertaking a review of the STPIS. How the s-factor will apply within the revenue cap formula may depart from the current arrangements. Depending on the outcome of our review, provision to adjust revenues for performance against the STPIS may be made through either the *S* or *I* factors as set out in this preliminary F&A paper. If the review is completed in time, the distributors may need to apply the revised STPIS for the 2020–25 regulatory control period. We will consider the application of the revised STPIS during the revenue determination process.

ΔCPI_t is the annual percentage change in the ABS CPI All Groups, Weighted Average of Eight Capital Cities[141] from the December quarter in year t–2 to the December quarter in year t–1, calculated using the following method:

> The ABS CPI All Groups, Weighted Average of Eight Capital Cities for the December quarter in regulatory year t–1
>
> divided by
>
> The ABS CPI All Groups, Weighted Average of Eight Capital Cities for the December quarter in regulatory year t–2
>
> minus one.

For example, for 2020–21, year t–2 is the December quarter 2018 and year t–1 is the December quarter 2019.

X_t is the X-factor in year t, incorporating annual adjustments to the PTRM for the trailing cost of debt where necessary. To be decided in the distribution determination.

2.4 AER's reasons — control mechanism for alternative control services

Our preliminary position is to apply caps on the prices of individual services (price caps) in the 2020–25 regulatory control period to all of SA Power Networks' alternative control services. We propose classifying the following services as alternative control services:

- type 5 and 6 metering services (legacy metering services)
- public lighting services
- non-standard connection services
- ancillary services.

Appendix C of STPIS is equivalent to year "t" in the price control formula of this decision.

140 AER, *Electricity distribution network service providers - service target performance incentive scheme*, 1 November 2009.

141 If the ABS does not or ceases to publish the index, then CPI will mean an index which the AER considers is the best available alternative index.

We note SA Power Networks' alternative control services are currently subject to price cap regulation. The continuation of these price caps over the 2020–25 regulatory control period best meets the factors set out under clause 6.2.5(d) of the NER.

Unlike standard control services, the NER is not prescriptive on the basis of the control mechanism for alternative control services.[142] For example, the price caps could be based on a building block approach, or a modified building block cost build up. We have set out our proposed formulae that will give effect to the price cap control mechanisms in figure 2.2 and figure 2.3 below. However, it is at the distributor's discretion as to the approach it undertakes to develop its initial prices.

Prices for certain ancillary services will be determined on a quoted basis. Prices for quoted services are based on quantities of labour and materials with the quantities dependent on a particular task. For example, where a customer seeks a non-standard connection which may involve an extension to the network the distributor may only be able to quote on the service once it knows the scope of the work. Because of this uncertainty, our preliminary position price cap formula for quoted services differs to that proposed to apply to metering and fee based services. Our quoted services price cap is consistent with the approach we have adopted in the past.

A further consideration relates to the treatment of new services that might be offered by SA Power Networks within the regulatory control period. Where such services were not identified at the time of the AER Determination but for which the service clearly falls within one of the established service groupings, we propose that a quoted price approach be adopted based on a similar service within that same service grouping. For example, the price for a new type of security lighting would be set based on the same approach as a similar security lighting service. This approach would give SA Power Networks additional flexibility to introduce new services while offering consumers the protections associated with price regulation. If there was no other similar service, the new service would be unregulated and may therefore be subject to ring-fencing restrictions that affect use of the SA Power Network's brand and sharing of staff and offices in offering the new services.

Application for the introduction of a new ACS service, within the regulatory control period, is to be made at the time of the annual price submission. The application should provide a detailed description of the service to be introduced along with a plan for how the new service will be charged.

Our preliminary consideration of the relevant factors is set out below.

2.4.1 Influence on the potential to develop competition

We consider a departure from the current price cap controls for SA Power Networks' alternative control services would not have a significant impact on the potential development

142 NER, cl. 6.2.6(c).

of competition. We consider the primary influence on competition development will be the classification of services as alternative control services. Chapter 1 discusses service classification.

2.4.2 Administrative costs

Where possible, a control mechanism should minimise the complexity and administrative burden for us, the distributor and users. The continuation of price caps will impose no additional administrative costs for us, SA Power Networks or users. Additional administrative costs will be incurred at least to SA Power Networks and us if an alternative control mechanism was applied to these services.

2.4.3 Existing regulatory arrangements

We consider consistency across regulatory control periods is generally desirable. Our preliminary position maintains this regulatory consistency as it continues the application of price cap control mechanisms for SA Power Networks' alternative control services.

2.4.4 Desirability of consistency between regulatory arrangements

We consider consistency across jurisdictions is also generally desirable. Our preliminary position maintains this consistency across jurisdictions.

We note that apart from the Victorian distributor's metering services which are subject to a revenue cap, price cap control mechanisms are currently applied to the alternative control services for all other electricity distributors subject to economic regulation under the NER.

2.4.5 Cost reflective prices

We consider that price caps are more suitable than other control mechanisms for delivering cost reflective prices. To apply price caps to the prices, we estimate the cost of providing each service and set the price at that cost. This will enhance cost reflectivity on both competitive and non-competitive services.

2.4.6 Formulae for alternative control services

We are required to set out our proposed approach to the formulae that gives effect to the control mechanisms for alternative control services.[143] In making a distribution determination, the formulae must be as set out in our final F&A, unless we consider that unforeseen circumstances justify departing from the formulae as set out in the F&A paper.[144]

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143 NER, cl. 6.8.1(b)(2)(ii).
144 NER, cl. 6.12.3(c1).

Below are our preliminary price cap formulae which will apply to SA Power Networks' alternative control services.

Figure 2.2 Preliminary price cap formula to be applied to SA Power Networks' legacy metering, public lighting and ancillary services (fee based)

$\bar{p}_t^i \geq p_t^i$ i=1,...,n and t=1, 2,…,5

$$\bar{p}_t^i = \bar{p}_{t-1}^i \times (1 + \Delta CPI_t) \times (1 - X_t^i) + A_t^i$$

Where:

$\bar{p}_t^i$ is the cap on the price of service i in year t.

p_t^i is the price of service i in year t. The initial value is to be decided in the distribution determination.

$\bar{p}_{t-1}^i$ is the cap on the price of service i in year t–1.

t is the regulatory year.

ΔCPI_t is the annual percentage change in the ABS consumer price index (CPI) All Groups, Weighted Average of Eight Capital Cities[145] from the December quarter in year t–2 to the December quarter in year t–1, calculated using the following method:

> The ABS CPI All Groups, Weighted Average of Eight Capital Cities for the December quarter in regulatory year t–1
>
> divided by
>
> The ABS CPI All Groups, Weighted Average of Eight Capital Cities for the December quarter in regulatory year t–2
>
> minus one.

For example, for 2020–21, year t–2 is the December quarter 2018 and year t–1 is the December quarter 2019.

X_t^i is the X factor for service i in year t. The X factors are to be decided in the distribution determination and will be based on the approach the distributor undertakes to develop its initial prices.

145 If the ABS does not, or ceases to, publish the index, then CPI will mean an index which the AER considers is the best available alternative index.

A_t^i is the sum of any adjustments for service i in year t. Likely to include, but not limited to adjustments for any approved cost pass through amounts (positive or negative) with respect to regulatory year t, as determined by the AER.

Figure 2.3 Preliminary price cap formula to be applied to SA Power Networks' quoted services

$$Price = Labour + Contractor\ Services + Materials$$

Where:

$Labour$ consists of all labour costs directly incurred in the provision of the service which may include labour on-costs, fleet on-costs and overheads. Labour is escalated annually by $(1 + \Delta CPI_t)(1 - X_t^i)$ where:

ΔCPI_t is the annual percentage change in the ABS CPI All Groups, Weighted Average of Eight Capital Cities[146] from the December quarter in year t–2 to the December quarter in year t–1, calculated using the following method:

> The ABS CPI All Groups, Weighted Average of Eight Capital Cities for the December quarter in regulatory year t–1
>
> divided by
>
> The ABS CPI All Groups, Weighted Average of Eight Capital Cities for the December quarter in regulatory year t–2
>
> minus one.

For example, for 2020–21, year t–2 is the December quarter 2018 and year t–1 is the December quarter 2019.

X_t^i is the X factor for service i in year t. The X factor is to be decided in the distribution determination and will be based on the approach the distributor undertakes to develop its initial prices.

$Contractor\ Services$ reflect all costs associated with the use of external labour including overheads and any direct costs incurred. The contracted services charge applies the rates under existing contractual arrangements. Direct costs incurred are passed on to the customer.

$Materials$ reflect the cost of materials directly incurred in the provision of the service, material storage and logistics on-costs and overheads.

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146 If the ABS does not, or ceases to, publish the index, then CPI will mean an index which the AER considers is the best available alternative index.

3 Incentive schemes

This chapter sets out our preliminary position on the application of a range of incentive schemes to SA Power Networks for the 2020−25 regulatory control period. At a high level, our preliminary position is to apply the:

- service target performance incentive scheme
- efficiency benefit sharing scheme
- capital expenditure sharing scheme
- demand management incentive scheme and innovation allowance mechanism.

3.1 Service target performance incentive scheme

This section sets out our proposed approach and reasons for applying the service target performance incentive scheme (STPIS) to SA Power Networks in the next regulatory control period.

Our distribution STPIS[147] provides a financial incentive to distributors to maintain and improve service performance. The scheme aims to ensure that cost efficiencies incentivised under our expenditure schemes do not arise through the deterioration of service quality for customers. Penalties and rewards under the STPIS are calibrated with how willing customers are to pay for improved service. This aligns the distributor's incentives towards efficient price and non-price outcomes with the long-term interests of consumers, consistent with the National Electricity Objective (NEO).

The STPIS operates as part of the building block determination and contains two mechanisms:

- The service standards factor (s-factor) adjustment to the annual revenue allowance for standard control services rewards (or penalises) distributors for improved (or diminished) service compared to predetermined targets. Targets relate to service parameters pertaining to reliability and quality of supply, and customer service.
- A guaranteed service level (GSL) component composed of direct payments to customers[148] experiencing service below a predetermined level. This component only applies if there is not another GSL scheme already in place.[149]

147 AER, *Electricity distribution network service providers - service target performance incentive scheme*, 1 November 2009.

148 Except where a jurisdictional electricity GSL requirement applies.

149 Service level is assessed (unless we determine otherwise) with respect to parameters pertaining to the frequency and duration of interruptions; and time taken for streetlight repair, new connections and publication of notices for planned interruptions.

While the mechanics of how the STPIS will operate are outlined in our scheme, we must set out key aspects specific to SA Power Networks in the next regulatory control period at the determination stage, including:

- the maximum revenue at risk under the STPIS
- how the distributors' networks will be segmented or the purpose of setting performance targets
- the applicable parameters for the s-factor adjustment of annual revenue
- performance targets for the applicable parameters in each network segment
- the criteria for certain events to be excluded from the calculation of annual performance and performance targets
- incentive rates that determine the penalties and rewards under the scheme.

SA Power Networks may propose to vary the application of the STPIS in its regulatory proposal.[150] We can accept or reject the proposed variation in our determination. Each year we will calculate SA Power Networks s-factor based on service performance in the previous year against targets, subject to the revenue at risk limit. Our national STPIS includes a banking mechanism, allowing distributors to propose delaying a portion of the revenue increment or decrement for one year to limit price volatility for customers.[151] A distributor proposing a delay must provide in writing its reasons and justification as to why a delay will result in reduced price variations to customers.

Our STPIS currently applies to SA Power Networks. The 2015−20 regulatory control period was the first time that SA Power Networks was subject to the national scheme, The level of financial risk to SA Power Networks in terms of penalty or reward was set at ±5 per cent of the allowable revenue.[152] GSLs are provided for through the Essential Services Commission of South Australia's GSL scheme, so the GSL component of our scheme does not apply.

3.1.1 AER's preliminary position

Our preliminary position is to continue to apply the current version of the national STPIS to SA Power Networks in the 2020−25 regulatory control period. We propose to:

- set revenue at risk within the range of ±5 per cent
- segment the network according to the four STPIS feeder categories (CBD, urban, short rural and long rural) as per the scheme's definitions

[150] AER, *Electricity distribution network service providers – service target performance incentive scheme*, 1 November 2009, cl. 2.2.

[151] AER, *Electricity distribution network service providers – service target performance incentive scheme*, 1 November 2009, cll. 2.5(d) and (e).

[152] AER, Final decision, South Australia distribution determination, Attachment 11, STPIS, October 2015, p. 6.

- apply the system average interruption duration index or SAIDI, system average interruption frequency index or SAIFI and customer service (telephone answering) parameters
- set performance targets based on the distributor's average performance over the past five regulatory years
- apply the method in the STPIS for excluding specific events from the calculation of annual performance and performance targets
- apply the method and value of customer reliability (VCR) values as indicated in AEMO's 2014 Value of Customer Reliability Review final report.

We will not apply the GSL component if SA Power Networks remains subject to a jurisdictional GSL scheme.

We are currently undertaking a review of the STPIS. If the review is completed in time, SA Power Networks may need to apply the revised STPIS for the 2020–25 regulatory control period. SA Power Networks has indicated in it request to replace the current F&A that we should apply the revised STPIS.[153] We will consider the application of the revised STPIS during the revenue determination process.

3.1.2 AER's assessment approach

In deciding how to apply the current STPIS we have considered the requirements of the NER. The NER sets out certain requirements in relation to developing and implementing a STPIS.[154] These include:

Jurisdictional obligations

- consulting with the authorities responsible for the administration of relevant jurisdictional electricity legislation
- ensuring that service standards and service targets (including GSL) set by the scheme do not put at risk the distributor's ability to comply with relevant service standards and service targets (including GSL) specified in jurisdictional electricity legislation any regulatory obligations or requirements to which the distributor is subject.

Benefits to consumers

- We must take into account the benefits to consumers of applying the STPIS. This includes: the need to ensure that benefits to consumers likely to result from the scheme are sufficient to warrant any penalty or reward under the scheme
- the willingness of the customer or end user to pay for improved performance in the delivery of services

153 SA Power Networks, *Request to replace the framework and approach*, 31 October 2017, p. 3.
154 NER, cl. 6.6.2(b).

- balanced incentives
- the past performance of the distribution network
- any other incentives available to the distributor under the NER or the relevant distribution determination
- the need to ensure that the incentives are sufficient to offset any financial incentives the distributor may have to reduce costs at the expense of service levels
- the possible effects of the schemes on incentives for the implementation of non-network alternatives.

We considered the benefits to consumers of applying the STPIS when we developed the scheme. These considerations are set out in our final decision for the distribution STPIS.[155]

3.1.3 Reasons for AER's preliminary position

Our reasons for applying the STPIS to SA Power Networks in the next regulatory control period are set out below.

Jurisdictional obligations

In South Australia, the Essential Service Commission of South Australia (ESCOSA) administers and monitors compliance with the distribution licence conditions. As required by the rules, we will consult with the ESCOSA and the Department for Manufacturing, Innovation, Trade, Resources and Energy, as jurisdictional authorities, on the implementation of the STPIS[156] before finalising our distribution determination.

Our proposed approach to applying the STPIS for SA Power Networks does not intend to compromise SA Power Networks ability to comply with jurisdictional licence obligations or create duplication. We intend doing this by not:

- setting service performance targets lower than the minimum service requirements in the licence conditions; and
- applying the GSL component of our national STPIS while ESCOSA's guaranteed customer service arrangements remain in place.

Benefits to consumers

We are mindful of the potential impact of the STPIS on consumers. Under the NER, we must consider customers' willingness to pay for improved service performance so benefits to consumers are sufficient to warrant any penalty or reward under the STPIS.[157]

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155 AER, *Final decision: Electricity distribution network service providers Service target performance incentive scheme*, 1 November 2009.

156 NER, cl. 6.6.2(b)(1).

157 NER, cl. 6.6.2(b)(3)(vi).

Under the STPIS, a distributor's financial penalty or reward in each year of the regulatory control period is the change in its annual revenue allowance after the s-factor adjustment. Economic analysis of the value consumers place on improved service performance is an important input to the administration of the scheme. Value of customer reliability (VCR) studies estimate how willing customers are to pay for improved service reliability as a monetary amount per unit of unserved energy during a supply interruption.

The VCR estimates currently in our national STPIS are taken from studies conducted for the Essential Services Commission Victoria and Essential Services Commission of South Australia.[158]

In September 2014 AEMO completed analysis of the VCR across the NEM.[159] We stated in our final decision for NSW distributors' 2015–19 regulatory period and our preliminary F&A for NSW distributors' 2019−24 regulatory period,[160] that we will apply the latest value for VCR through the distribution determination in calculating the incentive rates. This is because we consider the 2014 AEMO NSW and ACT VCR better reflects the willingness of customers to pay for the reliable supply of electricity in SA. We consider that this approach is still appropriate.

Incentive rates will be calculated at the commencement of the regulatory control period (in the distribution determination) and will apply for the duration of the regulatory control period.

Our proposed approach is to apply the scheme standard level of revenue at risk for SA Power Networks at ± 5 per cent as we do not consider that a lower level would better meet the objectives of the STPIS.

Balanced incentives

We administer our incentive schemes within a regulatory control period to align distributor incentives with the NEO. In implementing the STPIS we need to be aware of both the operational integrity of the scheme and how it interacts with our other incentive schemes. This is discussed below.

Defining performance targets

How we measure actual service performance and set performance targets can significantly impact how well the STPIS meets its stated objectives.

The NER require us to consider past performance of the distributor's network in developing and implementing the STPIS.[161] Our preferred approach is to base performance targets on

158 Charles River Associates, *Assessment of the Value of Consumer Reliability (VCR) - Report prepared for VENCorp*, Melbourne 2002; KPMG, *Consumer Preferences for Electricity Service Standards*, 2003.

159 AEMO, *Value of customer reliability review - Final report*, September 2014.

160 AER, *Preliminary framework and approach for NSW distributors 2019-24*, March 2017, p. 57.

161 NER, cl. 6.6.2(b)(3)(iii).

SA Power Networks' average performance over the past five regulatory years.[162] Using an average calculated over multiple years instead of applying performance targets based solely on the most recent regulatory year limits a distributor's incentive to underperform in a specific year to make future targets less onerous.

Under this approach, distributors will only receive a financial reward for achieving reliability improvements. More importantly, a distributor can only retain the reward if it can maintain the reliability improvements. This is because once an improvement is made; the benchmark performance targets will be adjusted to reflect the improved level of performance. If it allows reliability to decline in the future, the distributor will be penalised. Our STPIS limits variability in penalties and rewards caused by circumstances outside the distributor's control. We exclude interruptions to supply deemed to be outside the major event day boundary from both the calculation of performance targets and measured service performance.

Interactions with our other incentive schemes

In applying the STPIS we must consider any other incentives available to the distributor under the NER or relevant distribution determination.[163] In SA the STPIS will interact with our expenditure and demand management incentive schemes.

The efficiency benefit sharing scheme (EBSS) provides a distributor with an incentive to reduce operating costs. The STPIS counterbalances this incentive by discouraging cost reductions that lead to a decline in performance. The s-factor adjustment of annual revenue depends on the distributor's actual service performance compared to predetermined targets.

In setting STPIS performance targets, we will consider both completed and planned reliability improvements expected to materially affect network reliability performance.[164]

The capital expenditure sharing scheme (CESS) rewards a distributor if actual capex is lower than the approved forecast amount for the regulatory year. Since our performance targets will reflect planned reliability improvements, any incentive a distributor may have to reduce capex by not achieving the planned performance outcome will be curtailed by the STPIS penalty.

3.2 Efficiency benefit sharing scheme

The EBSS is intended to provide a continuous incentive for distributors to pursue efficiency improvements in opex, and provide for a fair sharing of these between distributors and consumers. Consumers benefit from improved efficiencies through lower network prices in future regulatory control periods.

162 Subject to any modifications required under cll. 3.2.1(a) and (b) of the national STPIS.

163 NER, cl. 6.6.2(b)(3)(iv).

164 Included in the distributor's approved forecast capex for the next period.

We address our position on the application of the EBSS in relationship to our proposed opex forecasting approach and benchmarking below. We also explain the rationale underpinning the scheme.

This section sets out our preliminary position and reasons on how we intend to apply the EBSS to SA Power Networks in the 2020–25 regulatory control period.

3.2.1 AER's preliminary position

We intend to apply the EBSS to SA Power Networks in the 2020–25 regulatory control period if we are satisfied the scheme will fairly share efficiency gains and losses between SA Power Networks and consumers.[165] This will occur only if the opex forecast for the following period is based on SA Power Networks' revealed costs. Our distribution determination for SA Power Networks for the 2020–25 regulatory control period will specify if and how we will apply the EBSS.[166]

SA Power Networks has indicated in its request to replace the current F&A that it sees no reason to alter the application of the EBSS for the 2020−25 regulatory control period.[167]

3.2.2 AER's assessment approach

The EBSS must provide for a fair sharing of opex efficiency gains and efficiency losses between a network service provider and network users.[168] We must also have regard to the following factors in developing and implementing the EBSS:[169]

- the need to ensure that benefits to electricity consumers likely to result from the scheme are sufficient to warrant any reward or penalty under the scheme
- the need to provide service providers with a continuous incentive to reduce opex
- the desirability of both rewarding service providers for efficiency gains and penalising service providers for efficiency losses
- any incentives that service providers may have to capitalise expenditure
- the possible effects of the scheme on incentives for the implementation of non-network alternatives.

3.2.3 Reasons for AER's preliminary position

The EBSS applies to SA Power Networks in the 2015–20 regulatory control period.[170]

165 NER, cl. 6.5.8(a).

166 AER, *Efficiency benefit sharing scheme*, 29 November 2013.

167 SA Power Networks, *Request to replace the framework and approach*, 31 October 2017, p. 3.

168 NER, cl. 6.5.8(a).

169 NER, cl. 6.5.8(c).

170 AER, *Electricity distribution network service providers, efficiency benefit sharing scheme*, 26 June 2008.

We will decide if and how we will apply the EBSS to SA Power Networks in the 2020–25 regulatory control period in our determination. The decision to apply the EBSS will depend on whether we expect to use the distributor's revealed costs in the 2020–25 regulatory control period to forecast opex in the following period.

Why we would apply the EBBS

We will only apply the EBSS in the 2020–25 regulatory control period if we expect we will use a revealed cost forecasting approach to forecast opex for the 2025–30 regulatory control period.

The EBSS is intrinsically linked to our revealed cost forecasting approach. This approach relies on identifying an efficient opex amount in the base year (the 'revealed costs' of the distributor), which we use to develop a total opex forecast. When a business makes an incremental efficiency gain, it receives a reward through the EBSS, and consumers benefit through a lower revealed cost forecast for the subsequent period. This is how efficiency improvements are shared between consumers and the business.

Under a revealed cost approach without an EBSS, a distributor has an incentive to spend more opex in the expected base year. Also, a distributor has less incentive to reduce opex towards the end of the regulatory control period, where the benefit of any efficiency gain is retained for less time.

If we use a revealed cost forecasting approach we apply the EBSS because:

- it reduces the incentive for a distributor to inflate opex in the expected base year in order to gain a higher opex forecast for the next regulatory control period
- it provides a continuous incentive for a distributor to pursue efficiency improvements across the regulatory control period. This is because the EBSS allows a distributor to retain efficiency gains for a total of six years, regardless of the year in which it was made.

In implementing the EBSS we also consider any incentives distributors may have to capitalise expenditure.[171] Where opex incentives are balanced with capex incentives, a distributor does not have an incentive to favour opex over capex, or vice-versa. If the CESS and EBSS are both applied, these incentives will be relatively balanced. We discuss the CESS further in section 3.3.

We also consider the effects of implementing the EBSS on incentives for non-network alternatives[172] (which are generally opex rather than capex). When the CESS and EBSS both apply, a distributor has an incentive to implement a non-network alternative if the increase in opex is less than the corresponding decrease in capex. In this way the distributor

171 NER, cl. 6.5.8(c)(4).
172 NER, cl. 6.5.8(c)(5).

will receive a net reward for implementing the non-network alternative.[173] Non-network alternatives and the demand management incentives, including the new DMIS, are discussed further in section 3.4.

We are currently reviewing the interaction of operating expenditure forecasts, the EBSS and the new DMIS. SA Power Networks supports the DMIS but noted consideration was required about the how the DMIS would interact with the application of the EBSS and opex benchmarking.[174] We will seek to confirm our position as part of the regulatory determination process, but note that in implementing the EBSS and DMIS we will seek to provide balanced opex and capex incentives that encourage a distributor to identify and undertake efficient demand management options.

Why we would not apply the EBBS

We will not apply the EBSS if it is likely we will *not* use a revealed cost forecasting approach to forecast opex for the 2025–30 regulatory control period.

If we apply the EBSS but do not forecast opex using revealed costs, a distributor could in theory receive an EBSS reward for efficiency gains (at a cost to consumers), but consumers would not benefit through a lower revealed cost forecast. If the distributor expects this, it has an incentive to increase its EBSS carryover by underspending in its base year, knowing the underspend will not reduce its opex forecast.[175] Consumers would pay the EBSS reward but not receive a share of the underspend and would be worse off. This outcome is contrary to the NER which requires that the EBSS must provide for a fair sharing of efficiency gains and losses between a distributor and consumers.[176]

If a distributor's revealed costs in the 2015–20 regulatory control period are materially higher than the opex incurred by a benchmark efficient distributor, we will be unlikely to use revealed costs to forecast opex for the 2020–25 regulatory control period. In which case, we will be unlikely to apply the EBSS.

3.3 Capital expenditure sharing scheme

The CESS provides incentives for distributors to undertake efficient capex throughout the regulatory control period by rewarding efficiency gains and penalising efficiency losses. Consumers benefit from improved efficiency through lower network prices in the future. This

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173 When the distributor spends more on opex it incurs approximately 30 per cent of that increase as a result of the EBSS. At the same time it retains 30 per cent of the capex decrease through the CESS. So where the decrease in capex is larger than the increase in opex the distributor receives a larger reward than penalty, a net reward..

174 SA Power Networks, *Request to replace the framework and approach*, 31 October 2017, p. 3.

175 In our explanatory statement to the EBSS, we discuss why we should exclude the expenditure categories not forecast using a single year revealed cost forecasting method from the EBSS to prevent network users being worse off. AER, *Explanatory statement - efficiency benefit sharing scheme*, November 2013, pp. 18-19.

176 NER, cl 6.5.8(a).

section sets out our proposed approach and reasons for our intention to apply version 1 (dated 29 November 2013) of the CESS to the distributors.

The CESS approximates efficiency gains and efficiency losses by calculating the difference between forecast and actual capex. It shares these gains or losses between a distributor and network users.

The CESS works as follows:

- We calculate the cumulative underspend or overspend amount for the current regulatory control period in net present value terms.
- We apply the sharing ratio of 30 per cent to the cumulative underspend or overspend amount to work out what the distributor's share of any underspend or overspend should be.
- We calculate the CESS payments taking into account the financing benefit or cost to the distributor of any underspend or overspend amounts.[177] We can also make further adjustments to account for deferral of capex and ex post exclusions of capex from the RAB.
- The CESS payments will be added to or subtracted from the distributor's regulated revenue as a separate building block in the next regulatory control period.

Under the CESS a distributor retains 30 per cent of the financing benefit or cost of any underspend or overspend amount, while consumers retain 70 per cent of the financing benefit or cost of any underspend or overspend amount.

3.3.1 AER's preliminary position

Our preliminary position is to apply the CESS, as set out in our capex incentives guideline,[178] to SA Power Networks in each regulatory year of the 2020−25 regulatory control period.

SA Power Networks has indicated in its request to replace the current F&A that it sees no reason to alter the application of the CESS for the 2020−25 regulatory control period.[179]

3.3.2 AER's assessment approach

In deciding whether to apply a CESS to a distributor, and the nature and details of any CESS to apply to a distributor, we must:[180]

177 We calculate benefits as the benefits to the distributor of financing the underspend since the amount of the underspend can be put to some other income generating use during the period. Losses are similarly calculated as the financing cost to the distributor of the overspend.

178 AER, *Capital expenditure incentive guideline for electricity network service providers*, pp. 5–9.

179 SA Power Networks, *Request to replace the framework and approach*, 31 October 2017, p. 3.

180 NER, cl. 6.5.8A(e).

- make that decision in a manner that contributes to the capex incentive objective set out in the NER[181]
- consider the CESS principles,[182] capex objectives,[183] other incentive schemes, and where relevant the opex objectives, as they apply to the particular distributor, and the circumstances of the distributor.

Broadly speaking, the capex incentive objective is to ensure that only capex that meets the capex criteria enters the RAB used to set prices. Therefore, consumers only fund capex that is efficient and prudent.

3.3.3 Reasons for AER's preliminary position

We propose to apply the CESS to SA Power Networks in the next regulatory control period as we consider this will contribute to the capex incentive objective.

SA Power Networks are currently subject to a CESS. As part of our Better Regulation program we consulted on and published version 1 of the capex incentives guideline which sets out the CESS.[184] The guideline specifies that in most circumstances we will apply a CESS, in conjunction with forecast depreciation to roll-forward the RAB.[185] We are also proposing to apply forecast depreciation, which we discuss further in chapter 5. In developing the CESS we took into account the capex incentive objective, capex criteria, capex objectives, and the CESS principles. We also developed the CESS to work alongside other incentive schemes that apply to distributors including the, STPIS, and DMIS.

For capex, the sharing of underspends and overspend amounts happens at the end of each regulatory control period when we update a distributor's RAB to include new capex. If a distributor spends less than its approved forecast during a period, it will benefit within that period. Consumers benefit at the end of that period when the RAB is updated to include less capex compared to if the business had spent the full amount of the capex forecast. This leads to lower prices in the future.

Without a CESS the incentive for a distributor to spend less than its forecast capex declines throughout the period.[186] Because of this a distributor may choose to spend capex earlier, or spend on capex when it may otherwise have spent on opex, or less on capex at the expense of service quality—even if it may not be efficient to do so.

With the CESS a distributor faces the same reward and penalty in each year of a regulatory control period for capex underspends or overspends. The CESS will provide a distributor

181 NER, cl. 6.4A(a); the capex criteria are set out in cl. 6.5.7(c) of the NER.

182 NER, cl.6.5.8A(c).

183 NER, cl. 6.5.7(a).

184 AER, *Capital expenditure incentive guideline for electricity network service providers*, pp. 5–9.

185 AER, *Capital expenditure incentive guideline for electricity network service providers*, pp. 10–12.

186 As the end of the regulatory period approaches, the time available for the distributor to retain any savings gets shorter. So the earlier a distributor incurs an underspend in the regulatory period, the greater its reward will be.

with an ex ante incentive to spend only efficient capex in each year of the regulatory control period. A distributor that makes an efficiency gain will be rewarded through the CESS. Conversely, a distributor that makes an efficiency loss will be penalised through the CESS. In this way, a distributor will be more likely to incur only efficient capex when subject to a CESS, so any capex included in the RAB is more likely to reflect the capex criteria. In particular, if a distributor is subject to the CESS, its capex is more likely to be efficient and to reflect the costs of a prudent distributor.

In addition, when the CESS, EBSS and STPIS apply to a distributor then incentives for opex, capex and service performance are balanced. This encourages a distributor to make efficient decisions on when and what type of expenditure to incur, and to balance expenditure efficiencies with service quality.

Relevantly, as emphasised as part of the development of our guideline, while our forecast of capex for a regulatory control period is partly informed by our forecast of the prudent and efficient capex the network service provider will need to complete discrete projects or programs this is only to inform our total forecast of capex for the regulatory control period. Importantly, while we may consider certain projects and programs in forming a view on the total capex forecast, we do not determine which projects and programs the network service provider should or should not undertake. This is consistent with the incentive based regulatory framework.

Once we approve total revenue, the network service provider is able to prioritise its capex program given its circumstances over the course of the regulatory control period. This means, a network service provider may choose to defer some discrete projects that we initially considered when forming our view of the total capex forecast for the regulatory control period. Conversely, it may also choose to bring forward other discrete projects that we had not previously assessed when setting the network service provider's forecast of capex for the regulatory control period. This means that it is not appropriate to consider our determinations as approving specific projects and programs.

3.4 Demand management incentive scheme and demand management innovation allowance mechanism

We established a new demand management incentive scheme (DMIS) and demand management innovation allowance mechanism (DMIA) in December 2017. [187] It is intended that the new DMIS and DMIA are to apply to SA Power Networks in the 2020−25 regulatory control period.

DMIS is intended to encourage distribution businesses to find lower cost solutions to investing in network solutions. The incentive scheme achieves this by encouraging

187 https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/demand-management-incentive-scheme-and-innovation-allowance-mechanism

distribution businesses to undertake efficient expenditure on non-network options relating to demand management.

We have also improved our existing DMIA to provide research and development (R&D) fund to help distribution businesses discover new ways of using demand management to keep the costs down for electricity consumers in the future. Its objective is to provide distribution businesses with funding for R&D in demand management projects that have the potential to reduce long term network costs. This will fund innovative projects that have the potential to deliver ongoing reductions in demand or peak demand.

3.4.1 Reasons for AER's preliminary position

Distribution businesses can manage demand on their networks to reduce, delay or even avoid the need to install, replace or upgrade expensive network assets. Network assets include equipment like poles, wires, transformers and substations. When used effectively, managing demand to avoid incurring these costs can reduce upward pressure on network charges, which make up about half the cost of electricity bills.

Managing demand on electricity networks can increase the reliability of supply and reduce the cost of supplying electricity. Often, electricity consumers are empowered to manage demand via price signals and enabling technology.

Price signals or financial incentives can reward consumers for using electricity in a way that allows network businesses to keep their costs down. These signals or incentives may come in the form of things like cost-reflective tariffs, congestion pricing, and rebates. Enabling technology often complements price signals by empowering consumers use electricity in a way that allows network businesses to keep their costs down. This technology may include things like advanced metering technology, demand response enabling devices, and energy monitoring aps.

The revised DMIS only allows the implementation of demand management projects that are efficient and contribute, partially or wholly, to resolving a network constraint. In deciding whether a project is efficient, we require distribution businesses to test the demand management services market. This will increase transparency, promote competition and put downwards pressure on electricity prices. This is because distribution business can only benefit from incentives if they address the network constraint in the most efficient way available.

This incentive structure should encourage best-practice network planning that will deliver value to consumer via lower electricity prices. We believe our incentive scheme will achieve this because distribution businesses will be:

- Selecting efficient projects that deliver the most value to consumers when solving network constraints, regardless of whether these projects constitute a demand-side or supply-side solution.

- Asking third parties to propose demand management solutions, and forming contracts with parties that propose solutions that deliver the most value to consumers.

We will continue providing a demand management innovation allowance, which is an R&D fund, because the innovation allowance will complement the new DMIS. It will increase the capacity of distribution business to invest in ideas that may eventually form parts of projects under the incentive scheme.

We believe that DMIS, supported by DMIA, will provide long term benefit to customers.

3.4.2 AER's preliminary position

We intend to apply our new demand management incentive scheme (DMIS) and demand management innovation allowance mechanism (DMIA) as published by us in December 2017 to apply to SA Power Networks in the 2020−25 regulatory control period.

3.4.3 AER's assessment approach to the DMIS

We will assess the proposed projects under DMIS and DMIA under the assessment criteria prescribed by the scheme documents.

4 Expenditure forecast assessment guideline

This chapter sets out our intention to apply our expenditure forecast assessment guideline (the EFA guideline)[188] including the information requirements applicable to SA Power Networks for the 2020−25 regulatory control period. The EFA guideline sets out our expenditure forecast assessment approach developed and consulted upon during the Better Regulation program. It outlines the assessment techniques we will use to assess a distributor's proposed expenditure forecasts, and the information we require from the distributor.

The EFA guideline uses a nationally consistent reporting framework that allows us to compare the relative efficiencies of distributors and decide on efficient expenditure forecasts. The NER requires SA Power Networks to advise us by 30 June 2018 of the methodology they propose to use to prepare their forecasts.[189] In the final F&A, we must advise whether we will deviate from the EFA guideline.[190] This will provide clarity on how we will apply the EFA guideline and the information SA Power Networks should include in their regulatory proposal. This contributes to an open and transparent process and makes our assessment of expenditure forecasts more predictable. The EFA guideline contains a suite of assessment/analytical tools and techniques to assist our review of the expenditure forecasts that distributors include in their regulatory proposals. We intend to have regard to the assessment tools set out in the guideline. The tool kit includes:

- models for assessing proposed replacement and augmentation capex
- benchmarking (including broad economic techniques and more specific analysis of expenditure categories)
- methodology, governance and policy reviews
- predictive modelling and trend analysis
- cost benefit analysis and detailed project reviews.[191]

We exercise judgement to determine the extent to which we use a particular technique to assess a regulatory proposal. We use the techniques we consider appropriate depending on the specific circumstances of the determination. The guideline is flexible and recognises that we may employ a range of different estimating techniques to assess an expenditure forecast.

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188 We were required to develop the EFA guideline under clauses 6.4.5 and 11.53.4 of the NER. We published the guideline on 29 November 2013. It can be located at www.aer.gov.au/node/18864.

189 NER, cl. 6.8.1A(b)(1).

190 NER, cl. 6.8.1(b)(2)(viii).

191 AER, *Explanatory statement: Expenditure assessment guideline for electricity transmission and distribution*, 29 November 2013.

For opex, in most cases we take a base-step-trend approach to assessing forecast expenditure and in this context use top down economic benchmarking tools to determine the reasonableness of the forecast rather than a bottom-up assessment approach. However, in exercising our judgement, we may use any analytical tool at our disposal, including assessing individual elements of the forecast using a bottom-up approach.

We will continue to develop and use economic benchmarking to inform our expenditure decisions consistent with the EFA guideline. Economic benchmarking remains a tool in assessing the relative efficiency of network services providers. We are likely to use a range of benchmarking approaches in assessing expenditure forecasts. Benchmarking also provides a source of information to assist both service providers and other interested parties about the relative productivity of individual businesses and the trends in productivity for the industry.

In the context of continuously improving economic benchmarking, we are currently reviewing and refining our analysis of operating environment factors in consultation with industry and other interested parties. The consultation with industry is ongoing and we are looking to finalise the review in mid-2018.[192] We will then seek to implement any recommended improvements from that process in our annual benchmarking and regulatory determination processes.

[192] More information is available at https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/review-of-operating-environment-factors-for-distribution-network-service-providers.

5 Depreciation

As part of the process of rolling forward a distributor's RAB to the start of the next regulatory control period, we update the RAB for actual capex incurred during the current regulatory control period and also adjust for depreciation. This chapter sets out our preliminary approach on the form of depreciation to be used when SA Power Networks' RAB is rolled forward to the commencement of the 2025–30 regulatory control period.

The depreciation we use to roll forward the RAB can be based on either:

- Actual capex incurred during the regulatory control period (actual depreciation). We roll forward the RAB based on actual capex less the depreciation on the actual capex incurred by the distributor; or
- The capex allowance forecast at the start of the regulatory control period (forecast depreciation). We roll forward the RAB based on actual capex less the depreciation on the forecast capex approved for the regulatory control period.

The choice of depreciation approach is one part of the overall capex incentive framework.

Consumers benefit from improved efficiencies through lower regulated prices. Where a CESS is applied, using forecast depreciation maintains the incentives for distributors to pursue capex efficiencies, whereas using actual depreciation would increase these incentives. There is more information on depreciation as part of the overall capex incentive framework in our capex incentives guideline.[193] In summary:

- If there is a capex overspend, actual depreciation will be higher than forecast depreciation. This means that the RAB will increase by a lesser amount than if forecast depreciation was used. As a result, the distributor will earn less revenue into the future (i.e. it will bear more of the cost of the overspend into the future) than if forecast depreciation had been used to roll forward the RAB.
- If there is a capex underspend, actual depreciation will be lower than forecast depreciation. This means that the RAB will increase by a greater amount than if forecast depreciation was used. Hence, the distributor will earn greater revenue into the future (i.e. it will retain more of the benefit of an underspend into the future) than if forecast depreciation had been used to roll forward the RAB.

The incentive from using actual depreciation to roll forward the RAB also varies with the life of the asset. Using actual depreciation will provide a stronger incentive for the distributor to underspend capex on shorter lived assets compared to longer lived assets as this will lead to a relatively larger increase in the RAB. Use of forecast depreciation, on the other hand, leads to the same incentive for capex regardless of asset lives. This is because using forecast depreciation does not affect the distributor's incentive on capex as the distributor

193 AER, *Capital expenditure incentive guideline for electricity network service providers*, November 2013, pp. 10–12.

does not lose the full cost of any overspend and is not able to keep all the benefits of any underspend. To this end, using forecast depreciation means the capex incentive is focussed on the return on capital.

5.1 AER's preliminary position

Our preliminary position is to use the forecast depreciation approach to establish the RAB at the commencement of the 2025–30 regulatory control period for SA Power Networks. We consider this approach will provide sufficient incentives for SA Power Networks to achieve capex efficiency gains over the 2020–25 regulatory control period.

SA Power Networks supports this approach in its request to replace the current F&A.[194]

5.2 AER's assessment approach

We have to decide for our distribution determination whether we will use actual or forecast depreciation to establish a distributor's RAB at the commencement of the following regulatory control period.[195]

We set out in our capex incentives guideline our process for determining which form of depreciation we propose to use in the RAB roll forward process.[196] Our decision on whether to use actual or forecast depreciation must be consistent with the capex incentive objective. We must have regard to:[197]

- any other incentives the service provider has to undertake efficient capex
- substitution possibilities between assets with different lives
- the extent of overspending and inefficient overspending relative to the allowed forecast
- the capex incentive guideline
- the capital expenditure factors.

5.3 Reasons for AER's preliminary position

Consistent with our capex incentives guideline, we propose to use the forecast depreciation approach to establish the RAB for SA Power Networks at the commencement of the 2025–30 regulatory control period.

We had regard to the relevant factors in the NER in developing the approach for deciding on the form of depreciation set out in our capex incentives guideline.[198]

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194 SA Power Networks, *Request to replace the framework and approach*, 31 October 2017, p. 3.
195 NER, cl. S6.2.2B.
196 NER, cl. 6.4A(b)(3).
197 NER, cl. S6.2.2B.
198 AER, *Capital expenditure incentive guideline for electricity network service providers*, November 2013, pp. 10–12.

Our approach is to apply forecast depreciation except where:

- there is no CESS in place and therefore the power of the capex incentive may need to be strengthened, or
- a distributor's past capex performance demonstrates evidence of persistent overspending or inefficiency, thus requiring a higher powered incentive.

In making our decision on whether to use actual depreciation in either of these circumstances we will consider:

- the substitutability between capex and opex and the balance of incentives between these
- the balance of incentives with service outcomes
- the substitutability of assets with different asset lives.

We have chosen forecast depreciation as our default approach because, in combination with the CESS, it will provide a 30 per cent reward for capex underspends and 30 per cent penalty for capex overspends, which is consistent for all types of asset categories. In developing our capex incentives guideline, we considered this to be a sufficient incentive for a distributor to achieve efficiency gains over the regulatory control period in most circumstances.

The opening RAB at the commencement of the 2020–25 regulatory control period will be established using forecast depreciation, as stated in our previous determination that applies to SA Power Networks for the 2015–20 regulatory control period. The use of forecast depreciation to establish the opening RAB for the commencement of the 2025–30 regulatory control period therefore maintains the current approach. SA Power Networks is currently subject to a CESS and we propose to continue to apply the CESS in the 2020–25 regulatory control period. We discuss this in section 3.3.

For SA Power Networks, we consider the incentive provided by the application of the CESS in combination with the use of forecast depreciation and our other ex post capex measures should be sufficient to achieve the capex incentive objective.[199] Our ex post capex measures are set out in the capex incentives guideline. The guideline also sets out how all our capex incentive measures are consistent with the capex incentive objective.

199 AER, *Capital expenditure incentive guideline for electricity network service providers*, November 2013, pp. 13–19 and 20–21.

Appendix A: Rule requirements for classification

We must have regard to four factors when classifying distribution services.[200]

- the form of regulation factors in section 2F of the NEL:
  - the presence and extent of any barriers to entry in a market for electricity network services
  - the presence and extent of any network externalities (that is, interdependencies) between an electricity network service provided by a network service provider and any other electricity network service provided by the network service provider
  - the presence and extent of any network externalities (that is, interdependencies) between an electricity network service provided by a network service provider and any other service provided by the network service provider in any other market
  - the extent to which any market power possessed by a network service provider is, or is likely to be, mitigated by any countervailing market power possessed by a network service user or prospective network service user
  - the presence and extent of any substitute, and the elasticity of demand, in a market for an electricity network service in which a network service provider provides that service
  - the presence and extent of any substitute for, and the elasticity of demand in a market for, elasticity or gas (as the case may be)
  - the extent to which there is information available to a prospective network service user or network service user, and whether that information is adequate, to enable the prospective network service user or network service user to negotiate on an informed basis with a network service provider for the provision of an electricity network service to them by the network service provider.[201]
- the form of regulation (if any) previously applicable to the relevant service or services, and, in particular, any previous classification under the present system of classification or under the present regulatory system (as the case requires)[202]
- the desirability of consistency in the form of regulation for similar services (both within and beyond the relevant jurisdiction)[203]
- any other relevant factor.[204]

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200 NER, cl. 6.2.1(c).
201 NEL, s. 2F.
202 NER, cl. 6.2.1(c)(2).
203 NER, cl. 6.2.1(c)(3).
204 NER, cl. 6.2.1(c).

The AEMC contestability of energy services rule change[205] removes the previous requirements under the previous rules under clauses 6.2.1(d) and 6.2.2(d) that we must, when classifying a distribution service, not depart from a previous classification or the previously applicable regulatory approach (as the case may be) when classifying a distribution service, unless that different classification is "clearly more appropriate".

The rule change also amends the existing threshold that must be satisfied before we can change a service classification or control mechanism formulae between a framework and approach paper and the distribution determination – the existing threshold of "unforeseen circumstances" has been changed to "a material change in circumstances.[206]

We must have regard to six factors when classifying direct control services as either standard control or alternative control services.[207]

- the potential for development of competition in the relevant market and how the classification might influence that potential
- the possible effects of the classification on administrative costs of us, the distributor and users or potential users
- the regulatory approach (if any) applicable to the relevant service immediately before the commencement of the distribution determination for which the classification is made
- the desirability of a consistent regulatory approach to similar services (both within and beyond the relevant jurisdiction)
- the extent that costs of providing the relevant service are directly attributable to the customer to whom the service is provided, and
- any other relevant factor.[208]

In classifying direct control services that have previously been subject to regulation under the present or earlier legislation, we must also follow the requirements of clause 6.2.2(d) of the NER.

205 AEMC, final rule determination - National Electricity Amendment (Contestability of Energy Services) 2017
206 NER 6.12.3(b) and (c1) under the final rule.
207 NER, cl. 6.2.2(c).
208 NER, cl. 6.2.2(c).

Appendix B: Proposed service classification of SA Power Networks' distribution services 2020−25[209]

Service group	Further description	Current classification 2015-20	AER proposed classification 2020-25
Common distribution service			
Common distribution service (formerly 'network services')	The suite of activities involved in the provision of the distribution network for the conveyance of electricity (including the service that ensures the integrity of the related distribution system) and includes but is not limited to the following: • the planning, design, repair, maintenance, construction and operation of the distribution network • the relocation of assets that form part of the distribution network but not relocations requested by a third party (including a customer) • works to fix damage to the network (including emergency recoverable works) • support for another distributor during an emergency event • network demand management for distribution purposes • training internal staff and contractors undertaking direct control services	Standard Control	Standard Control

209 The examples and activities listed in the 'Further description' column are not intended to be an exhaustive list and some distributors may not offer all activities listed. Rather the examples provide a sufficient indication of the types of activities captured by the service.

Service group	Further description	Current classification 2015-20	AER proposed classification 2020-25
	• activities related to 'shared asset facilitation' of distributor assets • emergency disconnect for safety reasons and work conducted to determine if a customer outage is related to a network issue • bulk supply point metering • rectification of simple customer fault (e.g. fuse) relating to a life support customer • establishment and maintenance of national metering identifiers (NMIs) in market and/or network billing systems • investigation of customer-reported network faults. Such services do not include a service that has been separately classified including any activity relating to that service.		
Ancillary services - Services closely related to common distribution services but for which a separate charge applies.			
Connection application related services	Activities include: • assessing connection applications and preparing offers • processing preliminary enquiries requiring site specific or written responses • undertaking planning studies and associated technical analysis (e.g. power quality investigations) to determine suitable/feasible connection options for further consideration by applicants • site inspection in order to determine the nature of the connection service sought by the connection applicant and ongoing co-ordination for large projects • registered participant support services associated with connection arrangements and	Negotiated Distribution Service	Alternative control

Service group	Further description	Current classification 2015-20	AER proposed classification 2020-25
	agreements made under Chapters 5 of the NER.		
Access permits, oversight and facilitation services	Activities include: • a distributor issuing access permits or clearances to work to a person authorised to work on or near distribution systems including high and low voltage. • a distributor issuing confined space entry permits and associated safe entry equipment to a person authorised to enter a confined space. • a distributor providing access to switch rooms, substations and the like to a non-LNSP party who is accompanied and supervised by a distributor's staff member. May also include a distributor providing safe entry equipment (fall-arrest) to enter difficult access areas. • specialist services (which may involve design related activities and oversight/inspections of works) where the design or construction is non-standard, technically complex or environmentally sensitive and any enquiries related to distributor assets. • facilitation of generator connection and operation on the network. • facilitation of activities within clearances of distributor's assets, including physical and electrical isolation of assets. • sales of approved materials/equipment to third parties for connection assets that are gifted back to become part of the shared distribution network.	Negotiated distribution service	Alternative Control
Third party funded network upgrades or other improvements.	Upgrades or alterations to the shared distribution network to enable third party infrastructure (e.g. NBN Co telecommunications assets) to be installed on the shared	Negotiated distribution	Alternative Control

Service group	Further description	Current classification 2015-20	AER proposed classification 2020-25
	distribution network. This does not relate to upstream distribution network augmentation.	service	
Network safety services	Examples include: • provision of traffic control and safety observer services by the distributor where required • fitting of tiger tails and aerial markers • high load escorts • customer initiated outage (e.g. to allow customer and/or contractor to perform maintenance on the customer's assets, work close or for safe approach).	Negotiated distribution service	Alternative control
Rectification works to maintain network safety	Activities include issues identified by the DNSP and work involved in managing and resolving pre-summer bushfire inspection customer vegetation defects or aerial mains where the customer has failed to do so.	Not previously classified	Alternative control
Planned interruption – customer requested	Where the customer requests to move a planned interruption, and agrees to fund the additional cost of performing this distribution service outside of normal business hours.	Negotiated distribution service	Alternative Control
Attendance at customers' premises to perform a statutory right where access is prevented	A follow up attendance at a customer's premises to perform a statutory right where access was prevented or declined by the customer on the initial visit. This may include the costs of arranging, and the provision of, a security escort or police escort (where the cost is passed through to the distributor).	Negotiated distribution service	Alternative Control
Inspection services – private	Activities include:	Negotiated	Alternative

Service group	Further description	Current classification 2015-20	AER proposed classification 2020-25
electrical installations	• inspection and reinspection by a distributor of gifted assets or assets that have been installed or relocated by a third party • investigation, review and implementation of remedial actions that may lead to corrective and disciplinary action of a third party service provider due to unsafe practices or substandard workmanship • auditing of a third party service provider's work practices in the field • after hours examination and/or testing of the consumer mains and main switchboard prior to initial energisation (upon request) • after hours visual examination of an electrical installation to reconnect it to a source of electricity (upon request) • re-test at a customer's installation, where the installation fails the initial test and cannot be connected.	distribution service	Control
Provision of training to third parties for network related access	Training services provided to third parties that result in a set of learning outcomes that are required to obtain a distribution network access authorisation specific to a distributor's network. Such learning outcomes may include those necessary to demonstrate competency in the distributor's electrical safety rules, to hold an access authority on the distributor's network and to carry out switching on the distributor's network. Examples of training might include high voltage training, protection training or working near power lines training.	Not classified in SA	Alternative Control
Authorisation and approval of third party service providers design, work and materials	Activities include: • authorisation or re-authorisation of individual employees and subcontractors of third party service providers and additional authorisations at the request of the third party	Not previously classified	Alternative control

Service group	Further description	Current classification 2015-20	AER proposed classification 2020-25
	service providers (excludes training services). • acceptance of third party designs and works. • assessing an application from a third party to consider approval of alternative material and equipment items that are not specified in the distributor's approved materials list.		
Security lights	Provision, installation, operation and maintenance of equipment mounted on a distribution pole used for security services, e.g. nightwatchman lights Note: excludes connection services.	Negotiated distribution service	Alternative Control
Customer initiated asset relocations	• Relocation of assets that form part of the distribution network in circumstances where the relocation was initiated by a third party (including a customer).	Negotiated Distribution Service	Alternative control
Customer requested provision of electricity network data	Requests for the provision of electricity network data requiring customised investigation, analysis or technical input (e.g. requests for zone substation data)	Alternative control	Alternative control
Metering Services[210]			
Type 1 to 4 metering services	Type 1 to 4 metering installations and supporting services are competitively available.	Negotiated distribution service & Alternative	Unregulated

[210] SA Power Networks will continue to be responsible for type 5 and 6 meters until they are replaced (and entitled to levy associated charges). We refer to these meters as 'legacy meters'. New meters (that will be type 1 to 4 meters) installed from 1 December 2017 are referred to as 'contestable meters'.

Service group	Further description	Current classification 2015-20	AER proposed classification 2020-25
		Control	
Type 5 and 6 meter installation and provision (prior to 1 December 2017)	Recovery of the capital cost of type 5 and 6 metering equipment installed (including metering with internally integrated load control devices).	Alternative Control	Alternative Control
Type 5 and 6 meter maintenance, reading and data services (legacy meters)	• Meter maintenance covers works to inspect, test, maintain and repair metering installations. • Meter reading refers to quarterly or other regular reading of a metering installation. • Metering data services are those that involve the collection, processing, storage and delivery of metering data, the provision of metering data from the previous two years, remote or self-reading at difficult to access sites, and the management of relevant NMI Standing Data in accordance with the Rules NER.	Alternative Control	Alternative Control
Type 7 metering services	Administration and management of type 7 metering installations in accordance with the NER and jurisdictional requirements. Includes the processing and delivery of calculated metering data for unmetered loads, and the population and maintenance of load tables, inventory tables and on/off tables.	Standard Control	Standard Control
Ancillary metering services (Type 5 to 7 metering installations)	Activities include: • Off-cycle meter reads for type 5 and 6 meters. • Requests to test, inspect and investigate, or alter an existing type 5 or 6 metering installation. • Testing and maintenance of instrument transformers for type 5 and 6 metering purposes.	Negotiated distribution service	Alternative control

Service group	Further description	Current classification 2015-20	AER proposed classification 2020-25
	• Type 5 to 7 non-standard metering services. • Works to re-seal a type 5 or 6 meter due to customer or third party action (e.g. by having electrical work done on site). • Change distributor load control relay channel on request that is not a part of the initial load control installation, nor part of standard asset maintenance or replacement.		
Emergency maintenance of failed metering equipment not owned by DNSP (contestable metering)	The DNSP is called out by a customer or their agent (e.g. retailer, Metering Coordinator or Metering Provider) due to a power outage where an external Metering Provider's metering equipment has failed or an outage has been caused by the Metering Provider and the distributor has had to restore power to the customer's premises. This may result in an unmetered supply arrangement at this site. This fee will also be levied where a metering provider has requested the distributor to check a potentially faulty network connection and when tested by the distributor, no fault is found.	Not previously classified in SA	Alternative Control
Meter recovery and disposal – type 5 and 6 (legacy meters)	Activities include the removal and disposal of a type 5 or 6 metering installation: • at the request of the customer or their agent, where an existing type 5 or 6 metering installation remains installed at the premises and a replacement meter is not required. • at the request of the customer or their agent, where a permanent disconnection has been requested where it has not been removed and disposed of by the incoming metering provider.	Not previously classified in SA	Alternative Control
Third party requested outage for purposes of replacing meter	At the request of a retailer or metering coordinator provide notification to affected customers and facilitate the disconnection/reconnection of customer metering installations where a retailer planned interruption cannot be conducted.	Not previously classified in SA	Alternative control

Service group	Further description	Current classification 2015-20	AER proposed classification 2020-25
Connection Services			
Connection services	Connection Services include: • Premises connection services – includes any additions or upgrades to the connection assets located on the customer's premises (note: excludes all metering services). • Extensions – includes an enhancement required to connect a powerline or facility outside the present boundaries of the transmission or distribution network owned or operated by a DNSP • Network augmentations – includes any shared network enlargement / enhancement undertaken by a distributor which is not an extension. These services are subject to customer contributions determined according to SA Power Networks' Connection Policy These services exclude connection service for large embedded generators (30 kW 3 phase and above or 5 kW 1 phase and above. See below).	Standard Control	Standard Control
Non-standard connection services	Other or enhanced connection services provided at the request of a customer or third party that include those that are: • Provided with higher quality of reliability standards, or lower quality or reliability standards (where permissible) than required by the NER or any other applicable regulatory instruments; • In excess of levels of service or plant ratings required to be provided by SA Power Networks; • For large embedded generators (30 kW 3 phase or above 5 kW 1 phase and above);	Negotiated distribution service	Alternative Control

Service group	Further description	Current classification 2015-20	AER proposed classification 2020-25
	or • Other additional customer dedicated connection lines / assets.		
Connection management services	Works initiated by a customer or retailer which are specific to the connection point. Includes, but is not limited to: • de-energisation • re-energisation • temporary connections • remove or reposition connection • overhead service line replacement – customer requests the existing overhead service to be replaced (e.g. as a result of a point of attachment relocation). No material change to load • protection and power quality assessment • supply enhancement (e.g. upgrade from single phase to three phase) • provision of connection services above minimum requirements – customer requests increase in reliability or quality of supply beyond the standard, and/or above minimum regulatory requirements (e.g. reserve feeder) • customer requested change requiring secondary and primary plant studies for safe operation of the network (e.g. change protection settings) • upgrade from overhead to underground service • rectification of illegal connections or damage to overhead or underground service	Negotiated distribution service	Alternative Control

Service group	Further description	Current classification 2015-20	AER proposed classification 2020-25
	cables • calculation of a site specific distribution loss factor on request in respect of a generating unit up to 10 MW or a connection point for an end-user with actual or forecast load up to 40 GWh per annum capacity, as per clause 3.6.3(b1) of the NER • power factor correction.		
Public Lighting Services			
Public Lighting	Includes provision, construction and maintenance of public lighting and emerging public lighting technology.	Negotiated distribution service	Alternative Control
Unregulated Distribution Services - (non-exhaustive list)			
Distribution asset rental	Rental of distribution assets to third parties (e.g. office space rental, pole and duct rental for hanging telecommunication wires etc.).	Unregulated	Unregulated
Contestable metering support roles	Includes metering coordinator, metering data provider and metering provider for Type 1 to 4 metering installations.	Unregulated	Unregulated
Type 5 and 6 meter data management to other electricity distributors	The provision of type 5 and 6 meter data management to other electricity distribution network service providers.	Unregulated	Unregulated
Provision of training to third parties for work not associated with common distribution	Training programs provided to third parties for work that is not associated with the provision of common distribution services nor network access.	Unregulated	Unregulated

Service group	Further description	Current classification 2015-20	AER proposed classification 2020-25
services nor network services			